ATTACHMENT A

List of Appearances

****** ATTACHMENT A: LIST OF APPEARANCES *******

Last Updated on 26-JUN-2009 by: RC4 A0803002 LIST A0712020

******* PARTIES ********

Nora Sheriff Attorney At Law ALCANTAR & KAHL, LLP 33 NEW MONTGOMERY STREET, SUITE 1850 SAN FRANCISCO CA 94015 (415) 421-4143

For: Energy Producers and Users Coalition

Edward G. Poole Attorney At Law ANDERSON, DONOVAN & POOLE 601 CALIFORNIA STREET, SUITE 1300 SAN FRANCISCO CA 94108-2818 (415) 956-6413 epoole@adplaw.com

For: Western Manufactured Housing Community

Association.

nes@a-klaw.com

Paul Angelopulo Legal Division RM. 4107 505 VAN NESS AVE San Francisco CA 94102 3298 (415) 703-4742 pfa@cpuc.ca.gov For: DRA

Kendall H. Macvey, Esq. BEST, BEST & KRIEGER, LLP 3750 UNIVERSITY AVENUE, SUITE 300 RIVERSIDE CA 92501-1028 (951) 686-1450 kendall.macVey@bbklaw.com

For: Western Riverside Council of Governments

Scott Blaising Attorney At Law BRAUN BLAISING MCLAUGHLIN P.C. 915 L STREET, STE. 1270 SACRAMENTO CA 95814 (916) 682-9702 blaising@braunlegal.com

For: San Joaquin Valley Power Authority

Ronald Liebert Attorney At Law CALIFORNIA FARM BUREAU FEDERATION 2300 RIVER PLAZA DRIVE SACRAMENTO CA 95833 (916) 561-5657 rliebert@cfbf.com

For: California Farm Bureau Federation

R. Thomas Beach Principal CROSSBORDER ENERGY 2560 NINTH STREET, SUITE 213A BERKELEY CA 94710-2557 (510) 549-6922 tomb@crossborderenergy.com

For: Solar Alliance

Steven Greenwald
J. JOSHUA DAVIDSON
DAVIS WRIGHT TREMAINE LLP
505 MONTGOMERY STREET, SUITE 800
SAN FRANCISCO CA 94111
(415) 276-6500
stevegreenwald@dwt.com
For: Simon Property Group, Inc.

Donald C. Liddell Attorney At Law DOUGLASS & LIDDELL 2928 2ND AVENUE SAN DIEGO CA 92103 (619) 993-9096 liddell@energyattorney.com For: Debenham Energy, LLC / Ice Energy, Inc.

Gregory S.G. Klatt DOUGLASS & LIDDELL 411 E. HUNTINGTON DRIVE NO.107-356 ARCADIA CA 91006 (818) 961-3002 klatt@energyattorney.com For: Alliance for Retail Energy Markets

Bill F. Roberts, Ph. D.
ECONOMIC SCIENCES CORPORATION
1516 LEROY AVENUE
BERKELEY CA 94708
(510) 841-6869
bill@econsci.com

For: Building Owners and Managers Association of California (BOMA)

****** ATTACHMENT A: LIST OF APPEARANCES *******

Last Updated on 26-JUN-2009 by: RC4 A0803002 LIST A0712020

Carolyn Kehrein
ENERGY MANAGEMENT SERVICES
2602 CELEBRATION WAY
WOODLAND CA 95776
(530) 668-5600
omlohrain@ams on com

cmkehrein@ems-ca.com For: Energy Users Forum

Norman J. Furuta Attorney At Law FEDERAL EXECUTIVE AGENCIES 1455 MARKET ST., SUITE 1744 SAN FRANCISCO CA 94103-1399 (415) 503-6994 norman.furuta@navy.mil

For: Federal Executive Agencies

Thomas J. Macbride, Jr.
Attorney At Law
GOODIN MACBRIDE SQUERI DAY & LAMPREY
LLP
505 SANSOME STREET, SUITE 900
SAN FRANCISCO CA 94111
(415) 392-7900
tmacbride@goodinmacbride.com
For: Building Owners and Managers Association of

Randall W. Keen Attorney At Law MANATT PHELPS & PHILLIPS, LLP 11355 WEST OLYMPIC BLVD. LOS ANGELES CA 90064 (310) 312-4361

rkeen@manatt.com
For: Los Angeles County

California

David L. Huard Attorney At Law MANATT, PHELPS & PHILLIPS, LLP ONE EMBARCADERO CENTER, 30TH FLOOR SAN FRANCISCO CA 94111 (415) 291-7400 dhuard@manatt.com

For: Lowe's Home Improvement

S. Nancy Whang Attorney At Law MANATT, PHELPS & PHILLIPS, LLP 11355 WEST OLYMPIC BLVD. LOS ANGELES CA 90064 (310) 312-4377 nwhang@manatt.com For: Los Angeles Unified School David J. Byers, Esq.
Attorney At Law
MCCRACKEN, BYERS & HAESLOOP, LLP
1920 LESLIE STREET
SAN MATEO CA 94403
(650) 377-4890
dbyers@landuselaw.com
For: California City-County Street Light Association
CAL-SLA

Andrew L. Niven
Attorney At Law
PACIFIC GAS AND ELECTRIC COMPANY
77 BEALE STREET, SUITE 3109
SAN FRANCISCO CA 94105
(415) 973-7572
aln2@pge.com

For: Pacific Gas and Electric

Shirley Woo Attorney At Law PACIFIC GAS AND ELECTRIC COMPANY PO BOX 7442 SAN FRANCISCO CA 94120 (415) 973-2248 SAW0@pge.com For: Pacific Gas and Electric

Maricruz Prado Attorney At Law SOUTHERN CALIFORNIA EDISON PO BOX 800, 2244 WALNUT GROVE AVENUE ROSEMEAD CA 91770 (626) 302-6943 maricruz.prado@sce.com For: SOUTHERN CALIFORNIA EDISON COMPANY

R. Olivia Samad
JENNIFER SHIGEKAWA, MARICRUZ PRADO
SOUTHERN CALIFORNIA EDISON COMPANY
PO BOX 800
2244 WALNUT GROVE AVENUE
ROSEMEAD CA 91770
(626) 302-3477
olivia.samad@sce.com
For: Southern California Edison Company

****** ATTACHMENT A: LIST OF APPEARANCES ******* Last Updated on 26-JUN-2009 by: RC4 A0803002 LIST A0712020

Keith Mccrea Attorney At Law SUTHERLAND ASHILL & BRENNAN 1275 PENNSYLVANIA AVENUE NW WASHINGTON DC 20004-2415 (202) 383-0705 keith.mccrea@sutherland.com

For: CA Manufacturers & Technology

Hayley Goodson Attorney At Law THE UTILITY REFORM NETWORK 711 VAN NESS AVENUE, SUITE 350 SAN FRANCISCO CA 94102

(415) 929-8876 hayley@turn.org

For: The Utility Reform Network

Douglas A. Ames Attorney At Law TRANSPHASE SYSTEMS, INC. 4971 LOS PATOS AVENUE HUNTINGTON BEACH CA 92649 (714) 377-4225 ames_doug@yahoo.com For: Transphase Co.

Paul Kerkorian
UTILITY COST MANAGEMENT LLC
6475 N. PALM AVENUE, SUITE 105
FRESNO CA 93704
(559) 261-9230
pk@utilitycostmanagement.com
For: Pleasant Valley Recreation and Park District /
"Citrus Packers" (Paramount Citrus, Limoneria Comp.,
LoBue Brothers, Inc.)

****** STATE EMPLOYEE ******

Robert Benjamin Energy Division AREA 4-A 505 VAN NESS AVE San Francisco CA 94102 3298 (415) 703-2494 bkb@cpuc.ca.gov

Andrew Campbell
Executive Division
RM. 5203
505 VAN NESS AVE
San Francisco CA 94102 3298
(415) 703-2501
agc@cpuc.ca.gov

Taaru Chawla Division of Ratepayer Advocates RM. 4209 505 VAN NESS AVE San Francisco CA 94102 3298 (415) 703-1546 tar@cpuc.ca.gov

Maryam Ghadessi Energy Division AREA 4-A 505 VAN NESS AVE San Francisco CA 94102 3298 (415) 703-1191 mmg@cpuc.ca.gov

Eric Greene Energy Division AREA 4-A 505 VAN NESS AVE San Francisco CA 94102 3298 (415) 703-5560 eg1@cpuc.ca.gov

Dexter E. Khoury Division of Ratepayer Advocates RM. 4209 505 VAN NESS AVE San Francisco CA 94102 3298 (415) 703-1200 bsl@cpuc.ca.gov For: DRA

Donald J. Lafrenz Energy Division AREA 4-A 505 VAN NESS AVE San Francisco CA 94102 3298 (415) 703-1063 dlf@cpuc.ca.gov

Dina S. Mackin Energy Division AREA 4-A 505 VAN NESS AVE San Francisco CA 94102 3298 (415) 703-2125 dm1@cpuc.ca.gov

Amy C. Yip-Kikugawa Administrative Law Judge Division RM. 2106 505 VAN NESS AVE San Francisco CA 94102 3298 (415) 703-5256 ayk@cpuc.ca.gov

****** ATTACHMENT A: LIST OF APPEARANCES ******* Last Updated on 26-JUN-2009 by: RC4 A0803002 LIST A0712020

****** INFORMATION ONLY *******

Daniel Geis
AGRICULTURAL ENERGY CONSUMERS ASSN.
925 L STREET, SUITE 800
SACRAMENTO CA 95814
(916) 447-6206
dgeis@dolphingroup.org
For: AGRICULTURAL ENERGY CONSUMERS
ASSOCIATION.

Karen Terranova ALCANTAR & KAHL, LLP 120 MONTGOMERY STREET, STE 2200 SAN FRANCISCO CA 94104 (415) 421-4143 filings@a-klaw.com

Evelyn Kahl Attorney At Law ALCANTAR & KAHL, LLP 33 NEW MONTGOMERY STREET, SUITE 1850 SAN FRANCISCO CA 94015 (415) 421-4143 ek@a-klaw.com For: Energy users and Producer's Coalition

Barbara R. Barkovich BARKOVICH & YAP, INC. PO BOX 11031 OAKLAND CA 94611 (510) 450-1270 brbarkovich@earthlink.net

Reed V. Schmidt BARTLE WELLS ASSOCIATES 1889 ALCATRAZ AVENUE BERKELEY CA 94703-2714 (510) 653-3399 X111 rschmidt@bartlewells.com

Ryan Bernardo BRAUN BLAISING MCLAUGHLIN, P.C. 915 L STREET, SUITE 1270 SACRAMENTO CA 95814 (916) 912-4432 bernardo@braunlegal.com

Maurice Brubaker BRUBAKER & ASSOCIATES, INC. 16690 SWINGLEY RIDGE ROAD, SUITE 140 CHESTERFIELD MO 63017 (636) 898-6725 mbrubaker@consultbai.com CALIFORNIA ENERGY MARKETS 425 DIVISADERO STREET, STE 303 SAN FRANCISCO CA 94117 (415) 963-4439 cem@newsdata.com

Docket Coordinator 5727 KEITH ST. OAKLAND CA 94618 (510) 597-1798 cpucdockets@keyesandfox.com

Josh Davidson DAVIS WRIGHT TREMAINE LLP 505 MONTGOMERY ST, STE 800 SAN FRANCISCO CA 94111-6533 (415) 276-6587 joshdavidson@dwt.com

Judy Pau DAVIS WRIGHT TREMAINE LLP 505 MONTGOMERY STREET, SUITE 800 SAN FRANCISCO CA 94111-6533 (415) 276-6587 judypau@dwt.com

Ralph E. Dennis DENNIS CONSULTING 2805 BITTERSWEET LANE LA GRANGE KY 40031 (502) 241-5686 ralphdennis@insightbb.com

Douglas M. Grandy, P.E. DG TECHNOLOGIES 1220 MACAULAY CIRCLE CARMICHAEL CA 95608 (916) 871-2432 dgrandy@caonsitegen.com For: California Onsite Generation

Wendy L. Illingworth ECONOMIC INSIGHTS 320 FEATHER LANE SANTA CRUZ CA 95060 (831) 427-2163 wendy@econinsights.com

Andrew Brown Attorney At Law ELLISON SCHNEIDER & HARRIS LLP 2600 CAPITOL AVENUE, SUITE 400 SACRAMENTO CA 95816-5905 (916) 447-2166 abb@eslawfirm.com

****** ATTACHMENT A: LIST OF APPEARANCES *******

Last Updated on 26-JUN-2009 by: RC4 A0803002 LIST A0712020

Jedediah J. Gibson Attorney At Law ELLISON SCHNEIDER & HARRIS LLP 2600 CAPITOL AVENUE, SUITE 400 SACRAMENTO CA 95816-5905 (916) 447-2166 jjg@eslawfirm.com

Kevin J. Simonsen ENERGY MANAGEMENT SERVICES 646 EAST THIRD AVENUE DURANGO CO 81301 (970) 259-1748 kjsimonsen@ems-ca.com

Melanie Gillette Western Regulatory Aafairs ENERNOC, INC. 115 HAZELMERE DRIVE FOLSOM CA 95630 (916) 501-9573 mgillette@enernoc.com

Jeanne B. Armstrong Attorney At Law GOODIN MACBRIDE SQUERI DAY & LAMPREY LLC 505 SANSOME STREET, SUITE 900 SAN FRANCISCO CA 94111 (415) 392-7900 jarmstrong@goodinmacbride.com

Michael B. Day Attorney At Law GOODIN MACBRIDE SQUERI DAY & LAMPREY LLP 505 SANSOME STREET, SUITE 900 SAN FRANCISCO CA 94111 (415) 392-7900 mday@goodinmacbride.com

Bill Marcus JBS ENERGY 311 D STREET, STE. A WEST SACRAMENTO CA 95605 (916) 372-0534 bill@jbsenergy.com

William H. Booth Attorney At Law LAW OFFICE OF WILLIAM H. BOOTH 67 CARR DRIVE MORAGA CA 94556 (925) 376-7370 wbooth@booth-law.com For: California Large Energy Consumers Association LINDH & ASSOCIATES 7909 WALERGA ROAD, SUITE 112, PMB 119 ANTELOPE CA 95843 (916) 729-1562 karen@klindh.com

Richard Mccann, Ph.D M. CUBED 2655 PORTAGE BAY ROAD, SUITE 3 DAVIS CA 95616 (530) 757-6363 rmccann@umich.edu

Karen Lindh

MRW & ASSOCIATES, INC. 1814 FRANKLIN STREET, SUITE 720 OAKLAND CA 94612 (510) 834-1999 mrw@mrwassoc.com For: MRW & ASSOCIATES, INC.

Case Coordination
PACIFIC GAS AND ELECTRIC COMPANY
PO BOX 770000; MC B9A
SAN FRANCISCO CA 94177
(415) 973-4744
regrelcpuccases@pge.com
For: PACIFIC GAS AND ELECTRIC COMPANY

Daniel Pease
PACIFIC GAS AND ELECTRIC COMPANY
77 BEALE STREET; B10A
SAN FRANCISCO CA 94103
DRP6@pge.com
For: PACIFIC GAS AND ELECTRIC COMPANY

Jim Ross RCS, INC. 500 CHESTERFIELD CENTER, SUITE 320 CHESTERFIELD MO 63017 (314) 530-9544 jimross@r-c-s-inc.com

Carol Manson
Regulatory Affairs
SAN DIEGO GAS & ELECTRIC CO.
8330 CENTURY PARK COURT CP32D
SAN DIEGO CA 92123-1530
(858) 650-4119
cmanson@semprautilities.com

For: SAN DIEGO GAS & ELECTRIC CO.

****** ATTACHMENT A: LIST OF APPEARANCES *******

Last Updated on 26-JUN-2009 by: RC4 A0803002 LIST A0712020

Kelly M. Foley Attorney At Law SAN DIEGO GAS & ELECTRIC COMPANY 101 ASH STREET, HQ12 SAN DIEGO CA 92101-3017 (619) 696-4287 kfoley@sempra.com

For: San Diego Gas and Electric Company

David Orth General Manager SAN JOAQUIN VALLEY POWER AUTHORITY 4886 EAST JENSEN AVENUE FRESNO CA 93725 (559) 237-5567 dorth@krcd.org

For: SAN JOAQUIN VALLEY POWER AUTHORITY

Jack L. Boyd Asst. General Counsel SIMON PROPERTY GROUP, INC. 225 WEST WASHINGTON ST. INDIANAPOLIS IN 46204 (317) 263-7098 jboyd@simon.com For: Simon Property Group, Inc.

Bruce Foster Senior Vice President SOUTHERN CALIFORNIA EDISON COMPANY 601 VAN NESS AVENUE, STE. 2040 SAN FRANCISCO CA 94102

(415) 775-1856

Bruce Reed Sr. Attorney SOUTHERN CALIFORNIA EDISON COMPANY 2244 WANUT GROVE AVE. ROSEMEAD CA 91770 (626) 302-4183 bruce.reed@sce.com

For: Southern California Edison Company

Case Administration
SOUTHERN CALIFORNIA EDISON COMPANY
LAW DEPARTMENT, ROOM 370
2244 WALNUT GROVE AVENUE, ROOM 370
ROSEMEAD CA 91770
(626) 302-4875
case.admin@sce.com
For: SOUTHERN CALFORNIA EDISON COMPANY

Jennifer Alderete
Case Administrator
SOUTHERN CALIFORNIA EDISON COMPANY
PO BOX 800, 244 WALNUT GROVE AVE
ROSEMEAD CA 91770
(602) 302-9967
Jennifer.Alderete@sce.com
For: SOUTHERN CALIFORNIA EDISON COMPANY

Jennifer Tsao Shigekawa Attorney At Law SOUTHERN CALIFORNIA EDISON COMPANY 2244 WALNUT GROVE AVENUE ROSEMEAD CA 91770 (626) 302-6819 Jennifer.Shigekawa@sce.com For: SOUTHERN CALIFORNIA EDISON COMPANY

Nina Suetake Attorney At Law THE UTILITY REFORM NETWORK 711 VAN NESS AVE., STE. 350 SAN FRANCISCO CA 94102 (415) 929-8876 X308 nsuetake@turn.org

Robert Finkelstein Legal Director THE UTILITY REFORM NETWORK 711 VAN NESS AVE., SUITE 350 SAN FRANCISCO CA 94102 (415) 929-8876 X307 bfinkelstein@turn.org

Michel P. Florio Attorney At Law THE UTILITY REFORM NETWORK (TURN) 711 VAN NESS AVENUE, SUITE.350 SAN FRANCISCO CA 94102 (415) 929-8876 mflorio@turn.org

Khojasteh Davoodi UTILITY RATES AND STUDIES OFFICE 1322 PATTERSON AVENUE SE WASHINGTON NAVY YARD DC 20374-5018 (202) 685-0130 khojasteh.davoodi@navy.mil

****** ATTACHMENT A: LIST OF APPEARANCES *******

Last Updated on 26-JUN-2009 by: RC4

A0803002 LIST

A0712020

Larry R. Allen UTILITY RATES AND STUDIES OFFICE SUITE 1000 1322 PATTERSON AVENUE SE WASHINGTON NAVY YARD DC 20374-5065 (202) 685-0130 larry.r.allen@navy.mil

(END OF ATTACHMENT A)

ATTACHMENT B

Revenue Allocation Settlement Agreement

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Southern California Edison)	
Company (U 338-E) To Establish Marginal)	Application 08-03-002
Costs, Allocate Revenues, And Design Rates)	(Filed March 4, 2008)
)	
In the Matter of the Application of Southern)	
California Edison Company (U 338-E) for)	Application 07-12-020
Authority to Make Various Electric Rate Design)	(Filed December 21, 2007)
Changes)	

REVENUE ALLOCATION SETTLEMENT AGREEMENT
SOUTHERN CALIFORNIA EDISON COMPANY 2009 GRC, PHASE 2
A.08-03-002/A.07-12-020

Dated: December 23, 2008

Southern California Edison Company Phase 2 Revenue Allocation Settlement Agreement A.08-03-002/A.07-012-020

Para	graph	Title	Page
1.	Parties		1
2.	Recitals		3
3.	Comparison Exhibit		4
4.	Definitions		4
5.	Agreement		6
6.	Implementation of Agreement		16
7.	Incorporation of Complete Agree	ment	17
8.	Signature Date		17
9.	Regulatory Approval		17
10.	Compromise Of Disputed Claims		17
11.	Non Precedent		17
12.	Previous Communications		18
13.	Non Waiver		18
14.	Effect Of Subject Headings		18
15.	Governing Law		18
16.	Number Of Originals		19

SETTLEMENT OF REVENUE ALLOCATION ISSUES IN PHASE 2 OF SOUTHERN CALIFORNIA EDISON COMPANY'S 2009 GENERAL RATE CASE (PHASE 2 REVENUE ALLOCATION AGREEMENT)

This Phase 2 Revenue Allocation Agreement (Agreement or Settlement Agreement) is entered into by 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); Energy Users Forum (EUF) Indicated Commercial Parties (ICP); California City-County Street Light Association (CAL-SLA); the Solar Alliance; the Building Owners and Managers Associations of Greater Los Angeles, Orange County, San Francisco, and California (BOMA); and the Energy Producers and Users Coalition (EPUC); (referred to hereinafter collectively as Parties or Settling Parties or individually as Party).

- 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.
- 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 85,000 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. Energy Users Forum is an ad hoc group that represents the interests of medium and large bundled service and direct access (DA) customers in California, with locations in either investor-owned utility and/or municipal utility service areas, taking service on rate schedules for accounts with demand above 100 kW. EUF represents entities that have accounts taking service on all SCE rate schedules from GS-2 to TOU-8 Subtransmission.
- h. 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 service or DA customers.
- 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.
- j. 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, and Lowe's Home Improvement Warehouses, Inc.
- k. 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 Company and San Diego Gas & Electric Company.
- 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. 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, Shell Oil Products US, THUMS Long Beach Company, Occidental Elk Hills, Inc., and Valero Refining Company California
- n. Solar Alliance is a non-profit organization with members throughout California and the country who want a rapid transition to a clean and renewable energy future.

2. Recitals

- a. In Phase 2 of SCE's 2009 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 March 4, 2008, SCE served its initial prepared testimony regarding marginal costs, revenue allocation and rate design in Application
 (A.) 08-03-002. SCE's A. 07-12-020, filed December 21, 2007, was

consolidated with A.08-03-002 on March 26, 2008. SCE updated its initial prepared testimony on June 27, 2008.

- c. In accordance with the Scoping Memo and Ruling of Assigned Commissioner, dated May 14, 2008, 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 12, 2008.
- d. DRA served its initial testimony on September 26, 2008. Interveners served their initial testimony on October 31, 2008.
- e. Continuing settlement discussions occurred among the interested parties after November 12, 2008.
- f. The Parties have evaluated the impacts of the various proposals in this consolidated proceeding for A.08-03-002 and A.07-12-020, desire to resolve all issues related to allocation of SCE's authorized revenue requirement, and have reached agreement as indicated in Paragraph 5 of this Agreement.

3. <u>Comparison Exhibit</u>

As required by Rule 12.1, 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.

4. **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. "BTUs" means British Thermal Units, which is commonly used as a measure of the energy capacity of natural gas.
- c. "Basic Charge" means the customer charge applied to customers in the Domestic Rate Group, as differentiated for single-family and multi-family residences.
- d. "DWR" means the California Department of Water Resources.
- e. "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.
- f. "FERC" means the Federal Energy Regulatory Commission.
- g. "Loss of Load Expectation" means the expectation that available generation capacity will be inadequate to supply customer demand at any given moment.
- h. "Marginal Cost" means the change in total cost due to a small change in the quantity produced or provided.
- "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.
- j. "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.
- k. "Rate Case Plan" means D. 89-01-040, as modified by D. 93-07-030 and D.07-07-004 for processing by the Commission of SCE rate cases.

- "Real Economic Carrying Charge" or RECC means a measure of the per dollar savings of deferring an investment one year.
- m. "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.
- n. "Settling Parties" means SCE, DRA, TURN, CFBF, AECA, ICP, EUF, CMTA, CLECA, FEA, CAL-SLA, BOMA, Solar Alliance, and EPUC,.
- o. "Subtransmission Voltage" means facilities at which electric power is taken or delivered, generally greater than 50 kV and less than 220 kV.
- p. "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.

5. Agreement

In consideration of the mutual obligations, covenants and conditions contained herein, the Settling Parties agree to the terms of this Agreement. Nothing in Paragraph 5 of this Agreement shall be deemed to constitute an admission or an acceptance by any Party of any fact, principle, or position contained herein. This Agreement is subject to the express limitation on precedent described in Paragraph 11. The Parties, by signing this Agreement, acknowledge that they pledge support for Commission approval and subsequent implementation of all the provisions of the Agreement.

a. Marginal Costs

This Agreement does not reflect approval or acceptance of any of the Parties' marginal cost proposals as the basis for the agreed-upon Phase 2 Revenue Allocation Agreement which is described in Paragraph 5.b with illustrative results provided in Appendix B. Except as otherwise expressly provided in this Agreement, the Settling Parties agree that it is reasonable to use the

marginal costs set forth below in Paragraphs 5.a.i, 5.a.ii, and 5.a.iii 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.

i. Generation Marginal Energy and Capacity Costs

Generation marginal energy costs incorporated in this Agreement shall be based on a forecast gas price of \$7.00 per million BTUs averaged over 36 months from January 2009 through December 2011. The hourly marginal energy costs derived from this gas price forecast using SCE's methodology set forth in Exhibit SCE-02 (updated) are averaged by TOU periods. Generation marginal capacity cost shall be 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, less the estimated value of energy rents obtained by CT energy sales, which yields a generation marginal capacity cost of \$114.10 per kW per year. This generation marginal capacity cost is allocated to TOU periods by the relative loss of load expectation measure. When the amount of the general plant loader is subtracted from this generation marginal capacity cost, a net value of \$108.00 per kW per year results. Unless modified through subsequent rate design settlement agreements applicable to specific rate groups, this net marginal capacity cost shall also be the basis for the rate credits provided for non-firm service, price response programs, and reliability programs. Generation marginal costs by season and time-of-use periods shall be as follows:

	Generation	Marginal Cos	t (2009\$)								
		Summer		Win	iter						
	On-Peak	Mid-Peak	Off-Peak								
On-Peak Mid-Peak Off-Peak Mid-Peak Off-Peal											
Energy Cost (¢/kWh)	7.27	6.05	4.60		5.95	4.50					
Annual 5.34 ¢/kWh											
CT Proxy (\$/kW-year):	79.98	23.39	1.03		9.24	0.46					
Annual \$114.10/kW-year											
Relative Loss of Load											
Expectation	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 \$7.00 per MM Btu. The CT proxy is based on a forecast installed cost of \$969/kW in 2009\$. These costs are forecast at the generator level.

ii. Marginal Customer Cost

For purposes of revenue allocation only, marginal customer costs are determined based on 50:50 ratio of SCE's RECC and DRA's NCO marginal customer cost recommendations and shall be as follows:

Rate Group	2009\$/customer-month
Domestic	9.83
GS-1	18.90
TC-1	15.09
GS-2	140.96
TOU-GS-3	331.57
TOU-8- Secondary	337.44
TOU-8- Primary	191.97
TOU-8-Subtransmission	1207.38
PA-1	56.83
PA-2	90.66
AG-TOU	147.62
TOU-PA-5	167.81
Street Lighting	15.75

iii. Marginal Distribution Capacity Cost

For purposes of revenue allocation only, marginal distribution costs shall be as follows:

Distribution Marginal Cost (2009\$)							
	System						
	Design Demand (\$/kW- year)						
Non-ISO Subtransmission (66 kV)	29						
Distribution (12 kV)	69						

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, 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 2009 GRC, SCE's FERC rate case (ER08-1343/1353), and other proceedings.

i. Mitigation of Impact of Revenue Allocation Changes

All of SCE's rate groups are expected to receive revenue requirement increases that will be reflected in rates over the period from December 2008 through June 2009. These revenue changes will have disparate impacts on different rate groups based on the functional System Average Percent Change (SAPC) methodology which applies to these revenue changes in accordance with the settlement agreement adopted in D.06-06-067 in Phase 2 of SCE's 2006 GRC. In order to avoid further litigation and to mitigate potentially adverse impacts on any particular rate group based on movement toward cost-based rates in this proceeding, the Settling Parties have agreed on how to allocate SCE's total revenue requirement to each rate group effective October 2009.

ii. Estimated Adjusted Consolidated Revenue Requirement

For the purpose of this Agreement, SCE has provided an estimated adjusted consolidated revenue requirement. This estimate was derived by accounting for certain one-time annual reductions in SCE's authorized

revenues for 2009. These reductions will no longer be reflected in SCE's authorized revenues by early 2010, and include the following: 1) The suspension of SCE's collection of the CSI revenue requirement in compliance with D.08-12-004; 2) the end of the one-year PBR refund period that was established by D.08-09-038; and 3) the refund of unspent CEC Renewables monies. In addition, SCE assumed that by the end of 2009, the payoff of the DA-CRS undercollection amount will have occurred, thereby resulting in adjustments to certain bundled service and DA revenues in accordance with D.06-07-030. For bundled-service customers, this estimated adjusted consolidated revenue requirement represents a system average percentage change (SAPC) increase of 13.4 percent from December 2008 rate levels. To develop the estimated rates that would be implemented on October 1, 2009 as a result of this Agreement, SCE reduced the estimated adjusted consolidated revenue requirement to incorporate the effect of these one-time revenue reductions in a manner consistent with the functional SAPC revenue allocations agreed to in Paragraph 5.b.v below. SCE also adjusted its generation revenue requirements to account for the CRS loan repayment from "Small" to "Large" bundled service customers triggered by the full recovery of the DA-CRS undercollection amount. Pursuant to D.06-07-030, these loan repayment adjustments were made in the same proportion as the loans were provided.

iii. Caps on Revenues Allocated to Rate Groups

As a result of the revenue allocation methods and marginal costs applied to SCE's CPUC-authorized revenue requirements, each rate group receives different outcomes relative to the system average percentage change. The Settling Parties agree that no rate group shall receive an increase of more than 2.75 percent above the system average percentage change based on SCE's adjusted consolidated revenue requirement. The undercollection of SCE's authorized revenues resulting from this capping

shall be allocated based on percentage of generation marginal cost revenues to the rate groups whose increases are not otherwise capped.

iv. Additional Capping of Street Light Rate Group Nonallocated Revenues

The Settling Parties agree that nonallocated revenues assigned to the Street Light rate group should be limited so that for the period from October 1, 2009 through September 30, 2012, *i.e.*, Phase 2 of SCE's 2012 GRC, the facilities-related charges that are established in accordance with the "Southern California Edison Company 2009 GRC, Phase 2 Street Light Rate Group Settlement Agreement" do not increase by more than 4.8 percent per year from the December 2008 level of such charges. Any revenue deficiency associated with the establishment of facilities-related charges for Street Light rate schedules in accordance with this limitation shall be recovered from all rate groups, with the deficiency allocated on the basis of distribution revenues.

v. Allocation of CPUC and FERC-Authorized Revenue Requirements

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 Paragraph 5.b.vii 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. Revenue changes and rates for DA customers based on the adjusted consolidated revenue requirement are also shown in Appendix B.

vi. Adjustments To Revenue Requirements

The levels of revenues and rates reflected in Appendix B are illustrative and are based on the adjusted consolidated revenue requirement of \$12,234 million described in Section 5.b.ii, above. To the extent the revenue requirements assumed to result from these CPUC or FERC proceedings change from this assumption, 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 subject to the agreed upon revenue caps. 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.

vii. Unbundled Revenue Requirements

Without effecting any change to the agreed-upon Phase 2 Revenue Allocation Agreement in Appendix B, to produce unbundled rates for rate design purposes in this proceeding and to provide a basis for implementing 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 5.a.iii of this Agreement, and based on the marginal customer costs listed in Paragraph 5.a.ii of this Agreement, 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 combined direct-access (DA) and bundled-service demand and number of customers.
- 2. Interruptible rate program credits (*e.g.* Base Interruptible Program, Summer Discount Plan, and Agricultural/Pumping-Interruptible) 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 Paragraph 5.b.iv of 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.

c. Generation Revenue Requirement

- The DWR Revenue Requirement, net of contribution by DA customers, shall be combined with SCE's other generation-related revenue requirements and shall be allocated to rate groups for recovery from bundledservice 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.
- 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.

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.

e. DA Cost Responsibility Surcharge

For the purpose of this Agreement, the DA CRS undercollection revenue responsibility is assumed to be fully recovered. This assumption also triggers the "small"/"large" loan repayment adopted in D.03-07-029 and authorized in

D.06-07-030. The full level of the 2009 DA CRS for DA customers is estimated to be 1.584 cents per kWh. Thus, the 2.7 cents per kWh cap no longer applies after the assumed full recovery of the DA CRS undercollection.

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. SCE's authorized revenue requirement for the California Solar Initiative (CSI) shall be allocated on the same SAP basis and shall be recovered on a cent per kWh basis in the PPP component of SCE's delivery charges.

h. 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.

i. Edison SmartConnect Cost Allocation

Edison SmartConnect costs shall be allocated as distribution costs.

viii. 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 Phase 2 of SCE's 2012 GRC proceeding is implemented shall be allocated according to the functional character of the revenue requirement change on an SAPC basis using the allocators set forth at page A-2 of Appendix A of Exhibit SCE-3 (updated), Summary of 2009 Revenue Allocators. 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 generation 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. To the extent necessary, based on "Southern California Edison Company 2009 GRC, Phase 2 Street Light Rate Group Settlement Agreement," streetlight facilities charges are capped until Phase 2 of SCE's 2012 GRC is implemented, the revenue deficiency shall be recovered from all rate groups as provided in Paragraph 5.b.iv.

6. 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, but no earlier than October 1, 2009.

7. <u>Incorporation of Complete Agreement</u>

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 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.

8. Signature Date

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

9. 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.

10. 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.

11. Non Precedent

Consistent with Rule 12.5 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 or unless the Commission expressly provides otherwise.

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

13. 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.

14. Effect Of Subject Headings

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

15. 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.

16. 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.

SOUTHERN CALIFORNIA EDISON COMPANY

By: /s/ Bruce Reed

Title: Senior Attorney Date: 1/7/2009

DIVISION OF RATEPAYER ADVOCATES

By: /s/ Dana Appling

Title: Director Date: 1/7/2009

THE UTILITY REFORM NETWORK

By: /s/ Hayley Goodson

Title: Staff Attorney Date: 1/7/2009

CALIFORNIA FARM BUREAU FEDERATION

By: /s/ Ron Liebert

Title: Associate Counsel Date: 12/24/2008

AGRICULTURAL ENERGY CONSUMERS ASSOCIATION

By: /s/ Dan Geis

Title: Assistant Executive Director Date: 1/8/2009

FEDERAL EXECUTIVE AGENCIES

By: /s/ Norman Furuta

Title: Associate Counsel Date: 1/8/2009

CALIFORNIA MANUFACTURERS AND TECHNOLOGY ASSOCIATION

By: /s/ Keith R. McCrea

Title: Attorney Date: 1/9/2009

ENERGY USERS FORUM

By: /s/ Carolyn Kehrein

Title: Consultant Date: 1/7/2009

CALIFORNIA LARGE ENERGY CONSUMERS ASSOCIATION

By: /s/ William Booth

Title: Attorney Date: 1/8/2009

INDICATED COMMERCIAL PARTIES

By: /s/ Randall W. Keen

Manatt, Phelps & Phillips, LLP

Title: Attorneys for Date: 1/8/2009

Indicated Commercial Parties

BOMA

By: /s/ B.F. Roberts

Title: President, Economic Sciences Corp. Date: 1/8/2009

CALIFORNIA CITY-COUNTY STREET LIGHT ASSOCIATION

By: /s/ Reed V. Schmidt

Title: Energy Consultant Date: 1/8/2009

SOLAR ALLIANCE

By: /s/ R. Thomas Beach

Title: Consultant Date: 1/9/2009

ENERGY PRODUCERS AND USERS COALITION

By: /s/ Nora Sheriff

Title: Counsel Date: 1/8/2009

Appendix A

Comparison of SCE and DRA Revenue Allocation Proposals

Comparison of SCE, DRA And Settlement Revenue Allocation Proposals Bundled Service Rate Comparison Illustrative Rates (¢/kWh)

	December 2008 Average Rates	SCE E Propo (Uncar Proposed Rate	osal	DRA Pro (Capp Proposed Rate	Se	Proposed Settlement Proposed Percent Rate Change		
Total Domestic	14.91	17.37	16.5%	16.71	12.0%	17.3	32	16.1%
GS-1 TC-1 GS-2 TOU-GS-2 Total LSMP	16.93 15.14 14.51 13.22 14.56	17.82 20.05 15.51 13.41 15.34	5.3% 32.4% 6.9% 1.4% 5.3%	18.07 16.96 16.00 14.19	6.7% 12.0% 10.3% 7.4% 8.9%	18.7 17.5 16.8 14.3	58 35 35	10.6% 16.1% 16.1% 8.6% 13.2%
TOU-8-Sec TOU-8-Pri TOU-8-Sub Total Large Power	12.37 11.70 7.63 10.79	12.65 11.62 8.85 11.25	2.3% -0.7% 16.0% 4.3%	13.33 12.34 8.55 11.65	7.8% 5.4% 12.0% 8.0%	13.6 12.5 8.8 11.8	51 36	10.1% 6.8% 16.1% 10.1%
PA-1 PA-2 AG-TOU TOU-PA-5 Total Ag &	18.60 13.01 9.71 9.51	20.01 14.45 12.43 12.59	7.6% 11.1% 28.0% 32.5%	18.74 14.51 10.88 10.65	0.7% 11.5% 12.0% 12.0%	19.8 14.8 11.2 11.0	30 27 04	6.9% 13.8% 16.1% 16.1%
Pumping Total Street Lighting Total System	11.19 <u>18.63</u> 13.73	21.31 15.13	22.5% 14.4% 10.2%	12.26 20.87	9.5%	20.6	66	13.3%

Note: The settlement revenue allocation depicted in this comparison incorporates more recent revenue requirement estimates and therefore cannot be directly compared to the SCE and DRA proposals. This comparison shows the initial litigation positions of SCE and DRA along with the proposed settlement position. DRA proposed rates are derived from DRA's testimony.

Appendix B

Phase 2 Revenue Allocation Agreement

Phase 2 Revenue Allocation Agreement

Bundled-Service Rate Groups

Illustrative Rates

Bundled Service Average Rates (¢/kWh)

			ı i											
				Oct. 1,	Proposed							Percent of Sys	stem Average	
	Dec. 2008	Jan. 2009	June 2009	2009	Settlement		Relative Percentage Changes					Ra	Rate	
	A	В	С	D	E	B/A	C/A	D/A	E/A	D/C	E/D	A	E	
Total Domestic	14.9	14.8	16.1	16.4	17.3	-0.8%	8.1%	9.8%	16.1%	1.6%	5.7%	109%	111%	
GS-1	16.9	16.8	18.1	17.7	18.7	-1.1%	6.7%	4.7%	10.6%	-1.8%	5.6%	123%	120%	
TC-1	15.1	14.5	15.8	16.5	17.6	-4.2%	4.1%	9.1%	16.1%	4.9%	6.4%	110%	113%	
GS-2	14.5	14.3	15.7	15.9	16.9	-1.3%	8.4%	9.9%	16.1%	1.4%	5.7%	106%	108%	
TOU-GS-3	13.2	12.8	14.4	13.5	14.3	-2.9%	8.6%	1.9%	8.6%	-6.2%	6.6%	96%	92%	
Total LSMP	14.6	14.4	15.8	15.6	16.5	-1.4%	8.2%	6.9%	13.2%	-1.2%	5.9%	106%	106%	
TOU-8-Sec	12.4	12.2	13.0	12.8	13.6	-1.3%	5.3%	3.6%	10.1%	-1.6%	6.3%	90%	88%	
TOU-8-Pri	11.7	11.5	12.3	11.7	12.5	-2.1%	5.3%	0.1%	6.8%	-4.9%	6.7%	85%	80%	
TOU-8-Sub	7.6	7.5	7.9	8.3	8.9	-1.1%	3.0%	8.2%	16.1%	5.0%	7.3%	56%	57%	
Total Large Power	10.8	10.8	11.3	11.1	11.9	0.2%	4.5%	3.2%	10.1%	-1.2%	6.6%	79%	76%	
PA-1	18.6	18.4	19.6	18.8	19.9	-0.9%	5.2%	1.0%	6.9%	-4.0%	5.8%	135%	128%	
PA-2	13.0	12.8	13.8	14.0	14.8	-1.4%	5.8%	7.2%	13.8%	1.4%	6.1%	95%	95%	
AG-TOU	9.7	9.1	10.3	10.5	11.3	-6.0%	6.0%	8.3%	16.1%	2.1%	7.3%	71%	72%	
TOU-PA-5	9.5	9.4	9.7	10.3	11.0	-1.3%	2.2%	8.7%	16.1%	6.3%	6.8%	69%	71%	
Total Ag.&Pumping	11.2	10.9	11.7	11.9	12.7	-2.3%	4.3%	6.1%	13.3%	1.7%	6.7%	82%	81%	
Total Street Lighting	18.6	18.5	19.7	19.6	20.7	-0.7%	5.9%	5.3%	10.9%	-0.5%	5.3%	136%	133%	
Total System	13.7	13.6	14.7	14.7	15.6	-1.0%	6.9%	7.0%	13.4%	0.1%	6.0%	100%	100%	

Column A: Actual rates effective December 2008.

Column B: Actual rates effective January 1, 2009 based on revenue requirement changes, including DWR Power Charge, DWR Bond Charge, and Transmission balancing accounts, implemented on a functional SAPC basis.

Column C: Forecast rates based on actual rates in Column B, plus assumed revenue requirement increases allocated on a functional SAPC basis on or before June 1, 2009 for the following applications: Phase 1 SCE 2009 GRC (alternate proposed decision), December 2008 ERRA Trigger, SCE's FERC GRC, 2009-2011 Energy Efficiency and Demand Response Programs. Forecast rates also reflect various one-time revenue adjustments that occur in 2009, including the suspension of CSI revenue collection, PBR OII refund, PG&E DWR Accelerated Payment, and CEC renewable energy refund.

Column D: Forecast rates effective October 1, 2009 based on same total revenue requirement assumed for Column C, adjusted (Paragraph 5.b.ii) to achieve the same effective allocation of revenues to each rate group as shown in Column E.

Column E: Forecast rates at end of year 2009 based on estimated adjusted revenue requirement (Paragraph 5.b.ii), excluding one-time charges or refunds made in 2009 (suspension of CSI revenue collection, PBR OII refund, CEC renewable energy refund, ERRA trigger revenues, and the repayment of the DA-CRS undercollection) and the results of applying the settlement values for marginal costs (Paragraph 5.a.i-iii), functional SAPC revenue allocations (Paragraphs 5.b.v, 5.b.vii) with a 2.75 % cap on revenues allocated to any one rate group (Paragraph 5.b.iii) and a cap on increases to Street Light facilities charges (Paragraph 5.b.iv). Does not reflect revenue changes for the 2010 ERRA forecast or for 2010 attrition year (2009 GRC).

Phase 2 Revenue Allocation Agreement Direct Access Rate Groups Illustrative Settlement Rates

	Rates Effective December 2008 (\$/kWh)	Settlement Proposal Rates (¢/kWh)	Settlement Percent Change
Residential	0.08769	0.08701	-0.8%
Lighting, Small and Medium Power			
GS-1	0.08226	0.09274	12.7%
TC-1	0.08104	0.09547	17.8%
GS-2	0.06239	0.06118	-1.9%
TOU-GS-3	0.06426	0.06082	-5.4%
Group Total	0.06372	0.06160	-3.3%
Large Power			
TOU-8-SEC	0.06009	0.05379	-10.5%
TOU-8-PRI	0.05601	0.04861	-13.2%
TOU-8-SUB	0.03788	0.03037	-19.8%
Group Total	0.04878	0.04189	-14.1%
Agricultural & Pumping			
PA-1	0.06040	0.06557	8.6%
PA-2	0.06015	0.05056	-15.9%
TOU-AG	0.04617	0.04120	-10.8%
TOU-PA-5	0.06552	0.05391	-17.7%
Group Total	0.04985	0.04408	-11.6%
Street & Area Lighting	0.05923	0.05636	-4.8%
System Total	0.05278	0.04817	-8.7%
			

Phase 2 Revenue Allocation Agreement Proposed Bundled Service Revenues Adjusted Consolidated Revenue Requirement (\$MM)

(Illustrative)

				Total	URG	DWR	Total	Total
	Trans	Dist.	Other	Delivery	Gen.	Power	Gen.	Bundled
Total Residential	230.9	1,673.4	350.3	2,254.6	2,085.5	679.0	2,764.6	5,019.2
CC 1	40.7	202.0	60.4	402.7	202 7	4444	E07.0	044.5
GS-1	42.7	292.9	68.1	403.7	393.7	114.1	507.8	911.5
TC-1	0.3	4.7	0.7	5.8	2.8	1.3	4.1	9.9
GS-2	111.4	722.9	184.1	1,018.4	1,057.5	335.3	1,392.8	2,411.3
TOU-GS-3	58.6	303.5	93.3	455.4	458.3	178.3	636.6	1,092.0
Total LSMP	213.0	1,324.0	346.3	1,883.3	1,912.4	629.1	2,541.4	4,424.7
TOU-8-Sec	51.8	230.0	94.0	375.8	531.8	188.6	720.3	1,096.2
TOU-8-Pri	29.3	120.0	58.2	207.5	312.5	119.9	432.4	640.0
TOU-8-Sub	33.8	38.6	53.3	125.6	260.2	123.9	384.1	509.7
Total Large Power	114.9	388.6	205.4	709.0	1,104.6	432.4	1,536.9	2,245.9
PA-1	2.7	30.2	5.8	38.7	30.5	9.2	39.8	78.4
PA-2	1.9	14.0	4.3	20.2	23.8	8.3	32.1	52.3
AG-TOU	5.8	47.6	15.7	69.1	64.8	35.1	99.9	169.0
TOU-PA-5	5.1	22.7	9.3	37.1	41.7	21.2	63.0	100.0
Total Ag.&Pump.	15.5	114.5	35.1	165.0	160.9	73.9	234.7	399.7
Total Street Lights	2.5	90.0	10.3	102.8	25.3	16.4	41.7	144.5
SYSTEM	576.8	3,590.5	947.4	5,114.7	5,288.6	1,830.7	7,119.3	12,234.0

(END OF ATTACHMENT B)

ATTACHMENT C

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Southern California Edison)	
Company (U 338-E) To Establish Marginal)	Application 08-03-002
Costs, Allocate Revenues, And Design Rates)	(Filed March 4, 2008)
)	
In the Matter of the Application of Southern)	
California Edison Company (U 338-E) for)	Application 07-12-020
Authority to Make Various Electric Rate Design)	(Filed December 21, 2007)
Changes)	

2009 GRC PHASE 2 RESIDENTIAL AND SMALL COMMERCIAL RATE DESIGN SETTLEMENT AGREEMENT

Dated: January 20, 2009

Paragraph	Title	Page
1.	Parties	1
2.	Recitals	2
3.	Definitions	2
4.	Agreement	4
5.	Implementation of Agreement	11
6.	Incorporation of Complete Agreement	11
7.	Signature Date	11
8.	Regulatory Approval.	11
9.	Compromise Of Disputed Claims	12
10.	Non Precedent	12
11.	Previous Communications	12
12.	Non Waiver	12
13.	Effect Of Subject Headings	13
14.	Governing Law	13
15.	Number Of Originals	13
Appen	dix A - Illustrative Rates for Residential and Small Commercial Rate Schedules	
Appen	dix B - Monthly and Annual Reports on Arrearages and Shutoffs	
Appen	dix C - Baseline Allocations	

2009 GRC PHASE 2 RESIDENTIAL AND SMALL COMMERCIAL RATE DESIGN SETTLEMENT AGREEMENT

This Phase 2 Residential and Small Commercial Rate Design Settlement Agreement (Agreement or Settlement Agreement) is entered into by 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); the Solar Alliance, and the Western Manufactured Housing Community Association (WMA) (referred to hereinafter collectively as Parties or Settling Parties or individually as Party).

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

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

2. Recitals

- a. In Phase 2 of SCE's 2009 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 March 4, 2008, SCE served its initial prepared testimony regarding marginal costs, revenue allocation and rate design in Application 08-03-002.
 SCE updated its initial showing on June 27, 2008.
- c. In accordance with the Scoping Memo and Ruling of Assigned Commissioner, dated May 14, 2008, 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 12, 2008.
- d. DRA served its initial testimony on September 26, 2008. Interveners served their initial testimony on October 31, 2008.
- e. Continuing settlement discussions occurred among the interested parties after November 12, 2008.
- f. The Parties have evaluated the impacts of the various proposals in this consolidated proceeding for A.08-03-002 and A.07-12-020 and desire to resolve all issues related to rate design for the Residential and Small Commercial Rate Groups as indicated in Paragraph 4 of this Agreement.

3. Definitions

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

- a. "AB1X" refers to the special legislation enacted in 2001 which capped residential rates for usage up to 130% of the then-authorized baseline allowances.
- b. "Agreement" shall have the meaning given to such term in the introductory paragraph hereof.
- c. "Basic Charge" means the customer charge applied to customers in the Residential Rate Group, as differentiated for single-family and multifamily residences.
- d. "CARE" means the California Alternate Rates for Energy program which provides customers meeting a certain household income criteria a discount from SCE's otherwise applicable residential rates.
- e. "Customer Charge" means the dollar per month charges applicable to certain Small Commercial Rate Group rate schedules.
- f. "CSI" means the California Solar Initiative, and the revenue requirement associated with the CSI that SCE has been authorized to recover from SCE ratepayers.
- g. "DWR" means the California Department of Water Resources.
- h. "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.
- i. "Functional SAPC Allocation" means allocation of SCE's revenue requirement to each of SCE's rate groups based on the system average percentage change for the particular function, *e.g.*, distribution or generation.

- j. "PPP" means Public Purpose Programs and the revenue requirement associated with Public Purpose Programs such as the revenue requirement that provides the discount to CARE customers.
- k. "Residential Rate Group" means the following rate schedules: Schedule D, Schedule D-APS, Schedule D-APS-E, Schedule D-CARE, Schedule D-FERA, Schedule DMS-1, Schedule DMS-2, Schedule DMS-3, Schedule MB-E, Schedule TOU-D-T, Schedule TOU-D-1, Schedule TOU-D-2, Schedule TOU-EV, TOU-EV-1, and Schedule TOU-TEV.
- 1. "SAP" means system average percentage.
- m. "Settling Parties" means SCE, DRA, TURN, Solar Alliance, and WMA.
- n. "Small Commercial Rate Group" means the following rate schedules: Schedule GS-1, Schedule TOU-GS-1, and Schedule TOU-EV-3.
- 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.

4. Agreement

In consideration of the mutual obligations, covenants and conditions contained herein, the Settling 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 Paragraph 10 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.

a. Illustrative Rates

The Settling Parties agree that the results of the rate design process illustrated by the rate schedules in Appendix A to this Agreement are reasonable and should be adopted by the Commission. These rates are based on SCE's estimated adjusted consolidated revenue requirement and shall be adjusted consistent with the terms of this Agreement and the Phase 2 Revenue Allocation Settlement Agreement¹ to reflect SCE's actual total system revenue requirement when this Agreement is implemented.

b. Pricing Agreement

i. Tiered Rate Structure

Energy charges for SCE's Schedule D, and other comparably-structured Residential Rate Group 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.

ii. Basic Charge and Energy Rates For Tiers 1 and 2

The energy rates for usage up to 130% of the baseline allocation (Tier 1 and Tier 2) shall not be increased above the levels effective on February 1, 2001 except to the extent recovery of CSI revenues were authorized for recovery in Tier 1 and Tier 2 energy rates by Resolution E-4167. However, CSI revenues shall be allocated on the same basis as other PPP revenues on an SAP basis and recovered on a cent per kWh basis as is the PPP component of SCE's delivery charges instead of the allocation method adopted in Resolution E-4167. There shall be no increase made to the Basic Charges on residential rate schedules that were effective as of December 2008. The Basic Charge for all Residential Rate Group TOU options shall be set equal to the single-family Basic Charge effective as of December 2008.

- 5 -

-

The Phase 2 Revenue Allocation Settlement Agreement was filed on January 9, 2009.

iii. Energy Rates For Tiers 3 – 5

For Schedule D, revenue changes allocated to residential customers shall be reflected in the rates established for Tiers 3, 4, and 5. SCE shall establish rates so that there is a differential of two and one-half cents per kWh between the rates for Tier 3 and Tier 4, and between the rates for Tier 4 and Tier 5. However, if legislation modifying the residential rate protective provisions of AB1X is enacted, which allows at least a three percent annual increase in Schedule D Tier 1 and Tier 2 rates, SCE shall establish rates at the next regularly-scheduled rate change so that there is a three and one-half cent per kWh differential between the rates for Tier 3 and Tier 4, and between the rates for Tier 4 and Tier 5.

iv. Baseline Zone Modification

In accordance with SCE's Exhibit SCE-4 (updated), dated June 27, 2008, SCE's six baseline zones shall be revised to align with the nine climate zones established by the California Energy Commission (CEC) to provide a more accurate basis for establishing baseline allocations. Customers currently residing in SCE's existing baseline zone 15 shall retain their currently designated baseline zone.

v. Baseline Allocation

SCE shall update its baseline allowances to reflect current usage levels and reduce baseline allocation percentages for each baseline zone to 50 percent of the average aggregate customer usage. However, if legislation modifying the residential rate protective provisions of AB1X is enacted, which allows at least a three percent annual increase in Schedule D Tier 1 and Tier 2 rates, SCE shall use then-current usage levels and establish rates at the next regularly-scheduled rate change with the baseline allocation percentages for each baseline zone set at 55 percent of the average aggregate customer usage. SCE has excluded the impact of seasonal residents from the determination of baseline allocations for zones 15 and 16. The baseline kilowatt-hour allowance for each revised baseline zone based on the CEC climate zones shall not be less than the allowance in effect in the baseline zones that existed on February 1, 2001.

vi. **D-CARE Structure**

Energy charges for Schedule D-CARE shall reflect three different energy charges, which increase from Tier 1 to Tier 2 and to Tier 3. The Schedule D-CARE Tier 3 rate shall be established at a level that provides a discount of 20 percent from the Schedule D Tier 3 rate level subject to a ceiling of 20 cents per kilowatt hour (with any additional CARE surcharge revenue deficiency resulting from the rate ceiling recovered solely from the Residential Rate Group) after excluding the CARE surcharge component of the Public Purpose Program charge, the DWR Bond Charge, and any applicable CSI rate component that otherwise applies to the Tier 3 rate for Schedule D.

vii. **D-FERA Structure**

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

viii. Demand Response Rates (Summer Discount Plan (SDP), Peak Time Rebate (PTR), Programmable Communicating Thermostat (PCT), and Critical Peak Pricing (CPP))

SCE's demand response proposals and eligibility criteria set forth in Exhibit SCE-4 (updated) for the SDP, PTR, PCT, and CPP shall be adopted with the exception that the technology-enabled incentive for the PTR and PCT programs shall be \$1.25/kWh for the three-year cycle of SCE's 2009 GRC. SCE will make good faith efforts to align the trigger mechanism for the SDP (Schedules D-APS, D-APS-E, and GS-APS) with the trigger mechanism for the Base Interruptible Program (BIP) for nonresidential customers. The basis for the SDP and CPP rate designs shall be consistent with SCE's proposed capacity valuation method. To the extent that "free-rider ship" credits are quantified for the PTR program, the revenue credits associated with "free rider ship" shall be recovered from the Residential Rate Group. SCE intends to conduct a study to estimate the level of free-rider ship credits for the PTR program, and to make a future request to recover this revenue deficiency from residential customers given that the revenue deficiency would be

otherwise recovered from all ratepayers through the Energy Resource Recovery Account (ERRA) balancing account.

ix. TOU-D Schedules

Schedules TOU-D-1 and TOU-D-2 will be closed to new customers but existing customers shall be grandfathered on these rate schedules for the three-year term of SCE's 2009 GRC cycle. Schedule TOU-D-T shall be established as a 2-tiered TOU rate structure with the same TOU periods as the current TOU schedules. The lower rate tier of this new TOU structure will be designed to be revenue neutral to the otherwise applicable tariff's Tier 1 and Tier 2 rates, *e.g.*, Schedule D or Schedule D-CARE, while the higher tier will be designed to be revenue neutral to the otherwise applicable tariff's Tier 3 through Tier 5 rates. This structure will apply to Schedules TOU-D-T and TOU-TEV. No incremental TOU meter charges will apply to these four rate schedules.

x. Schedule TOU-TEV

Schedule TOU-EV shall be offered as a new rate option for customers who prefer single meter service for a primary residence with an electric vehicle load. Schedule TOU-TEV shall have on-peak, off-peak and super-off peak TOU periods. The on-peak period shall be between 10:00 a.m. and 6:00 p.m. all year except holidays. The super off-peak period shall be between midnight and 6:00 a.m. all year, every day. The off-peak period will comprise the balance of the hours. Energy pricing for Schedule TOU-TEV shall provide discounted super off-peak charging rates, subject to a floor price defined as the sum of SCE's marginal generation and distribution costs plus nonbypassable charges.

xi. Schedule TOU-EV-1

Schedule TOU-EV-1 shall be modified to provide discounted off-peak charging rates, subject to a floor price defined as the sum of SCE's marginal generation and distribution costs plus nonbypassable charges.

TOU meter charges will be removed from this schedule. In order to make this revision available earlier than October 1, 2009, SCE shall implement

the modified Schedule TOU-EV-1 as soon as practicable after Commission approval of this Settlement Agreement.

xii. Submetering Discount

The discount provided to customers who provide submetered electric service and who are served on Schedule DMS-2 shall be \$0.148 per space per day. This value reflects a cost-of-service discount of \$0.34 decreased by a diversity adjustment of \$0.17 per space per day, and decreased by a Basic Charge adjustment of \$0.022 per space per day. The diversity adjustments for Schedules DM and DMS-1 shall also be \$0.17 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.

WMA has recommended changes in how the baseline allowances are applied during the Schedule DMS-2 bill calculation. SCE will identify the billing system changes and associated costs required to implement WMA's recommendations. If feasible, SCE will implement WMA's recommended changes to the DMS-2 billing calculation, and will thereafter decrease the diversity adjustment by two cents to \$0.15 per space per day. The Settling Parties agree that the billing calculation change and the two cent decrease in the diversity adjustment will roughly offset each other, such that total bills for Schedule DMS-2 customers will not change.

xiii. Conservation Incentive Adjustment

As SCE proposed in Exhibit SCE-4 (updated), in accordance with the Conservation Incentive Adjustment proposal, SCE shall restructure its residential rates to reflect the rate differentials between tiers in the delivery component of those rates instead of the generation component.

xiv. Medical Baseline

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

xv. Schedules DE and DS

Schedules DE (employee/retiree discount) and DS (optional seasonal pricing) shall be retained with the existing eligibility provisions and as currently structured.

c. Reporting of Residential Arrearages and Shutoffs

For the period beginning January 2009 and ending December 2011, SCE shall provide to the Director of the Commission's Energy Division monthly and annual reports listed and at the times specified in Appendix B.

d. GS-1 Rate Group

i. Customer Charges and Seasonal Rates

Effective with the implementation of this Settlement Agreement, SCE shall not increase the Schedule GS-1 Customer Charge and the Schedule TOU-GS-1 Customer Charge from their then-current levels on October 1, 2009. Changes to the Schedule GS-1 and Schedule TOU-GS-1 Customer Charges after October 1, 2009 shall be based on Functional SAPC Allocation of distribution revenue changes. SCE will implement its proposed seasonally-differentiated energy charge for Schedule GS-1 reflecting the seasonal differences in marginal energy and capacity costs.

ii. Schedule TOU-GS-1

SCE's proposals for Schedule TOU-GS-1 contained in Exhibit SCE-04 (Updated), dated June 27, 2008, shall be adopted, except for SCE's proposed increase to the Customer Charge. The proposed Schedule TOU-GS-1 meter charge shall be eliminated.

iii. Schedule TOU-EV-3

Schedule TOU-EV-3 off-peak energy charges will provide discounted off-peak charging rates, subject to a floor price defined as the sum of SCE's marginal generation and distribution costs plus nonbypassable charges as defined by D.07-11-052. On-peak energy charges will be set consistent with TOU-GS-1 on-peak energy charges but will reflect the different time-period definitions offered for the charging of commercial electric vehicles and incremental revenue recovery associated with the provided off-peak discount. Effective with the implementation of this Settlement

Agreement, SCE shall not increase the Schedule TOU-EV-3 Customer Charge from its then-current level on October 1, 2009. Changes to the Schedule TOU-EV-3 Customer Charge after October 1, 2009 shall be based on Functional SAPC Allocation of distribution revenues. TOU meter charges shall be removed from Schedule TOU-EV-3.

5. <u>Implementation of Agreement</u>

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.

6. <u>Incorporation of Complete Agreement</u>

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 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.

7. <u>Signature Date</u>

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

8. 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.

9. 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.

10. Non Precedent

Consistent with Rule 12.5 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 or unless the Commission expressly provides otherwise.

11. <u>Previous Communications</u>

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

12. 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.

13. Effect Of Subject Headings

Subject headings in this Agreement are inserted for convenience only, and shall

not be construed as interpretations of the text.

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.

15. 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.

SOUTHERN CALIFORNIA EDISON COMPANY

By: /s/ Bruce A. Reed

Title: Senior Attorney Date: January 23, 2009

DIVISION OF RATEPAYER ADVOCATES

By: /s/ Dana Appling

Title: Director Date: January 23, 2009

THE UTILITY REFORM NETWORK

By: /s/ Hayley Goodson

Title: Staff Attorney Date: January 21, 2009

- 13 -

Solar Alliance

By: /s/ Tom Beach

Title: Director of Programs Date: January 23, 2009

WESTERN MANUFACTURED HOUSING COMMUNITY ASSOCIATION

By: /s/ Edward G. Poole

Title: Counsel Date: January 21, 2009

III	ustrative Rate	s for Residentia	Appendix A I and Small Com	nmercial Rate So	chedules
Ill	ustrative Rate	s for Residentia	Appendix A l and Small Com	imercial Rate So	chedules
Ill	ustrative Rate	s for Residentia	Appendix A l and Small Com	imercial Rate So	chedules
111	ustrative Rate	s for Residentia	Appendix A l and Small Com	nmercial Rate So	chedules
Ill	ustrative Rate	s for Residentia	Appendix A l and Small Com	amercial Rate So	chedules
Ill	ustrative Rate	s for Residentia	Appendix A l and Small Com	amercial Rate So	chedules

		Γ									
		Effec	Rates tive December	2008	R	ased on Es	Settlement Rate stimated Adjust	s ed Revenue			
		Effec	Aive December	2008		4554 611 25					1
	dential rates based on seven cent Tier 3 - Tier 5	1									ı
	and baseline allocations set at 55% of average	1							,	Í	1
	sage by CEC climate zone. End of year 2009 revenue				}					Total Rate	
	at as specified in Paragraph 5.b.ii of Phase 2 Revenue	- ·	ایرا	mI.D	5	-1:	Generation	Total Rate		Change	l
	Settlement Agreement,	Delivery	Generation	Total Rate	<u> </u>	elivery	Generation	Total Kate		Change	ı
р											
	Energy Charge- \$/kWh	0.07517	0,04861	0,12078		0.02405	0.09571	0.11976		-0.85%	
	Baseline - Summer	0,07217 0,07217	0.04861	0.12078		0.02405	0.09571	0.11976		-0.85%	
	- Winter	0.07217	0.04861	0.12078		0.02403	0.09571	0,13909		-0.73%	
	101% - 130% of Baseline - Summer - Winter	0.07217	0.06794	0,14011		0.04338	0.09571	0,13909		-0.73%	
	- whiter	0.07217	0.13559	0.20776		0.18230	0,09571	0,27801		33.81%	5
	- Winter	0.07217	0.13559	0.20776		0.18230	0.09571	0.27801		33.81%	á
	200% - 300% of Baseline - Summer	0.07217	0.17059	0.24276		0.21730	0.09571	0.31301		28,94%	Ď
	- Winter	0.07217	0,17059	0.24276		0,21730	0.09571	0.31301		28.94%	ò
	Over 300% of Baseline	0.07217	0,20559	0.27776		0.25230	0.09571	0.34801		25.29%	ò
	- Winter	0.07217	0.20559	0.27776		0.25230	0.09571	0.34801		25.29%	ó
	" Hitter	0.01=11									
	Basic Charge - \$/day					-					
	Single-Family Residence	0.029	0.000	0.029		0.029		0.029		0.00%	
	Multi-Family Residence	0.022	0.000	0.022		0.022		0.022		0.00%	ó
	Minimum Charge - \$/day										
	Single Family Residence	0.059	0,000	0.059		0.059		0.059		0.00%	
	Multi-Family Residence	0.044	0.000	0.044		0.044		0.044		0.00%	ò
D-CARE											
	Energy Charge - \$/kWh			0.00522		(0.01078)	0.09571	0.08533		0.00%	4
	Baseline - Summer	0.03672	0.04861	0.08533	•	(0.01038)		0.08533		0.00%	
	- Winter	0.03672	0.04861	0.08533 0.10668		0.01036)	0.09571	0.10668		0.00%	
	101% - 130% of Baseline - Summer - Winter	0,03874 0,03874	0.06794 0.06794	0.10668		0.01097	0.09571	0.10668		0.00%	
	131% - 200% of Baseline - Summer	0.02301	0.13559	0.15860		0.10429	0.09571	0,20000		26.10%	6
	- Winter	0.02301	0.13559	0.15860		0.10429	0.09571	0,20000		26.10%	6
	200% - 300% of Baseline - Summer	(0.01199)		0.15860		0.10429	0.09571	0.20000		26.10%	6
	- Winter	(0.01199)		0.15860		0.10429	0.09571	0.20000		26.109	6
	Over 300% of Baseline	(0.04699)		0.15860		0.10429	0.09571	0.20000		26.109	6
	- Winter	(0.04699)		0.15860		0.10429	0.09571	0.20000		26.109	6
		, ,									
	Basic Charge - \$/day										
	Single-Family Residence	0.023	0.000	0.023		0.023		0.023		0.009	
	Multi-Family Residence	0.017	0.000	0.017		0.017	7	0.017		0.009	6
	Minimum Charge - \$/day									0.000	.,
	Single Family Residence	0.047	0.000	0.047		0.047		0.047		0.009	
	Multi-Family Residence	0.034	0.000	0.034		0.034	1	0.034		0.00	/0
D-APS											
	Air Conditioning Cycling Credit - \$\font{\text{ton/summer season day}}										
	· · · · · · · · · · · · · · · · · · ·	(0.05)	0,00	(0.05	١.	(0.04)	(0.04)	30.00	%
	50% Cycling 67% Cycling	(0.03)	•	(0.10	•	(0.07	•	(0.07		27.00	%
	100% Cycling	(0.18)		(0.18		(0.36		(0.36)	-98.89	%
	100/0 0/0		,		•	•					
D-APS-E											
	Air Conditioning Cycling										
	Credit - S/ton/summer season day									60.00	n/
	50% Cycling	(0.10)		(0.10		(0.04		(0.04			
	67% Cycling	(0.20)		(0.20		(0.08		(0.08		59.00 -13.61	
	100% Cycling	(0.36) 0,00	(0.36)	(0.41)	(0.41	,	-13.01	70
DE		100.00				100.0	۸	100.00			
	Discount - %	100.00				100.0	·	100.00			
n pen i											
D-FERA	Energy Charge SAWA										
	Energy Charge- \$/kWh Baseline - Summer	0.06947	0.04861	0.11808	3	0.0223	7 0.0957	0,11808		0.00	%
	- Winter	0.06947		0.11808		0.0223			i	0.00	
	101% - 130% of Baseline - Summer	0.06947				0.0417	0.0957	0,13741		0.00	1%

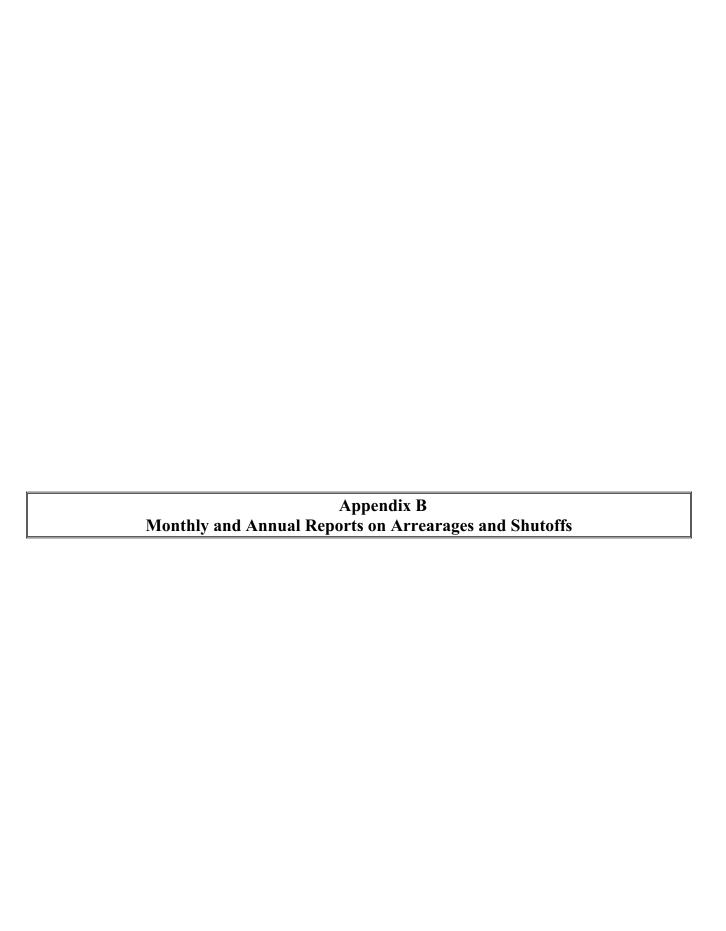
			F	Datas		1		ettlement Rate	e		
			Effec	Rates tive December	2008		Based on Es	timated Adjust	ed Revenue		
Mater Bosi	idential rates based on seven c	ent Tier 3 - Tier 5				1					
	l and baseline allocations set a		1								-
	usage by CEC climate zone. E					1	1				
	nt as specified in Paragraph 5.1									Т	otal Rate
	Settlement Agreement.	5.11 01 1 Hago 2 100 vollab	Delivery	Generation	Total Rate		Delivery	Generation	Total Rate		Change
Allocation	Settlement Agreement.	- Winter	0.06947	0,06794	0.13741	•	0.04170	0.09571	0,13741		0.00%
	131% - 2009	% of Baseline - Summer	0.06947	0.06794	0.13741		0.04170	0.09571	0.13741		0,00%
	20170 2007	- Winter	0.06947	0.06794	0.13741		0.04170	0.09571	0.13741		0.00%
	200% - 300%	% of Baseline - Summer	0.06947	0.17059	0.24006		0.21562	0.09571	0.31133		29.69%
		- Winter	0.06947	0.17059	0.24006		0.21562	0.09571	0.31133		29.69%
		Over 300% of Baseline	0.06947	0.20559	0.27506		0.25062	0.09571	0.34633		25.91%
		- Winter	0,06947	0.20559	0.27506		0.25062	0.09571	0.34633		25.91%
	Basic Charge - \$/day										0.000/
		Single-Family Residence	0.029	0.000	0.029		0,029		0.029		0,00%
		Multi-Family Residence	0.022	0.000	0.022		0.022		0.022		0.00%
	Minimum Charge - \$/day								0.050		0.00%
		Single Family Residence	0.059	0.000	0.059		0.059		0.059		0.00%
		Multi-Family Residence	0,044	0,000	0.044		0.044		0.044		0,0076
DM				0.000	0,100		0,170		0,170		70.00%
	Diversity Adjustment - \$/unit/da	•	0.100	0.000	0,100		0.170		0,170		
	Agricultural Employee Housing	i	100.00				100		100.00		
	Discount - %		100.00				100		100.00		

DMS-1	Culturates Disassess 64		(0.086)	0.000	(0.086)	١	(0.097)		(0.097)		-12,79%
	Submeter Discount - \$/unit/day		0,100	0.000	0.100	'	0.170		0.170		70.00%
	Diversity Adjustment - \$/unit/da	ay	0,100	0.000	0.029		0.022		0.022		-24.14%
	Basic Charge - \$/unit/day		0,029	0.000	0.027		****				
	Minimum Average Rate - \$/kW	n,	0.03776	0.00000	0.03776		0,02737		0.02737		-27.52%
	Willimidin Average Raic - SIKW		5.525								
DMS-2											
D1415-2	Submeter Discount - \$/unit/day		(0.300)	0,000	(0.300))	(0.340)		(0.340)		-13.33%
	Diversity Adjustment - \$/unit/da	av	0.100	0,000	0.100		0.170		0.170		70.00%
	Basic Charge - \$/unit/day	-9	0.029	0,000	0.029		0.022		0.022		-24.14%
	Minimum Average Rate - \$/kW	⁷ h	0.03776	0.00000	0.03776		0.02737		0.02737		-27.52%
	•										
DMS-3											
	Basic Charge Adjust - \$/unit/da	ıy	0.029	0.000	0.029		0.029	0.000	0.029		0,00%
	• .										
DS											0.0007
	Summer Season Premium - \$/	cWh/day	0.030	0.040	0.070		0.030	0.040			0.00%
	Winter Season Discount - \$/kW	/h/day	(0.030)	(0.040)	(0,070))	(0.030)	(0.040	(0.070)		0.00%
	California Alternate Rates for								100.00		
	Energy Discount	-%	100.00		100.00		100,00		100.00	-	
TOU-D-T											
	Energy Charge - \$/kWh										
	Summer Season	D! (DT.) - O D!-					0.02730	0,27401	0.30131		
	101	Baseline (BL) - On-Peak					0.02730				
		1% - 130% of BL - On-Peak 1% - 200% of BL - On-Peak					0.2099		0.45714		
		1% - 200% of BL - On-Peak 0% - 300% of BL - On-Peak					0,2099				
		Over 300% of BL - On-Peak					0,2099				
	,	O 101 200 to 01 DD - Ott-Leav					.,				
		Baseline (BL) - Off-Peak					0.0273	0.08041	0.10771		
	101	1% - 130% of BL - Off-Peak					0.0273		0,10771		
		1% - 200% of BL - Off-Peak					0,2099	0.08218	0.29211		
		0% - 300% of BL - Off-Peak					0,2099	0.08218	0.29211		
		Over 300% of BL - Off-Peak					0.2099	3 0.08218	0.29211		
	`										
	Winter Season										
		Baseline (BL) - On-Peak					0.0273				
	10	1% - 130% of BL - On-Peak					0.0273				
	13	1% - 200% of BL - On-Peak					0.2099				
	20	0% - 300% of BL - On-Peak					0.2099				
		Over 300% of BL - On-Peak					0.2099	3 0.0832	0.29314		
		Baseline (BL) - Off-Peak					0.0273				
	10	1% - 130% of BL - Off-Peak					0.0273				
	13	1% - 200% of BL - Off-Peak					0.2099				
	200	0% - 300% of BL - Off-Peak					0.2099				
	(Over 300% of BL - Off-Peak					0.2099	3 0.0675	5 0.27748	•	

	•		Dates			Se	ttlement Rates	1	
		Effect	Rates tive December	2008		Based on Est	imated Adjuste	d Revenue	
Note: Res	idential rates based on seven cent Tier 3 - Tier 5								
differentia	l and baseline allocations set at 55% of average]		ì	
aggregate	usage by CEC climate zone. End of year 2009 revenue	i i				l ì	1		Total Rate
	nt as specified in Paragraph 5.b.ii of Phase 2 Revenue	D-15	Generation	Total Rate		Delivery	Generation	Total Rate	Change
Allocation	Settlement Agreement.	Delivery	Generation	Total Nate		Delivery	Generation	Total Auto	
	Customer Charge - \$/day					0.029	0.000	0.029	
	moving. Of the					0,523	0.000	0.523	
	TOU Meter Charge — \$/day California Alternate Rates for					V.2-2			
	Energy Discount - %					100.00	0.000	100.00	
	<u></u>								
TOU-EV									
	Energy Charge - \$/kWh Summer Season - On-Peak	0.09599	0.14193	0,23792		0.11814	0.17974	0.29788	25,20%
	Off-Peak	0.09599	0.06121	0,15720		0.05798	0.05369	0.11167	-28,96%
	011 T WILL	-,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,							
	Winter Season - On-Peak	0.09599	0.08367	0.17966		0.12590	0.09622	0.22212	23.63%
	Off-Peak	0.09599	0,06398	0.15997		0.05798	0.05310	0.11108	-30.56%
	morra c. Cl	0.159	0,000	0.159		0.029		0.029	-81.76%
	TOU Meter Charge - \$/day Minimum Charge - \$/day	0.139	0.000	0.172		0.171		0.171	-0.58%
	Willimum Charge - 5/day	0.172	*						
GS-1									
	Energy Charge - \$/kWh			0.14046		0.06106	0.12604	0.19710	31.88%
	Summer	0.04157	0.10789 0.10450	0.14946 0.14607		0,06106 0,06106	0.13604 0.08604	0.14710	0.71%
	Winter	0.04157	0,10430	0.14007		0,00100	0,00001	*******	
	Customer Charge - \$/day	0,565	0,000	0.565		0.625		0.625	10,62%
	Customer Charge Gray								
	Three Phase Service - \$/day	0.138	0.000	0.138		0.031		0.031	-77.54%
	mary 6 1 37 1 01 0/1	0.609	0.000	0,609		0.366		0,366	-39.90%
	TOU-Option Meter Charge - \$/day	0.009	0:000	0,005		0.500		0,000	
	Voltage Discount, Energy - \$/kWh								
	From 2 kV to 50 kV	(0.00026)	(0.00227)			(0.00047)	(0.00217)	(0.00264)	
	above 50 kV	(0.00856)	(0.00494)	(0.01350)		(0.01474)	(0.00484)	(0.01958)	-45.04%
	California Alternate Rates for	100.00	0.00	100.00		100.00		100.00	0.00%
	Energy Discount - %	100.00	0,00	100.00		100.00		100.00	
GS_APS (S	Schedules: GS-1 and TOU-GS-1)								
3) 0117-00	Air Conditioning Cycling Credit - \$/ton/summer season day								
	30% Cycling	(0.014)	0.000	(0.014)		(0.053)	0,000	(0.053)	
	40% Cycling	(0.042)	0,000	(0.042)		(0.069)	0.000	(0,069) (0.091)	
	50% Cycling	(0.070) (0.200)	0.000	(0.070) (0.200)		(0.091) (0.370)	0,000	(0.091)	
	100% Cycling	(0.200)	0.000	(0.200)		(0.010)		(/	
GS-APS (S	Schedules: GS-2, TOU-GS-3, or TOU-8)								
	Air Conditioning Cycling Credit - \$/ton/summer season month								205 5111
	30% Cycling	(0.42)		(0.42)		(1.62)	0.00	(1.62) (2.11)	
	40% Cycling	(1.25)	0.00	(1.25)		(2.11) (2.77)	0.00	(2.11)	,
	50% Cycling 100% Cycling	(2.10) (6.00)	0,00 0,00	(2.10) (6.00)		(11.25)	0.00	(11.25)	,
	10076 Cycling	(0.00)	0,00	(**/	,	, ,		,	
GS-APS-E	(Schedules: GS-1 and TOU-GS-1)								
	Air Conditioning Cycling Credit - \$/ton/summer season day							(0.00)	100 570/
	30% Cycling	(0.028)		(0.028)		(0.064) (0.084)	0.000	(0.064 (0.084	
	40% Cycling	(0.084) (0.140)		(0.084) (0.140)		(0.084)	0.000	(0.106	,
	50% Cycling 100% Cycling	(0.140)				(0.100)		(0.416	<i>'</i>
	10070 Cyoling	(5.150)		V		, ,			
TOU-EV-	3								
	Energy Charge - \$/kWh		0.100-	0053 **		0.06106	0,24229	0.30335	20,65%
	Summer Season On-Peak	0.05429 0.05429	0.19715 0.07532			0.06106 0.06106		0.30333	
	Off-Peak	0,03429	0,01332	0.12901		0,00100	0505-1	0,11,10	
	Winter Season On-Peak	0.05429	0.10409	0.15838		0.06106		0.17430	
	Off-Peak	0.05429	0.07481	0.12910		0.06106	0.05187	0.11293	-12.52%
			0.000	0.575		0.625		0.625	10.62%
	Customer Charge - \$/day	0.565	0,000	0.565		0,023		0.023	. 10.0270
	TOU-Meter Charge-\$/day-	0,252	0.000	0.252	ŀ	0.366		0.366	45,24%
	100 1.1001 0.m.Br 4.00)								

		Rates				ettlement Rates			
	Effec	tive December	2008		Based on Es	timated Adjust	ed Revenue	г	
Note: Residential rates based on seven cent Tier 3 - Tier 5							ļ	1	1
differential and baseline allocations set at 55% of average									
aggregate usage by CEC climate zone. End of year 2009 revenue requirement as specified in Paragraph 5.b.ii of Phase 2 Revenue				ĺ					Total Rate
Allocation Settlement Agreement.	Delivery	Generation	Total Rate]	Delivery	Generation	Total Rate	L	Change
TOU-GS-1									
Energy Charge - \$/kWh Summer Season									
On-Peak	0.05429	0.14968	0.20397		0.06106	0.33856	0.39962		95.92%
Mid-peak	0.05429	0.11926	0.17355		0.06106 0.06106	0.14384 0.05900	0.20490 0.12006		18.07% -10.18%
Off-Peak Winter Season	0.05429	0.07938	0,13367		0.00100	0,03700	0,12000		,
Mid-peak	0,05429	0.12232	0.17661		0,06106	0.08316	0.14422		-18.34%
Off-Peak	0.05429	0.08352	0.13781		0.06106	0.05581	0.11687		-15.19%
Customer Charge - \$/day	0.565	0.000	0.565		0.625	0.000	0.625		10.62%
TOU-Meter-Charge \$/day	0.252	0.000	0.252		0.366	0.000	0.366		45.24%
Three-Phase Service - \$/day	0,138	0.000	0,138		0.031	0.000	0.031		-77.54%
V-land Discount France, \$ 0.000h									
Voltage Discount, Energy - \$/kWh From 2 kV to 50 kV	(0.00026)	(0.00227)	(0.00253))	(0.00047)	(0.00217)	(0.00264)		-4.50%
above 50 kV	(0.00856)	(0.00494)	(0.01350))	(0.01474)	(0.00484)	(0.01958)		-45.04%
California Alternate Rates for	100.00		100.00		100.00		100.00		0.00%
Energy Discount - %	100.00		100.00						
PPP Energy Charge - S/kWh PEAK Plus Event Time Period (2pm-6pm) PEAK Plus Event Credit - On-Peak California Alternate Rates for Energy Discount - %	100.00								
<200 kW CPP rider									
2 - 6pm CPP event Energy Charge - S/kWh					0.00000	1.05828	1.05828		
NON-Event S/kWh Credit Residential					0.00000	(0.02857)	(0.02857)		
CS 1					0.00000	(0.01034)	(0.01034)		
CS 2					0.00000	(0.00964)	(0.00964)		
Peak Time Rebate (PTR) - \$/kWh					0.0000	(0.75000)	(0.75000)		
Peak Time Rebate (PTR) with PCT - \$/kWh					0.0000	(1.25000)	(1.25000)		
Teak Time Repair (1114) Will CT Comma									
Optional CPP rider < 200 kW CPP Event Energy Charge - \$/kWh.									
DOMESTIC					0.0000				
DOMESTIC CARE					0.0000				
GS-I					0,0000	1.30229	1.50227		
Summer Non-Event Energy Credit - \$/kWh					0,000	0.04032) (0.04032)	,	
DOMESTIC DOMESTIC CARE					0.0000	•			
GS-1					0.0000	0.04044	(0.04044)	

Note: Residential rates based on five cent Tier 3 - Tier		Effec	Rates tive Decembe	r 2008			ettlement Rate timated Adjus		
Solidamia and baseline allocations set at 50% of average aggregate usage by CEC climate zone. End of year 2009 revenue requirement as specified in Paragraph 5.b.ii of Phase 2 Revenue Allocation Settlement Agreement.	Delivery	URG	DWR	Generation	Total Rate	Delivery	Generation	Total Rate	Total Rate Change
D									
Energy Charge- \$/kWh									
Baseline - Summer	0.07217	0.03412	0.08614	0.04861	0.12078	0.02411	0.09566	0.11977	-0.84%
- Winter	0.07217	0.03412	0.08614	0.04861	0.12078	0.02411	0.09566	0.11977	-0.84%
101% - 130% of Baseline - Summer	0.07217	0.06091	0.08614	0.06794	0.14011	0.04344	0.09566	0.13910	-0.72%
- Winter	0.07217	0.06091	0.08614	0.06794	0.14011	0.04344	0.09566	0.13910	-0.72%
131% - 200% of Baseline - Summer		0.15468	0.08614	0,13559	0.20776	0.17859	0.09566	0.27425	32.00%
- Winter		0.15468	0.08614	0.13559	0.20776	0.17859	0.09566	0.27425	32.00%
200% - 300% of Baseline - Summer		0.20319	0.08614	0.17059	0.24276	0.20359	0.09566	0,29925 0,29925	23.27% 23.27%
- Winter		0.20319	0.08614	0.17059	0,24276	0.20359 0.22859	0,09566 0,09566	0.29925	23.27% 16.74%
Over 300% of Baseline		0.25170	0.08614 0.08614	0,20559 0,20559	0.27776 0.27776	0.22859	0.09566	0.32425	16.74%
- Winter	0.07217	0.25170	0,08014	0,20339	0.21110	0,22639	0,05500	0.32423	10.7470
Basic Charge - \$/day									
Single-Family Residence	0.029			0.000	0.029	0.029		0.029	0.00%
Multi-Family Residence	0.022			0.000	0,022	0.022		0.022	0.00%
Minimum Charge - \$/day									0.000/
Single Family Residence				0.000	0.059	0.059		0.059	0.00%
Multi-Family Residence	0.044			0.000	0.044	0.044		0.044	0.00%
D-CARE									
Energy Charge - \$/kWh									
Baseline - Summer	0.03672	0.03412	0.08614	0.04861	0.08533	(0.01032)	0.09566	0.08534	0.01%
- Winter	0.03672	0.03412	0.08614	0.04861	0.08533	(0.01032)	0.09566	0.08534	0.01%
101% - 130% of Baseline - Summer		0.06091	0.08614	0.06794	0.10668	0.01103	0.09566	0.10669	0.01%
- Winter		0.06091	0.08614	0.06794	0,10668	0.01103	0.09566	0.10669	0.01%
131% - 200% of Baseline - Summer		0.15468	0.08614	0.13559	0.15860	0.10436	0,09566	0,20002	26.11%
- Winter		0.15468	0.08614	0.13559	0.15860	0.10436	0.09566	0.20002	26.11% 26.11%
200% - 300% of Baseline - Summer			0.08614	0,17059	0.15860	0.10436	0.09566 0.09566	0.20002 0.20002	26.11%
- Winter	, ,		0.08614	0.17059	0.15860 0.15860	0,10436 0,10436	0.09566	0.20002	26.11%
Over 300% of Baseline			0.08614 0.08614	0.20559 0.20559	0.15860	0,10436	0.09566	0,20002	26,11%
- Winter	(0.04699)	0.25170	0,08014	0,20339	0.13800	0,10430	0.09300	0,20002	20,1170
Basic Charge - \$/day									
Single-Family Residence	0.023			0,000	0.023	0.023		0.023	0.00%
Multi-Family Residence	0.017			0,000	0.017	0.017		0.017	0,00%
Minimum Charge - \$/day									0.0001
Single Family Residence				0.000	0.047	0.047		0.047	0.00%
Multi-Family Residence	0.034			0.000	0.034	0.034		0.034	0.00%



Monthly Reports Required By Paragraph 4.c

SCE shall provide the following reports on a monthly basis to the Director of the Energy Division for the period January 2009 through December 2011:

Data Points	Data Description / Comments
Total Number of Residential Accounts	Total number of customers on the residential rate as of reporting month
Total Number of Residential Accounts in Arrears	Total number of residential customer accounts not paid by day 19, bill is past due on day 20
Total Dollar Amount of Accounts in Arrears (Residential)	Residential customer accounts overdue if not paid by day 20 (Day 1), the data provided represents day 20 through day 180
Total Number of Residential Accounts Sent Notice of Disconnection	Number of residential customer accounts sent a final call notice if bill is not paid by day 51
Total Number of Residential Disconnections for Non-Payment	Number of residential customer accounts disconnected for non payment of energy account on or about day 53
Total Number of Residential Accounts Having Service Restored After Discontinuance for Non- Payment	Number of residential customer accounts restored after service was discontinued due to non-payment of energy account
Total Number of California Alternate Rates for Energy (CARE) Accounts	Total number of residential customers on CARE rate as of reporting month
Total Number of CARE Accounts in Arrears	Total number of residential CARE customer accounts not paid by day 19, bill is past due on day 20
Total Dollar Amount of CARE Accounts in Arrears	Residential CARE customer accounts overdue if not paid by day 20 (Day 1), the data provided represents day 20 through day 180
Total Number of CARE Accounts Sent Notice of Disconnection	Number of residential CARE customer accounts sent a final call notice if bill is not paid by day 51
Total Number of CARE Disconnections for Non- Payment	Number of residential CARE customer accounts disconnected for non payment of energy account on or about day 53
Total Number of CARE Accounts Having Service Restored After Discontinuance for Non-Payment	Number of residential CARE customer accounts restored after service was discontinued due to non-payment of energy account
Total Number of Family Electric Rate Assistance Program (FERA) Accounts	Total number of residential customers on FERA as of reporting month
Total Number of FERA Accounts in Arrears	Total number of residential FERA customer accounts not paid by day 19, bill is past due on day 20
Total Dollar Amount of FERA Accounts in Arrears	Residential FERA customer accounts overdue if not paid by day 20 (Day 1), the data provided represents day 20 through day 180
Total Number of FERA Accounts Sent Notice of Disconnection	Number of residential FERA customer accounts sent a final call notice if bill is not paid by day 51
Total Number of FERA Disconnections for Non- Payment	Number of residential FERA customer accounts disconnected for non payment of energy account on or about day 53
Total Number of FERA Accounts Having Service Restored After Discontinuance for Non-Payment	Number of residential FERA customer accounts restored after service was discontinued due to non-payment of energy account

Annual Reports Required By Paragraph 4.c.

SCE shall provide the following reports on an annual basis to the Director of the Energy Division for the period January 2009 through December 2011 on February 1 of each year, covering write-offs for the previous calendar year (or as soon thereafter as the data becomes available):

- 1. Dollar Value of Residential Accounts Written Off as Uncollectible, Following Shutoff for Nonpayment
- 2. Dollar Value of CARE Accounts Written Off as Uncollectible, Following Shutoff for Nonpayment.

Appendix C Baseline Allocations

Table C-1
Baseline Allocations Effective February 1, 2001 (AB1X Limits)

A	Allocations Based On Average Consumption 1989 - 1992										
Summer kWh Per Day				Winter kWh Per Day							
Baseline				Baseline							
Region	Basic	All Electric		Region	Basic	All Electric					
10	9.1	10.0		10	9.2	16.2					
13	15.8	29.0		13	11.0	32.8					
14	14.2	20.3		14	10.6	29.5					
15	42.7	42.7		15	8.8	27.4					
16	9.2	14.3		16	10.1	28.5					
17	13.1	16.9		17	10.5	24.1					

Note: Baseline allocation for Basic customers set at 55%. Baseline allocation for All-Electric customers set at 60% for summer and 70% for winter

Table C-2
Current Baseline Allocations

Allocations Based on Average Consumption 1999 - 2001								
Summ	er kWh F	er Day		Winter kWh Per Day				
Baseline				Baseline				
Region	Basic	All Electric		Region	Basic	All Electric		
10	10.2	10.0		10	10.1	16.2		
13	19.4	29.0		13	12.4	32.8		
14	17.0	20.6		14	11.5	29.5		
15	47.6	42.7		15	9.8	27.4		
16	10.0	14.3		16	10.7	28.5		
17	15.4	16.9		17	11.7	24.1		

Note: Following Baseline OIR, baseline allocation for Basic customers set at 60% with updated average consumption. All Electric customers' baseline allocation set at 70% for summer and winter.

C-1 #1600972.v1

Table C-3
Proposed Baseline Allocations (No AB1X Modifications)

1 Toposca Baseline Allocations (No AB IX modifications)								
Allocations Based on Average Consumption 2002 - 2005								
Summer kWh Per Day						Winter kW	h Per Da	У
Climate	Baseline				Climate	Baseline		
Zone	Region	Basic	All Electric		Zone	Region	Basic	All Electric
5	10A	9.1	10.0		5	10A	9.2	16.2
6	10B	9.1	10.0		6	10B	9.2	16.2
8	10C	9.1	10.0		8	10C	9.2	16.2
13	13	16.4	29.0		13	13	11.0	32.8
14	14	14.3	20.3		14	14	10.6	29.5
15	15	42.7	42.7		15	15	8.8	27.4
16	16	10.1	14.3		16	16	10.1	28.5
9	17A	13.1	16.9		9	17A	10.5	24.1
10	17B	14.4	17.4		10	17B	10.5	24.1

Note: Baseline allocation for Basic customers set at 50%. Baseline allocation for All Electric customers set at 60% for summer and 70% for winter. AB1X baseline allocations set minimum baseline allocations. See Paragraph 4.b.v of Settlement Agreement.

Table C-4
Proposed Baseline Allocations (With AB1X Modifications)

Allocations Based on Average Consumption 2002 - 2005								
Summer kWh Per Day					Winter kWh Per Day			ıy
Climate	Baseline				Climate	Baseline		
Zone	Region	Basic	All Electric		Zone	Region	Basic	All Electric
5	10A	9.1	10.0		5	10A	9.8	16.7
6	10B	9.2	10.0		6	10B	9.6	16.2
8	10C	10.2	10.0		8	10C	9.2	16.2
13	13	18.6	29.0		13	13	11.0	32.8
14	14	16.1	20.3		14	14	10.6	29.5
15	15	43.9	42.7		15	15	9.0	27.4
16	16	11.5	14.3		16	16	10.9	28.5
9	17A	13.9	16.9		9	17A	10.5	24.1
10	17B	16.0	17.4		10	17B	10.5	24.1

Note: Baseline allocation for Basic Customers set at 55%. Baseline allocation for All-Electric customers set at 60% for summer and 70% for winter. AB1X baseline allocations set minimum baseline allocations. See Paragraph 4.b.v of Settlement Agreement

ATTACHMENT D

Medium and Large Power Rate Group Rate Design Settlement Agreement

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Southern California Edison)	
Company (U 338-E) To Establish Marginal)	Application 08-03-002
Costs, Allocate Revenues, And Design Rates)	(Filed March 4, 2008)
)	
In the Matter of the Application of Southern)	
California Edison Company (U 338-E) for)	Application 07-12-020
Authority to Make Various Electric Rate Design)	(Filed December 21, 2007)
Changes.)	

PHASE 2 MEDIUM AND LARGE POWER RATE GROUP RATE DESIGN
SETTLEMENT AGREEMENT

Dated: January 29, 2009

PHASE 2 MEDIUM AND LARGE POWER RATE GROUP RATE DESIGN SETTLEMENT AGREEMENT

Parag	graph	Page
1.	Parties	1
2.	Recitals	3
3.	Definitions	3
4.	Agreement	7
5.	Implementation of Agreement	26
6.	Incorporation of Complete Agreement	26
7.	Signature Date	26
8.	Regulatory Approval	27
9.	Compromise Of Disputed Claims	27
10.	Non Precedent	27
11.	Previous Communications	27
12.	Non Waiver	27
13.	Effect Of Subject Headings	28
14.	Governing Law	28
15.	Number Of Originals	28

Appendix A - Illustrative Rates for Medium and Large Power Rate Schedules

PHASE 2 MEDIUM AND LARGE POWER RATE GROUP RATE DESIGN SETTLEMENT AGREEMENT

This Phase 2 Medium And Large Power Rate Group Rate Design 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), Federal Executive Agencies (FEA); California Manufacturers and Technology Association (CMTA); California Large Energy Consumers Association (CLECA); Energy Users Forum (EUF); the Solar Alliance; the Building Owners and Managers Associations of Greater Los Angeles, Orange County, San Francisco, and California (BOMA); Debenham Energy (Debenham), the Solar Alliance, and the Energy Producers and Users Coalition (EPUC); (referred to hereinafter collectively as Parties or Settling Parties or individually as Party).

- 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.
- b. 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.
- c. 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 service or DA customers.

- d. 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.
- e. Energy Users Forum is an ad hoc group that represents the interests of medium and large bundled service and direct access (DA) customers in California, with locations in either investor-owned utility and/or municipal utility service areas, taking service on rate schedules for accounts with demand above 100 kW. EUF represents entities that have accounts taking service on all SCE rate schedules from GS-2 to TOU-8 Subtransmission.
- f. 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.
- g. Solar Alliance is a non-profit organization with members throughout California and the country who want a rapid transition to a clean and renewable energy future.
- h. Debenham is a privately owned limited liability company that provides renewable energy consulting services, developments for its own account, and assistance for other private and public entities with development, ownership, and financing of distributed generation projects in California, primarily utilizing utility scale wind energy technologies.
- 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, Shell Oil Products US, THUMS Long Beach Company, and Occidental Elk Hills, Inc.

2. Recitals

- a. In Phase 2 of SCE's 2009 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 March 4, 2008, SCE served its initial prepared testimony regarding marginal costs, revenue allocation and rate design in Application 08-03-002.
 SCE updated its initial showing on June 27, 2008.
- c. In accordance with the Scoping Memo and Ruling of Assigned Commissioner, dated May 14, 2008, 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 12, 2008.
- d. DRA served its initial testimony on September 26, 2008. Interveners, including the Settling Parties served their initial testimony on October 31, 2008.
- e. Continuing settlement discussions occurred among the interested parties after November 12, 2008.
- f. The Parties have evaluated the impacts of the various proposals in this consolidated proceeding for A.08-03-002 and A.07-12-020 and desire to resolve all issues related to rate design for the Medium and Large Power rate groups as indicated in Paragraph 4 of this Agreement.

3. <u>Definitions</u>

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. "Backup Service" is the electric service provided by SCE to a customer who has an on-site generating facility during unscheduled outages of the on-site generator.
- c. "BIP" or Base Interruptible Program means the rate schedule applicable to customers with demands in excess of 200 kW who receive a credit applied to their summer and winter Time-Related Demand Charges in return for the customer's agreement to reduce its demand to a specified level within either 15 or 30 minutes of notification by SCE of the need to reduce load.
- d. "Capacity Reservation Charge" means the charge assessed to Schedule S customers based on the customer's designated kW level of Standby Demand.
- e. "Cold Ironing" means the provision of electrical power for lights, heating, machinery or other needs of an ocean-going vessel at the Port of Long Beach or Port of Hueneme as replacement for the vessel's auxiliary internal combustion engines or to a truck at truck stops where the truck's internal combustion engine is turned off. For purposes of eligibility, the electric usage for Cold Ironing must be separately metered and 90 percent of the metered load must displace power generation associated with vessels or trucks that would otherwise be provided by internal combustion generation on the vessel or the truck.
- f. "Critical Peak Pricing" means a dynamic rate that allows a short-term price increase of a predetermined level to reflect real-time system conditions. Typically, the time and duration of the price increase are predetermined, but the event days are not predetermined.
- g. "Settling Parties" means SCE, EUF, CMTA, CLECA, FEA, BOMA, Solar Alliance, Debenham, and EPUC.
- h. "Supplemental Service" is the service provided by SCE to a customer who has an on-site generating facility for the portion of the customer's load that

- is regularly provided by SCE as if the customer was a full-service customer.
- i. "Energy Charges" mean the dollar per kilowatt-hour (kWh) charges applicable to rate schedules in the Large Power and Medium Power Rate Groups. Energy Charges recover a portion of SCE's costs for delivery service and generation. TOU utility retained generation (URG) Energy Charges will be set residually such that the weighted average of URG and DWR Energy Charges provide a price signal consistent with marginal cost differentials in TOU energy rates.
- j. "Customer Charges" mean the dollar per month charges applicable to certain Medium and Large Power Rate Group rate schedules.
- k. "Demand Charges" mean those charges that are comprised of Facilities-Related Demand Charges and Time-Related Demand Charges, which are based on the customer's maximum kW demand during the specified billing periods. Demand Charges recover a portion of SCE's delivery and generation costs.
- 1. "EPMC" means equal percent of marginal cost. Because marginal cost revenues do not equal the utility's revenue requirement, in general, the utility revenue requirement is allocated to different rate groups in proportion to each rate group's percentage share of marginal cost revenue responsibility by function (*i.e.* separately for generation versus distribution, and customer).
- m. "Gross Nameplate Capacity" means the total gross generating capacity of a generator or a generating facility (as defined in SCE's Rule 21) as designated by the manufacturer (s) of the generators.
- n. "Facilities-Related Demand Charges" are charges applied to customers' monthly peak demands not differentiated by TOU or by season that are designed to recover certain transmission and distribution costs that are

- defined to be unrelated to generation system peak or coincident peak usage.
- o. "Time-Related Demand Charges" are generation-related, marginal cost based, capacity-related charges assigned to TOU periods based on loss-of-load probabilities or loss of load expectations during the TOU periods.

 Scaled TOU marginal energy costs along with the Time-Related Demand Charges are designed to collect the allocated revenue requirement for SCE's base generation and fuel and purchased power costs.
- p. "Large Power Rate Groups" means the following SCE rate groups in which demands are 500 kW or greater and are differentiated by service voltage as follows: TOU-8-Subtransmission (TOU-8-Sub), which is for service above 50 kV; TOU-8-Primary (TOU-8-Pri), which is for service from 2 kV to 50 kV; and TOU-8-Secondary (TOU-8-Sec), which is for service below 2 kV.
- q. "Medium Power Rate Groups" means the following rate groups: GS-2 and TOU-GS-3. Demands for the GS-2 rate group are from 20 kW to 199 kW. Demands for the TOU-GS-3 rate group are from 200 kW to 499 kW.
- r. "Permanent Load Shift" means technologies that are installed to allow customers to shift load that would otherwise occur during peak periods to off-peak periods on a permanent basis.
- s. "Functional SAPC Allocation" means allocation of SCE's revenue requirement to each of SCE's rate groups based on the system average percentage change for the particular function, *e.g.*, distribution or generation.
- t. "Renewable Distributed Generation Technologies" means solar, wind, fuel cells, and any other renewable generation technology as defined in the Statewide California Solar initiative, the Self-Generation Incentive Program, or their successors.

- u. "SCE RECC" means the method used by SCE to determine marginal customer costs for each rate group in Exhibit SCE-02 (Updated), dated June 27, 2008.
- v. "Standby Demand" is the kW level of service designated by a Schedule S customer that SCE will provide during outage periods for a Schedule S customer's generating facility.
- w. "Commission" or "CPUC" means the California Public Utilities Commission.

4. Agreement

In consideration of the mutual obligations, covenants and conditions contained herein, the Settling Parties agree to the terms of this Agreement. Nothing in this Paragraph 4 of this Agreement shall be deemed to constitute an admission or an acceptance by any Party of any fact, principle, or position contained herein. This Agreement is subject to the express limitation on precedent described in Paragraph 10. The Parties, by signing this Agreement, acknowledge that they pledge support for Commission approval and subsequent implementation of all the provisions of the Agreement.

a. Common Pricing Principles

1. Customer Charges

Except as otherwise specified in this Agreement, Customer Charges (SCE RECC basis) shall be set at the full EPMC level for customers with demands of 20 kilowatts (kW) or more who are served on TOU rate schedules effective October 1, 2009. Customer Charges (SCE RECC basis) for non-TOU rate schedules, *e.g.* Schedule GS-2, 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 full EPMC level effective October 1, 2009.

2. Rate Structure

The current rate structure, consisting of Customer Charges, Energy Charges, and Demand Charges shall be maintained for all applicable rate schedules with the exception of Schedule GS-2-TOU (Option B), where on-peak and mid-peak Time-Related Demand Charges shall now apply.

3. Implementing Revenue Changes in Rates

Changes to Customer Charges, Energy Charges, and Demand Charges shall be implemented on a Functional SAPC allocation basis whenever changes to SCE's authorized distribution and generation revenue requirements are implemented.

4. Non-Generation Related Energy Charges

Energy Charges that are designed to recover revenues associated with transmission, distribution, public purpose programs, nuclear decommissioning, CARE balancing account, the California Department of Water Resources bonds, and the California Public Utilities Commission reimbursement fee shall be established on the basis of the specific functional authorized revenue requirements and the terms specified in the 2009 GRC Phase 2 Revenue Allocation Agreement, which was filed January 9, 2009.

5. Demand Charges

Demand Charges shall be differentiated by season. However, the seasonality, and in some cases time differentiation, shall be retained in design of the Time-Related Demand Charges only, with no seasonal or TOU differences in the Facilities-Related Demand Charges.

6. Voltage Discounts

Customers served at higher voltage delivery levels than the design voltage level for their rate group will receive a voltage discount reflecting the lower cost of service. SCE will establish the discount levels based on the difference in marginal costs of service between the design or predominant voltage level for a given rate group and the higher voltage service options. Voltage discounts shall apply to rate schedules in the Medium and Large Power Rate Groups.

7. CPP Program Design and Revenue Treatment

a. CPP Design

SCE's CPP tariff shall allow no more than 15 events per year, nor less than 9 events per year, but is designed to be activated for 12 events per year on non-holiday summer weekdays and may occur only during the time period from 2:00 p.m. to 6:00 p.m. The CPP rate design structure, consisting of CPP energy adders and demand charge credits, shall be implemented as described by SCE's testimony in Exhibit SCE-04 (updated).

b. CPP Bill Protection

A customer who is subject to the CPP tariff (regardless of demand level) shall be provided bill protection such that bills under CPP for the first 12 months shall not exceed bills calculated on the customer's otherwise applicable tariff (OAT) provided the customer remains on the CPP tariff for a full year. Customers who do not remain on the CPP tariff for a full year shall forfeit any bill protection credits. SCE shall track the bill protection revenue deficiency by rate group and assign subsequent collection of the revenue deficiency to bundled service customers within the corresponding rate groups in a subsequent rate

change proceeding, such as SCE's annual ERRA proceeding.

c. CPP Revenue Allocation Impacts

An undercollection of revenues relative to the design of the CPP rate may occur when fewer than twelve events per year are called, and an overcollection may occur when the number of called events is greater than twelve events per year. In order to minimize and account for revenue imbalances resulting from this variation, the Settling Parties agree that the minimum number of called events shall be nine events and that the undercollection or overcollection resulting from the difference between actual called events and twelve events as designed shall be assigned to the summer on-peak and mid-peak periods as a flat cent per kWh surcharge in the subsequent annual period for the CPP participants within each rate group that is responsible for the amount of the revenue imbalance.

8. Demand Response Credits

Rate structures and rate designs associated with SCE's demand response programs, *e.g.*, BIP, APS, and CPP shall be as proposed by SCE testimony in Exhibit SCE-04 (Updated), dated June 27, 2008. Customers enrolled in BIP and APS shall not be eligible for service on CPP rates.

9. Illustrative Rates

Rates for the Medium and Large Power Rate Groups shall be designed consistent with the illustrative rates in Appendix A.

b. Large Power Rate Groups

1. New Schedules

a. Default CPP

Schedule TOU-8 with the associated CPP components shall be the default rate schedule for commercial and industrial customers with demands greater than 500 kW. Schedules TOU-8-CPP-GCCD and TOU-8-VCD shall be eliminated. Customers may opt out from the CPP tariff upon notice as required under SCE's tariffs.

b. Schedule TOU-8, Option A

Schedule TOU-8, Option A, shall be offered as an alternate rate for customers with demands greater than 500 kW who employ Cold Ironing or Permanent Load Shift technologies.

- i. To be eligible for the Cold Ironing option, the customer must comply with any applicable requirements of Rule 18.
- ii. Rates for Schedule TOU-8, Option A, shall be structured to recover all generation-related capacity costs through volumetric energy charges on a cent per kWh basis. No changes will be made to the structure for recovering delivery-related demand charges.

c. Schedule TOU-8, Option B

Schedule TOU-8 Option B shall be the OAT for customers in the Large Power Rate Groups (who opt out of the default TOU-8 rate schedule with CPP components or who are ineligible for CPP rates) and shall include Customer

Charges, Energy Charges, and Demand Charges, designed as specified in this Agreement for the Large Power Rate Groups.

d. Experimental Schedule For Renewable Generating Technologies

An experimental rate shall be offered as an optional rate schedule for customers with demands greater than 20 kW but not exceeding four megawatts (MW) and who employ Renewable Distributed Generation Technologies. SCE will offer Schedule TOU-8-R to customers in the Large Power Rate Groups and similar rate structures to customers in the GS-2 and TOU-GS-3 rate groups under Schedules GS-2-TOU-R, and TOU-GS-3-R respectively. Participation on these rate schedules will be limited to a cumulative installed distributed generation output capacity of 150 MW for all eligible rate groups.

- Eligible customers must install, own, or operate an eligible onsite Renewable Distributed Generation Technologies system with a net capacity that is 15 percent or greater than the customer's annual peak demand.
- ii. Rates for Schedules TOU-8-R, TOU-GS-3-R, and GS-2-TOU-R shall be structured to recover all generation-related capacity costs through volumetric energy charges on a cent per kWh basis in a manner that maintains the same TOU allocation of generation revenue recovery.
- iii. The distribution component of the Facilities-Related

 Demand Charge shall be set at 50 percent of the

total Facilities-Related Demand Charge for the customer's otherwise-applicable tariff less the transmission-related demand charge. If the transmission-related demand charge is more than 50 percent of the total Facilities-Related Demand Charge, then the distribution component of the Facilities-Related Demand Charge will be set at 50 percent of the comparable distribution component in the customer's otherwise applicable tariff. The revenue deficiency resulting from this adjustment shall be collected by a non-time differentiated, cent per kWh volumetric charge. FERC jurisdictional transmission-related demand charges shall not be affected by this Agreement.

- iv. SCE will offer experimental Schedules TOU-8-R, TOU-GS-3-R, and GS-2-TOU-R through the three-year term of SCE's 2009 GRC until rates are implemented in Phase 2 of SCE's 2012 GRC when the distribution Facilities-Related Demand Charges will be redesigned to reflect these customer's actual contribution to the distribution system costs.
 Customers who were served on these rate schedules prior to implementation of new rates in SCE's 2012 GRC shall be grandfathered, but the schedules shall be subject to redesign.
- v. Prior to SCE's 2012 GRC, SCE will conduct a study to determine solar customers' contribution to the distribution and generation system peaks and the effect of such contribution on revenue allocation.

2. Other Schedules and Options

- a. Schedule TOU-8-BU shall be retained with charges modified consistent with other schedules in the Large Power Rate Groups.
- b. As specified in Appendix E to Exhibit SCE-04 (Updated), dated June 27, 2008, the method for determining power factor adjustment rates will be revised to more closely reflect SCE's cost of correcting poor power factor conditions. The power factor adjustment rates shall be \$0.32 \$/kVAR for service voltages greater than 50 kV and \$0.27 \$/kVAR for service voltages less than 50 kV.
- c. The real-time energy prices for Schedule RTP-2 shall be modified as described in Exhibit SCE-04 (Updated), dated June 27, 2008 consistent with the following: Schedule RTP-2 generation capacity charges shall reflect a generation marginal capacity cost of \$114.10 per kW per year for the Large Power Rate Groups. Schedule RTP-2 Energy Charges shall reflect a generation marginal energy cost based on a natural gas burnertip price of \$7.00 per million BTUs. Delivery service rates for Schedule RTP-2 shall be the delivery service rates from the customer's voltage-differentiated otherwise applicable tariff.
- d. The Optimal Billing Period shall be retained, allowing customers to align their billing and production cycles twice within a six-month period.

3. Customer Charges

Effective October 1, 2009, estimated monthly Customer Charges shall be as follows:

Large Power Rate Groups
Estimated Monthly Customer Charges

Rate Group	Customer Charge
TOU-8-Sec	\$542.25
TOU-8-Pri	\$291.00
TOU-8-Sub	\$2,232.25

4. Time-Related Demand Charges

Consistent with the values for marginal generation capacity cost, marginal energy cost, and the estimated adjusted consolidated revenue requirement set forth in the Phase 2 Revenue Allocation Settlement Agreement, effective October 1, 2009, the estimated Time-Related Demand Charges set to recover the allocated generation revenues for TOU-8-Sec, TOU-8-Pri and TOU-8-Sub shall be as set forth in the table, below, subject to the applicable discount for transmission voltage level service. The Time-Related Demand Charges for the TOU-8-Pri and TOU-8-Sub rate groups shall be established consistent with the values for marginal generation capacity cost, marginal energy cost, relative loss-ofload expectation and the estimated adjusted consolidated revenue requirement set forth in the Phase 2 Revenue Allocation Settlement Agreement, effective October 1, 2009. The Time-Related Demand Charges for the TOU-8-Sec rate group shall be established in the same manner as for the TOU-8-Pri and TOU-8-Sub rate groups, with the exception of an assumed marginal generation capacity cost of \$95 per kW per year, instead of \$114.10 per kW per year that underlies the Phase 2 Revenue Allocation Settlement Agreement. To maintain consistent TOU generation cost recovery, the deficiency from the SCE generation revenue allocated to the TOU-8-Sec rate group caused by this adjustment to the marginal generation capacity cost shall be recovered solely in the summer season on-peak and mid-peak Energy Charges for the TOU-8-Sec

rate group in a manner that maintains the same TOU allocation of generation revenue recovery.

Large Power Rate Groups
Estimated Time-Related Demand Charges

	TOU-8-Sec	TOU-8-Pri	TOU-8-Sub
Summer On- Peak \$/kW	19.73	23.82	20.26
Summer Mid- Peak \$/kW	5.56	6.68	5.35

On October 1, 2009, these estimated Time-Related Demand Charges shall be adjusted as necessary consistent with the Phase 2 Revenue Allocation Settlement Agreement. These estimated Time-Related Demand Charges shall be adjusted, as necessary, by the appropriate SAPC generation scalar when SCE's authorized revenues change after October 1, 2009.

5. Facilities-Related Demand Charges

The estimated Facilities-Related Demand Charges (set to recover certain allocated delivery revenues, including SCE's adopted transmission revenues) for TOU-8-Sec, TOU-8-Pri, and TOU-8-Sub shall be established consistent with SCE's proposed marginal costs (Exhibit SCE-02 (Updated) and rate design testimony (Exhibit SCE-04 (Updated)) as follows, subject to the applicable discount for transmission voltage level service:

Large Power Rate Groups
Estimated Facilities-Related Demand Charges

	TOU-8-Sec	TOU-8-Pri	TOU-8-Sub
\$/kW	11.70	10.96	4.47

On October 1, 2009, these estimated Facilities-Related Demand Charges shall be adjusted as necessary consistent with the Phase 2 Revenue Allocation Settlement Agreement. These estimated Facilities-Related Demand Charges shall be adjusted, as necessary, by the appropriate SAPC distribution scalar when SCE's authorized revenues change after October 1, 2009 and consistent with then-current FERC-authorized transmission revenues.

6. Energy Charges

Total generation-related Energy Charges shall be established based on marginal energy costs by TOU periods set forth in the Phase 2 Revenue Allocation Settlement Agreement in order to recover, in conjunction with the Time-Related Demand Charges, SCE's generation revenues allocated to each Large Power Rate Group. With the exception of the TOU-8-Sec rate group (to be consistent with Paragraph 4.b.4, above) the estimated Energy Charges set forth in Appendix A are consistent with the values for marginal generation capacity cost, marginal generation energy cost, and the estimated adjusted consolidated revenue requirement set forth in the Phase 2 Revenue Allocation Settlement Agreement, effective October 1, 2009.

c. Medium Power Rate Groups

1. **GS-2 Rate Group**

Customers with peak demands of 20 kW to 199 kW shall take service on a default basis on an applicable non-TOU rate schedule (Schedule GS-2) with eligibility to participate in a CPP tariff. (Customers with peak demands of less than 20 kW may also elect to take service on an applicable rate schedule in the GS-2 rate group.) Customers shall also have the option of taking service on a TOU rate schedule, *e.g.* Schedule GS-2-TOU, Option A or Option B.

2. Schedule GS-2 and TOU Rate Structure

For Schedule GS-2, the default rate structure shall consist of a monthly Customer Charge, seasonal Time-Related Demand Charge, a Facilities-Related Demand Charge, and seasonal Energy Charges.

a. Customer and Meter Charges

Effective October 1, 2009, the estimated Customer Charge shall be \$114.25 per month. There shall be no incremental charge for TOU metering.

b. Facilities-Related Demand Charge

The estimated Facilities-Related Demand Charges (set to recover certain allocated delivery revenues, including SCE's adopted transmission revenues) for the GS-2 rate group shall be established consistent with SCE's proposed marginal costs (Exhibit SCE-02 (Updated) and rate design testimony (Exhibit SCE-04 (Updated)) as shown in Attachment A. On October 1, 2009, these estimated Facilities-Related Demand Charges shall be adjusted as necessary consistent with the Phase 2 Revenue Allocation Settlement Agreement. These estimated Facilities-Related Demand Charges shall be adjusted, as necessary, by the appropriate SAPC distribution scalar when SCE's authorized revenues change after October 1, 2009 and consistent with then-current FERC-authorized transmission revenues.

c. Time-Related Demand and Energy Charges

The Time-Related Demand Charges for the GS-2 rate group shall be established in the same manner as for the TOU-8-Sec rate group, with an assumed marginal

generation capacity cost of \$95 per kW per year, instead of \$114.10 per kW per year that underlies the Phase 2 Revenue Allocation Settlement Agreement. The deficiency from the SCE generation revenue allocated to the GS-2 rate group caused by this adjustment to the marginal generation capacity cost shall be recovered solely in the summer season Energy Charges for Schedule GS-2 (non TOU option) or in the on-peak and mid-peak Energy Charges for Schedule GS-2 (TOU Options). With the exception of these adjustments, generation-related Energy Charges shall be established based on generation marginal energy costs by TOU periods set forth in the Phase 2 Revenue Allocation Settlement Agreement in order to recover, in conjunction with the Time-Related Demand Charges, SCE's generation revenues allocated to the GS-2 rate group. The estimated Energy Charges set forth in Appendix A are consistent with the values for marginal generation capacity cost, marginal energy cost, and the estimated adjusted consolidated revenue requirement set forth in the Phase 2 Revenue Allocation Settlement Agreement, effective October 1, 2009.

3. Bill Limiter

SCE shall retain the bill limiter provision of Schedule GS-2.

4. TOU-GS-3 Rate Group

Customers with peak demands of 200 kW to 499 kW shall take service on Schedule TOU-GS-3 which includes the CPP components on a default basis. Customers may opt out to Schedule TOU-GS-3, Option B or other applicable tariffs. There shall be no incremental charge for TOU metering.

a. Customer Charge

Effective October 1, 2009, the estimated Customer Charge shall be set at \$443.75 per month.

b. Facilities-Related Demand Charge

The Facilities-Related Demand Charges shall be determined the same as for the Large Power Rate Groups, depending on the service voltage level.

c. Time-Related Demand and Energy Charges

The Time-Related Demand Charges for the TOU-GS-3 rate group shall be established in the same manner as for the TOU-8-Sec rate group, with an assumed marginal generation capacity cost of \$95 per kW per year, instead of \$114.10 per kW per year that underlies the Phase 2 Revenue Allocation Settlement Agreement. The deficiency from the SCE generation revenue allocated to the TOU-GS-3 rate group caused by this adjustment to the marginal generation capacity cost shall be recovered solely in the onpeak and mid-peak Energy Charges for Schedule TOU-GS-3 and its TOU options. With the exception of these adjustments, generation-related Energy Charges shall be established based on generation marginal energy costs by TOU periods set forth in the Phase 2 Revenue Allocation Settlement Agreement in order to recover, in conjunction with the Time-Related Demand Charges, SCE's generation revenues allocated to the TOU-GS-3 rate group. The estimated Energy Charges set forth in Appendix A are consistent with the values for marginal generation capacity cost, marginal energy cost, and the estimated adjusted consolidated revenue requirement set forth in the Phase 2

Revenue Allocation Settlement Agreement, effective October 1, 2009.

5. **SOP Option**

Schedule TOU-GS-3-SOP shall retain its existing rate and TOU period structure. SCE shall update Schedule TOU-GS-3-SOP Energy Charges and Demand Charges consistent with those charges established for Schedule TOU-GS-3, as specified in paragraph 4.c.2.a, b, and c, above.

6. **TOU-EV-4**

Schedule TOU-EV-4 off-peak Energy Charges will provide discounted off-peak charging rates, subject to a floor price defined as the sum of SCE's marginal generation and distribution costs plus nonbypassable charges as defined by D.07-11-052. On-peak Energy Charges will be set consistent with Schedule TOU-GS-3 on-peak Energy Charges but will reflect the different time-period definitions offered for the charging of commercial electric vehicles and incremental revenue recovery associated with the provided off-peak discount.

d. Standby Rate Design

Schedule S is the applicable rate schedule for customers who install onsite generation and receive electric service from SCE either as Supplemental, Backup, or Maintenance service. The Schedule S rate structure for Backup and Maintenance service shall consist of a Capacity Reservation Charge, a Customer Charge, Demand Charges, Time-Related Demand Charges, and Energy Charges.

1. Customer Charges, Power Factor and Voltage Adjustments

The Schedule S Customer Charge shall be equal to Customer Charge that applies to the OAT for the maximum demand level, *i.e.*, for maximum demands of 500 kW or less, or greater than

500 kW as differentiated by delivery voltage levels. Customer Charges for Schedule S customers taking both Backup and Supplemental service through a single delivery point shall be assessed solely on the customer's OAT.

The power factor adjustment shall be applied in accordance with the customer's OAT.

Schedule S customers served at higher voltage delivery levels than the design voltage level for their corresponding rate group shall receive a voltage discount in accordance with the customer's OAT.

2. Capacity Reservation Charge

The level of Standby Demand shall be designated by the customer and shall be less than or equal to the Gross Nameplate Capacity of the customer's generating facility. SCE shall have the right to verify that the customer's designated Standby Demand does not exceed the Gross Nameplate Capacity of the customer's generating facility. The Standby Demand shall be charged the Capacity Reservation Charge which consists of: (1) a transmission component, which is established under FERC jurisdiction; and (2) if applicable, a distribution component. The distribution components of the Capacity Reservation Charge are determined by adjusting the voltage level \$/kW-year marginal distribution costs by the applicable distribution Equal Percent of Marginal Cost (EPMC) revenue scalar. The distribution cost components are then adjusted by a voltage-differentiated, effective demand factor and illustrative results are shown, by voltage level, in the following table:

Voltage Level	Distribution \$/kW-Year	Distribution Component of the Capacity Reservation Charge (\$/kW-month)
Below 2 kV	\$40.00	\$4.00
From 2 kV to 50 kV	\$39.00	\$3.91
Above 50 kV but below 220 kV	\$6.00	\$0.58
At 220 kV	\$0.00	\$0.00

For customers taking only Backup Service, the Capacity
Reservation Charge shall be in lieu of a Facilities-Related Demand
Charge. A customer taking both Backup and Supplemental service
shall be charged the Capacity Reservation Charge for Standby
Demand and the OAT Facilities-Related Demand Charge for all
facilities-related demand in excess of the Standby Demand.
Customers who meet all the provisions of the Physical Assurance
Contract and who schedule Maintenance Service under the terms
of the Physical Assurance contract shall be exempt from the
Capacity Reservation Charge under normal operations. The
Capacity Reservation Charge and Backup Time—Related Demand
Charges will however apply during the period the customer
receives energy from SCE under the Maintenance Service
provision of the Physical Assurance contract.

3. Time-Related Demand Charges

A new Time-Related Demand Charge will apply to Backup Service. The generation demand-related charge shall be determined based on each voltage level's contribution to the top 100 hours peak demand and shall be assigned by TOU periods. Any revenue deficiency resulting from this lower, cost-based, generation demand charge for Backup Service is to be recovered through an increase in Energy Charges for customers within the OAT rate group in the corresponding TOU periods.

The Time-Related Demand Charges for the Schedule S TOU-8-Pri, TOU-8-Sub rate groups shall be designed consistent with the method specified in this Agreement for the Time-Related Demand Charges for the TOU-8-Pri and TOU-8-Sub rate groups. The Schedule S Time-Related Demand Charges for the TOU-8-Sec rate group shall be designed consistent with the method specified in this Agreement for the Time-Related Demand Charges for the TOU-8-Sec rate group.

a. TOU-8-SUB, TOU-8-PRI, and TOU-8-SEC Time-Related Demand Charges

The estimated Time-Related Demand Charges ultimately expected to result after implementation of a phased-in reduction, which is described in Paragraph 4.d.4, below, are as follows:

Standby
Estimated Time-Related Demand Charges

	Secondary	Primary	Subtransmission	Transmission
Summer On-Peak \$/kW	12.59	13.43	11.79	11.67
Summer Mid-peak \$/kW	3.27	3.40	2.18	2.16

b. Adjustments To Time-Related Demand Charges

Adjustments made to estimated Time-Related Demand Charges shall be consistent with the Phase 2 Revenue Allocation Settlement Agreement and the appropriate SAPC generation scalar when SCE's authorized revenues change after October 1, 2009.

c. As early as practicable in 2011 the ratio of the Backup
 Service Time-Related Demand Charge to the Supplemental

Service Time-Related Demand Charge shall be maintained as indicated in the following table:

TOU Period	TOU-8-SEC	TOU-8-PRI	TOU-8-SUB
On-Peak	0.64	0.56	0.58
Mid Peak	0.59	0.51	0.41

4. Phase-In of Reduced Time-Related Demand Charges For Backup Service

The Settling Parties agree that in order to reflect the diversity of demand imposed by Backup customers, the Time-Related Demand Charges for Schedule S shall be assessed separately from other customers in the corresponding rate groups. This results in lower Time-Related Demand Charges than those determined for the customers served on the OAT for the corresponding rate group. The revenue deficiency resulting from applying lower Time-Related Demand Charges for Backup Service shall be offset by increasing the summer On-Peak and Mid-Peak Energy Charges for the OAT for the corresponding rate group (e.g., the revenue deficiency resulting from lower Time-Related Demand Charges for TOU-8-Sub standby customers would be offset by increasing the Energy Charges on the OAT for TOU-8-Sub). In order to mitigate bill impacts, the Settling Parties agree that SCE should phase-in the reduction in Schedule S Time-Related Demand charges, with fifty percent of the reduction effective on or after October 1, 2009, and the remaining fifty percent reduction effective when SCE's 2011 ERRA revenue requirement changes go into effect.

5. Energy Charges

All kWh usage, whether Supplemental, Backup, or Maintenance service will be billed at the Energy Rates on the customer's OAT.

6. Supplemental Service Rates

All usage for Supplemental Service will be billed in accordance with the rates specified on the customer's OAT.

7. Illustrative Rates

Rates for the Standby Rate Groups shall be designed consistent with the illustrative rates in Appendix A.

5. Implementation of Agreement

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 but no earlier than October 1, 2009.

6. 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 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.

7. Signature Date

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

8. 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.

9. 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.

10. Non Precedent

Consistent with Rule 12.5 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 or unless the Commission expressly provides otherwise.

11. 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.

12. 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.

13. <u>Effect Of Subject Headings</u>

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

14. 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.

15. 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.

SOUTHERN CALIFORNIA EDISON COMPANY

By: /s/ BRUCE REED

Title: Senior Attorney Date: 2/5/2009

FEDERAL EXECUTIVE AGENCIES

By: /s/ NORM FURUTA

Title: Associate Counsel Date: 2/3/2009

CALIFORNIA MANUFACTURERS AND TECHNOLOGY ASSOCIATION

By: /s/ KEITH McCREA

Title: Attorney Date: 2/5/2009

ENERGY USERS FORUM

By: /s/ CAROLYN KEHREIN

Title: Consultant Date: 2/3/2009

CALIFORNIA LARGE ENERGY CONSUMERS ASSOCIATION

By: /s/ WILLIAM BOOTH

Title: Attorney Date: 2/5/2009

BOMA

By: /s/ BILL F. ROBERTS

Title: President, Economic Sciences Corp. Date: 2/5/2009

SOLAR ALLIANCE

By: /s/ TOM BEACH

Title: Consultant Date: 2/5/2009

ENERGY PRODUCERS AND USERS COALITION

By: /s/ NORA SHERIFF

Title: Counsel Date: 2/5/2009

DEBENHAM ENERGY, LLC

By: /s/ DONALD C. LIDDELL

Title: Counsel Date: 2/5/2009



	-m	Rates			Se	ettlement Rat	tes
	Effecti	ive Decembe	er 2008				
lote: End of year 2009 revenue requirement as specified a Paragraph 5.b.ii of Phase 2 Revenue Allocation							
ettlement Agreement. S-2 (Non TOU Option)	Delivery	Generation	Total Rate	D	elivery	Generation	Total Rate
Energy Charge - \$/kWh	0.01612	0.06020	0.00542		0.01060	0.07074	0.00022
Summer Winter	0.01613 0.01613	0.06929 0.06176	0.08542 0.07789		0.01969 0.01969	0.07964 0.06510	0.09933 0.08479
Summer Time Related Demand Charge - \$/kW	0.00	18.62	18.62		0.00	21.11	21.11
Voltage Discount, Time-Related Demand - \$/kW							
From 2 kV to 50 kV	0.00	(0.40)	(0.40)		0.00	(0.56)	(0.56)
above 50 kV	0.00	(1.04)	(1.04)		0.00	(1.55)	(1.55)
(TOU Option A) Energy Charge - \$/kWh							
Summer Season							
On-Peak	0.01613	0.21879	0.23492		0.01969	0.34112	0.36081
Mid-peak	0.01613	0.17469	0.19082		0.01969	0.13287	0.15256
Off-Peak	0.01613	0.04756	0.06369		0.01969	0.05486	0.07455
Winter Season	0.01612	0.07556	0.09169		0.01969	0.07751	0.00720
Mid-peak Off-Peak	0.01613 0.01613	0.07556	0.09169		0.01969	0.07/51	0.09720 0.07164
2 (TOU Option B)							
Energy Charge - \$/kWh							
Summer Season On-Peak	0.01613	0.09106	0.10719		0.01969	0.12716	0.14685
Mid-peak	0.01613	0.03100	0.08837		0.01969	0.08045	0.10014
Off-Peak	0.01613	0.04756	0.06369		0.01969	0.05486	0.07455
Winter Season							
Mid-peak Off-Peak	0.01613 0.01613	0.07556 0.05111	0.09169 0.06724		0.01969 0.01969	0.07751 0.05195	0.09720 0.07164
Time Related Demand Charge - \$/kW	0.00	18.62	18.62		0.00	0.00	0.00
Summer Season							
On-Peak					0.00	18.50	18.50
Mid-Peak					0.00	5.65	5.65
Voltage Discount, Time-Related Demand - \$/kW							
From 2 kV to 50 kV	0.00	(0.40)	(0.40)		0.00	(0.56)	(0.56)
above 50 kV	0.00	(1.04)	(1.04)		0.00	(1.55)	(1.55)
(All Options) Customer Charge - \$/month	94.65	0.00	94.65		114.25		114.25
Facilities Related Demand Charge - \$/kW	9.54	0.00	9.54		11.62		11.62
Single Phase Service - \$/month	(29.42)	0.00	(29.42)		(9.94)		(9.94)
Voltage Discount, Facilities Related Demand - \$/kW							
From 2 kV to 50 kV	(0.19)	0.00	(0.19)		(0.14)		(0.14)
above 50 kV	(6.24)		(6.24)		(4.28)		(4.28)
Voltage Discount, Energy - \$/kWh	. ,		. ,				
From 2 kV to 50 kV	0.00000	(0.00199)	(0.00199)		0.00000	(0.00140)	(0.00140)
above 50 kV	0.00000	(0.00433)	(0.00433)		0.00000	(0.00311)	(0.00311)
CARE Energy Discount - %	100.00%				100.00%		100.00%
Bill Limiter (GS-1 to GS-2) - %	20.89%	79.11%	100.00%		20.89%	79.11%	100.00%
TOU Option Meter Charge - \$/month							
Standard	18.43	0.00	18.43		21.23		21.23
TOU-RTEM	158.83	0.00	158.83		88.48		88.48

End of year 2009 revenue requirement as specified agraph 5.b.in of Phase 2 Revenue Allocation ment Agreement. 28 (Schedules: GS-2, TOU-GS-3, or TOU-8) Air Conditioning Cycling Credit - Shorhsummer season month 30% Cycling (2.10) 0.00 (2.21) (2.10) (2.1			Pates				Settlement Ra
Separation Delivery Generation Total Rate Generation		Effect	Rates tive Decemb	er 2008	•	settiement Ka	ites
Delivery Generation Delivery Generation Total Fate Generation Total Fate Generation Total Fate Generation Total Fate Generation Gene							
Delivery Ceneration Delivery Ceneration Total Rate Conditioning Cycling Cyclin Short-luminer teason month Short Cycling Carbo Ca	te: End of year 2009 revenue requirement as specified						
Stehedules: GS-2, TOU-GS-3, or TOU-5) Air Conditioning Cycling Cycling Cycling Cycling Cycling Cycling (1.25) 0.00 (1.25) 0.00 (1.25) 0.00 (1.27) 0.00 (1.27) 0.00 (1.25) 0.00 (1.25) 0.00 (1.25) 0.00 (1.27) 0.00 (1.25) 0.0							
Air Conditioning Cycling Credit - Shorn/summer season month a 40% Cycling (1.25) 0.00 (1.25) (1.52) 0.00 (1.02) (1.02) 0.00 (2.04) (1.27) 0.00 (2.06) (1.02) 0.00 (2.04) (1.02) 0.00 (2.06) (1.02) 0.00 (2.06) (1.02) 0.00 (2.06) (1.02) 0.00 (1.12) 0.00 0.00 (1.12) 0.00 (1.12) 0.00 (1.12) 0.00 (1.12) 0.00 (1.12) 0.00 0.00 (1.12) 0.00 (1.12) 0.00 0.00 (1.12) 0.00 0.00 0.00 0.00 0.00 0.00 0.00 0.	nent Agreement.	Delivery	Generation	Total Rate	Delivery	Generation	Total Ra
Air Conditioning Cycling Cradit - Shonisummer season month a 40% Cycling	S (Schodules: GS 2 TOH GS 2 or TOH 9)						
30% Cycling	•	h					
S9K Cycling			0.00	(0.42)	(1.62	0.00	(1.62
\$\$\frac{1}{2}\$\$ \frac{1}{2}\$\$	40% Cycling	(1.25)	0.00	(1.25)	(2.11	0.00	(2.11
## Schedules: GS-2, TOU-GS-3, or TOU-8) Alf Conditioning Cycling Credit - Strenisummer season month Alf Conditioning Cycling Credit - Strenisummer season month 30% Cycling (250) 0.00 (259) (255) 0.00 (255) 50% Cycling (250) 0.00 (421) (321) 0.00 (256) 50% Cycling (250) 0.00 (420) (321) 0.00 (256) 100% Cycling (1200) 0.00 (1200) (1200) (1264) 0.00 (256) Energy Charge - ShWh Below 2 kV 0.01481 Variable* Variable* 0.01738 Variable* Variable* From 2 kV to 50 kV 0.01434 Variable* Variable* 0.01734 Variable* Variable* From 2 kV to 50 kV 0.01483 Variable* Variable* 0.01734 Variable* Variable* From 2 kV to 50 kV 0.0189 Variable* Variable* 0.01734 Variable* Variable* From 2 kV to 50 kV 275.69 0.00 275.69 291.00 0.00 291.00 Facilities Related Denand Charge - ShWh Below 2 kV 247.22 2.00 0.247.22 2.232.25 0.00 2.233.26 Facilities Related Denand Charge - ShW From 2 kV to 50 kV 2.75.69 0.00 10.77 11.70 0.00 11.77 From 2 kV to 50 kV 2.75.69 0.00 10.77 11.70 0.00 11.70 Voltage Discount, Exallity-Related ShW 2.00% 0						*	(2.77
Air Conditioning Cycling Cycling Cycling (2.50) 0.00 (2.50) (2.55) 0.00 (2.55)	100% Cycling	(6.00)	0.00	(6.00)	(11.25	0.00	(11.25
Air Conditioning Cycling Credit - Situn/summer season month 30% Cycling (2.50) 0.00 (2.50) (2.55) 0.00 (2.55) 40% Cycling (2.50) 0.00 (2.50) (2.55) 0.00 (2.55) 50% Cycling (2.50) 0.00 (2.20) (2.20) (2.25) 0.00 (2.25) 100% Cycling (12.00) 0.00 (12.00) (12.64) 0.00 (12.64) Energy Charge - SikWh Bolow 2 kV 0.01434 Variable* Variable* 0.01735 Variable* Variable* Variable* Variable* 0.01734 Variable* Variable* 0.01734 Variable* Variable* 0.01735 Variable* Variable* Variable* 0.01734 Variable* Variable* 0.01735 Variable* Variable* 0.01735 Variable* Variable* 0.01736 Variable* 0.017	S.F (Schedules: GS.2 TOU-GS.3 or TOU-8)						
39% Cycling 40% Cycling (2.50) 0.00 (2.55) (2.55) (2.55)	• • • • • • • • • • • • • • • • • • • •	h					
Energy Charge - \$AWh			0.00	(0.84)	(1.93	0.00	(1.93)
Energy Charge - SAWh	40% Cycling	(2.50)		(2.50)	(2.55	0.00	(2.55)
Energy Charge - \$AWh Below 2 kV	· -						
Below 2 kV 201481 Variable* 0.01786 Variable* 0.01786 Variable* Variable* 201784 Variable*	100% Cycling	(12.00)	0.00	(12.00)	(12.64	0.00	(12.64)
Below 2 kV 0.01481 Variable* 0.01784 Variable* 0.01734 Variable* 0.01734 Variable* Variabl							
Bellow 2 kV 0.01481 Variable* 0.01784 Variable* 0.01784 Variable* 0.01784 Variable* Variab	Energy Charge - \$/kWh						
Balow 50 kV 0.01289 Variable* Vari		0.01481	Variable*	Variable*	0.0178	5 Variable*	Variable*
Customer Charge - S/month Below 2 kV 458.04 458.04 542.25 0.00 251.00 From 2 kV 50 kV 275.69 0.00 275.69 291.00 0.00 291.00 showe 50 kV 2,427.22 0.00 2,472.22 2,232.25 0.00 2,232.25 Facilities Related Demand Charge - S/kW 10.77 0.00 10.77 11.70 0.00 11.70 Below 2 kV 10.21 0.00 10.21 10.86 0.00 10.96 Below 2 kV 10.21 0.00 10.21 10.86 0.00 10.96 Below 2 kV 2.80 0.00 2.80 4.47 0.00 4.47 Voltage Discount, Hourly Fates - % From 2 kV to 50 kV 0.00%							
Below 2 kV		0.01289	Variable*	Variable*	0.0149	9 Variable*	Variable*
From 2 kV to 50 kV 278 69 0.00 278 69 291.00 0.00 291.00 2,322.25 Facilities Related Demand Charge - SkW Below 2 kV 10.77 0.00 10.77 11.70 0.00 11.70 From 2 kV to 50 kV 2.80 0.00 2.80 4.47 0.00 10.96 Above 50 kV 2.80 0.00 2.80 4.47 0.00 4.47 Voltage Discount, Hourly Rates - % From 2 kV to 50 kV 0.00% 0.00		459.04	0.00	459.04	542.25	. 0.00	542.25
## Above 50 kV							
Below 2 kW 10.77 0.00 10.77 11.70 0.00 11.70 11.70 0.00 11.70 11.70 0.00 10.96 0.00 10.96 above 50 kV 2.80 0.00 2.80 4.47 0.00 4.47 Voltage Discount, Hourly Rattes - W From 2 kV to 50 kV 0.00% 0							
From 2 kV to 50 kV 2.80 0.00 1.021 10.96 0.00 10.96 4.47 0.00 4.47 Voltage Discount, Hourly Rates - % From 2 kV to 50 kV 2.80 0.00 2.80 0.00% 0.	Facilities Related Demand Charge - \$/kW						
above 50 kV V 2.80 0.00 2.80 4.47 0.00 4.47 Voltage Discount, Horbyr Rates - % From 2 kV to 50 kV above 50 kV, but below 220 kV 0.00% 0.0							
Voltage Discount, Hourly Rates - % From 2 kV to 50 kV above 50 kV, but below 220 kV 0.00%							
From 2 kV to 50 kV but below 220 kV above 50 kV, but below 220 kV at 220 kV above 50 kV above 60 kV above 50 kV above 60 kV above 50 kV above 50 kV above 60 kV above 50 kV above 60		2.00	0.00	2.00	4.47	0.00	4.47
above 50 kV, but below 220 kV		0.00%	0.00%	0.00%	0.009	6 0.00%	0.00%
Voltage Discount, Facility-Related Demand - % at 20 kV 100.00%		0.00%	0.00%	0.00%	0.009	6 0.00%	0.00%
A		0.00%	-1.21%	-1.21%	0.009	6 -1.21%	-1.21%
Power Factor Adjustment - \$/kVA		100.000/			400.000	,	100.000/
Greater than 50 kV 50 kV or less 0.18 0.00 0.20 0.32 0.32 0.32 0.32 50 kV or less 50 kV or less 0.18 0.00 0.18 0.27 0.27 0.27 0.27 0.27 0.27 0.27 0.27		100.00%)		100.00%	' 0	100.00%
P Option - \$I/kW (Applicable: Average kW demand)	•	0.20	0.00	0.20	0.32	2	0.32
P Option - \$fkW (Applicable: Average kW demand)	50 kV or less	0.18	0.00	0.18	0.27	,	0.27
P Option - \$/kW (Applicable: Average kW demand) Option A BIP Option Credit (\$/kW) Below 2 kV - Summer Average On Peak (5.50) 0.00 (5.50) (6.45) (6.45) Winter Average Mid - Peak (2.02) 0.00 (2.02) (1.32) (1.32) Excess Energy Charge - \$/kWh 10.21374 0.00000 10.21374 13.90079 13.90079 From 2 kV to 50 kV - Summer Average On Peak (17.48) 0.00 (17.48) (20.74) (20.74) Summer Average Mid - Peak (5.40) 0.00 (5.40) (6.12) (6.12) Winter Average Mid - Peak (1.98) 0.00 (1.98) (1.28) (1.28) Excess Energy Charge - \$/kWh 9.99551 0.00000 9.99551 13.61036 13.61036 above 50 kV - Summer Average Mid - Peak (5.22) 0.00 (5.22) (5.56) (5.56) Winter Average Mid - Peak (5.22) 0.00 (5.22) (5.56) (5.56) Winter Average Mid - Peak (5.22) 0.00 (6.22) (6.02) (6.02) Winter Average Mid - Peak (1.90) 0.00 (1.90) (1.13) (1.13) Excess Energy Charge - \$/kWh 9.63234 0.00000 9.63234 13.09434 13.09434 Option B BIP Option Credit (\$/kW) Below 2 kV - Summer Average On Peak (16.45) 0.00 (16.45) (19.74) (19.74) Summer Average Mid - Peak (5.02) 0.00 (5.02) (6.02) (6.02) Winter Average Mid - Peak (1.93) 0.00 (1.93) (1.22) (1.22) Excess Energy Charge - \$/kWh 10.21374 0.00000 10.21374 12.96442 12.96442 From 2 kV to 50 kV - Summer Average On Peak (16.10) 0.00 (1.93) (1.22) (1.22) Excess Energy Charge - \$/kWh 10.21374 0.00000 10.21374 12.96442 12.96442 From 2 kV to 50 kV - Summer Average On Peak (4.92) 0.00 (4.92) (5.70) (5.70) Winter Average Mid - Peak (4.92) 0.00 (1.93) (1.19) (1.931) Excess Energy Charge - \$/kWh 9.99551 0.0000 9.99551 12.69398 12.69398 above 50 kV - Summer Average Mid - Peak (4.52) 0.00 (1.552) (18.34) (18.34) Summer Average Mid - Peak (4.52) 0.00 (1.552) (18.34) (18.34) Summer Average Mid - Peak (4.52) 0.00 (1.552) (18.34) (18.34) Summer Average Mid - Peak (4.52) 0.00 (1.552) (18.34) (18.34)	D Schedules for PTD-2 & DA_PTD						
Option A BIP Option Credit (\$/KW) Below 2 kV - Summer Average On Peak Summer Average Mid - Peak (5.50) 0.00 (5.50) (6.45) (6.45) (6.45) (6.45) (6.45) (6.45) (6.45) Winter Average Mid - Peak Wide A Peak (2.02) 0.00 (2.02) (1.32) (1.32) (1.32) (1.32) (1.32) (1.32) (1.32) (1.32) (1.32) Excess Energy Charge - \$/kWh 10.21374 0.00000 10.21374 13.90079 13.90079 13.90079 13.90079 From 2 kV to 50 kV - Summer Average Mid - Peak Summer Average Mid - Peak (1.48) 0.00 (5.40) (6.12) (6	To Schedules for KH -2 & FA-KH						
BIP Option Credit (\$/kW) Below 2 kV - Summer Average On Peak (5.50) 0.00 (5.50) (6.45							
Below 2 kV - Summer Average On Peak (17.89) 0.00 (17.89) (21.11) (21.11) Summer Average Mid - Peak (5.50) 0.00 (5.50) (6.45) (6.45) (6.45) (6.45) (1.32)	•						
Summer Average Mid - Peak (5.50) 0.00 (5.50) (6.45) (6.45) Winter Average Mid - Peak (2.02) 0.00 (2.02) (1.32) (1.32) (1.32) Excess Energy Charge - \$/kWh 10.21374 0.00000 10.21374 13.90079 13.90079 From 2 kV to 50 kV - Summer Average On Peak (17.48) 0.00 (17.48) (20.74) (20.74) Summer Average Mid - Peak (5.40) 0.00 (5.40) (6.12) (6.12) (6.12) Winter Average Mid - Peak (1.98) 0.00 (1.98) (1.28) (1.28) Excess Energy Charge - \$/kWh 9.99551 0.00000 9.99551 13.61036 13.61036 above 50 kV - Summer Average On Peak (16.84) 0.00 (16.84) (19.56) (19.56) Summer Average Mid - Peak (5.22) 0.00 (5.22) (5.56) (5.56) (5.56) Winter Average Mid - Peak (1.90) 0.00 (1.90) (1.13) (1.13) Excess Energy Charge - \$/kWh 9.63234 0.00000 9.63234 13.09434 13.09434 Option B BIP Option Credit (\$/kW) Below 2 kV - Summer Average On Peak (5.02) 0.00 (5.02) (6.02) (6.02) Winter Average Mid - Peak (5.02) 0.00 (5.02) (6.02) (6.02) (6.02) Excess Energy Charge - \$/kWh 10.21374 0.00000 10.21374 12.96442 12.96442 From 2 kV to 50 kV - Summer Average On Peak (16.10) 0.00 (16.10) (19.31) (19.31) Summer Average Mid - Peak (4.92) 0.00 (4.92) (5.70) (5.70) (5.70) Winter Average Mid - Peak (1.99) 0.00 (1.89) (1.19) (1.19) (1.19) Excess Energy Charge - \$/kWh 9.99551 0.00000 9.99551 12.69398 12.69398 above 50 kV - Summer Average On Peak (1.552) 0.000 (1.85) (1.834) (1.834) Summer Average Mid - Peak (1.59) 0.000 (1.552) (18.34) (1.834) Summer Average Mid - Peak (1.59) 0.000 (1.552) (18.34) (1.89) (1.19) (1.19)		(17.90)	0.00	(17.90)	(21.11	١	(21.11)
Winter Average Mid - Peak (2.02) 0.00 (2.02) (1.32) (1							
Excess Energy Charge - \$/kWh 10.21374 0.00000 10.21374 13.90079 13.90079 From 2 kV to 50 kV - Summer Average On Peak (17.48) 0.00 (17.48) (20.74) (20.74) Summer Average Mid - Peak (5.40) 0.00 (5.40) (6.12) (6.12) Winter Average Mid - Peak (1.98) 0.00 (1.98) (1.28) (1.28) Excess Energy Charge - \$/kWh 9.99551 0.0000 9.99551 13.61036 13.61036 above 50 kV - Summer Average On Peak (16.84) 0.00 (16.84) (19.56) (19.56) Summer Average Mid - Peak (5.22) 0.00 (5.22) (5.56) (5.56) Winter Average Mid - Peak (1.90) 0.00 (1.90) (1.13) (1.13) Excess Energy Charge - \$/kWh 9.63234 0.00000 9.63234 13.09434 13.09434 Option B BIP Option Credit (\$/KW) Below 2 kV - Summer Average On Peak (16.45) 0.00 (16.45) (19.74) (19.74) Summer Average Mid - Peak (5.02) 0.00 (5.02) (6.02) (6.02) Winter Average Mid - Peak (1.93) 0.00 (10.93) (1.22) (1.22) Excess Energy Charge - \$/kWh 10.21374 0.00000 10.21374 12.96442 From 2 kV to 50 kV - Summer Average On Peak (16.10) 0.00 (16.10) (19.31) (19.31) Summer Average Mid - Peak (1.99) 0.00 (18.9) (1.19) (1.93) Excess Energy Charge - \$/kWh 9.99551 0.0000 9.99551 12.69398 12.69398 above 50 kV - Summer Average On Peak (1.552) 0.00 (15.52) (18.34) (18.34) Summer Average Mid - Peak (1.552) 0.00 (15.52) (18.34) (18.34) Summer Average Mid - Peak (1.552) 0.00 (15.52) (18.34) (18.34) Summer Average Mid - Peak (4.74) 0.00 (4.74) (5.21) (5.21)	-				•		
Summer Average Mid - Peak (5.40) 0.00 (5.40) (6.12) (6.12) (6.12) Winter Average Mid - Peak (1.98) 0.00 (1.98) (1.28) (1.28) (1.28) Excess Energy Charge - \$/kWh 9.99551 0.00000 9.99551 13.61036 13.61036 13.61036	_				•		
Summer Average Mid - Peak (5.40) 0.00 (5.40) (6.12) (6.12) (6.12) Winter Average Mid - Peak (1.98) 0.00 (1.98) (1.29) (1.29) (1.							
Winter Average Mid - Peak (1.98) 0.00 (1.98) (1.28) (1.28) (1.28) Excess Energy Charge - \$/kWh 9.99551 0.00000 9.99551 13.61036 13.61036 13.61036 above 50 kV - Summer Average On Peak (16.84) 0.00 (16.84) (19.56) (1							
Excess Energy Charge - \$/kWh 9.99551 0.00000 9.99551 13.61036 13.61036 13.61036 above 50 kV - Summer Average On Peak (16.84) 0.00 (16.84) (19.56) (19.56) (19.56) Summer Average Mid - Peak (5.22) 0.00 (5.22) (5.56) (5.56) (5.56) Winter Average Mid - Peak (1.90) 0.00 (1.90) (1.13) (1.13) Excess Energy Charge - \$/kWh 9.63234 0.00000 9.63234 13.09434 13.09							
above 50 kV - Summer Average On Peak (16.84) 0.00 (16.84) (19.56) (19.56) Summer Average Mid - Peak (5.22) 0.00 (5.22) (5.56) (5.56) (5.56) Winter Average Mid - Peak (1.90) 0.00 (1.90) (1.13) (1.13) Excess Energy Charge - \$/kWh 9.63234 0.00000 9.63234 13.09434 13.09434 13.09434 Option B BIP Option Credit (\$/kW) Below 2 kV - Summer Average On Peak (5.02) 0.00 (16.45) (19.74) (19.74) (19.74) Summer Average Mid - Peak (5.02) 0.00 (5.02) (6.02) (6.02) (6.02) Winter Average Mid - Peak (1.93) 0.00 (1.93) (1.22) (1.22) Excess Energy Charge - \$/kWh 10.21374 0.00000 10.21374 12.96442 12.96442 From 2 kV to 50 kV - Summer Average On Peak (16.10) 0.00 (16.10) (19.31) (19.31) Summer Average Mid - Peak (4.92) 0.00 (4.92) (5.70) (5.70) Winter Average Mid - Peak (1.89) 0.00 (1.89) (1.19) (1.19) Excess Energy Charge - \$/kWh 9.99551 0.00000 9.99551 12.69398 12.69398 above 50 kV - Summer Average On Peak (15.52) 0.00 (15.52) (18.34) (18.34) Summer Average Mid - Peak (4.74) 0.00 (4.74) (5.21) (5.21)	<u> </u>						
Summer Average Mid - Peak (5.22) 0.00 (5.22) (5.56) (5.56) (5.56) Winter Average Mid - Peak (1.90) 0.00 (1.90) (1.13) (1.13) (1.13) Excess Energy Charge - \$/kWh 9.63234 0.00000 9.63234 13.0943					2.2.300		
Winter Average Mid - Peak (1.90) 0.00 (1.90) (1.13) (1.13) (1.13) Excess Energy Charge - \$/kWh 9.63234 0.00000 9.63234 13.09434 13.09434 13.09434 Option B BIP Option Credit (\$/kW) Below 2 kV - Summer Average On Peak (5.02) 0.00 (5.02) (6	-	(16.84)		(16.84)	(19.56	j)	(19.56)
Description Part							
Option B BIP Option Credit (\$/KW) Below 2 kV - Summer Average On Peak (16.45) 0.00 (16.45) (19.74) (19.74) Summer Average Mid - Peak (5.02) 0.00 (5.02) (6.02) (6.02) Winter Average Mid - Peak (1.93) 0.00 (1.93) (1.22) (1.22) Excess Energy Charge - \$/kWh 10.21374 0.00000 10.21374 12.96442 12.96442 From 2 kV to 50 kV - Summer Average On Peak (16.10) 0.00 (16.10) (19.31) (19.31) Summer Average Mid - Peak (4.92) 0.00 (4.92) (5.70) (5.70) Winter Average Mid - Peak (1.89) 0.00 (1.89) (1.19) (1.19) Excess Energy Charge - \$/kWh 9.99551 0.00000 9.99551 12.69398 12.69398 above 50 kV - Summer Average On Peak (15.52) 0.00 (15.52) (18.34) (18.34) Summer Average Mid - Peak (4.74) 0.00 (4.74) (5.21) (5.21)	<u> </u>						
BIP Option Credit (\$/kW) Below 2 kV - Summer Average On Peak (16.45) 0.00 (16.45) (19.74) (19.74) Summer Average Mid - Peak (5.02) 0.00 (5.02) (6.02) (6.02) (6.02) Winter Average Mid - Peak (1.93) 0.00 (1.93) (1.22) (1.22) Excess Energy Charge - \$/kWh 10.21374 0.00000 10.21374 12.96442 12.96442 From 2 kV to 50 kV - Summer Average On Peak (16.10) 0.00 (16.10) (19.31) (19.31) Summer Average Mid - Peak (4.92) 0.00 (4.92) (5.70) (5.70) Winter Average Mid - Peak (1.89) 0.00 (1.89) (1.19) (1.19) Excess Energy Charge - \$/kWh 9.99551 0.00000 9.99551 12.69398 12.69398 above 50 kV - Summer Average On Peak (15.52) 0.00 (15.52) (18.34) (18.34) Summer Average Mid - Peak (4.74) 0.00 (4.74) (5.21) (5.21)	Excess Energy Charge - \$/kWh	9.63234	0.00000	9.63234	13.09434		13.09434
Below 2 kV - Summer Average On Peak (16.45) 0.00 (16.45) (19.74) (19.74) (19.74) Summer Average Mid - Peak (5.02) 0.00 (5.02) (6.02) (6.02) (6.02) Winter Average Mid - Peak (1.93) 0.00 (1.93) (1.22) (1.22) Excess Energy Charge - \$/kWh 10.21374 0.00000 10.21374 12.96442 12.96442 From 2 kV to 50 kV - Summer Average On Peak (16.10) 0.00 (16.10) (19.31) (19.31) (19.31) Summer Average Mid - Peak (4.92) 0.00 (4.92) (5.70) (5.70) Winter Average Mid - Peak (1.89) 0.00 (1.89) (1.19) (1.19) Excess Energy Charge - \$/kWh 9.99551 0.00000 9.99551 12.69398 12.69398 above 50 kV - Summer Average On Peak (15.52) 0.00 (15.52) (18.34) (18.34) Summer Average Mid - Peak (4.74) 0.00 (4.74) (5.21) (5.21)	Option B						
Summer Average Mid - Peak (5.02) 0.00 (5.02) (6.02) (6.02) Winter Average Mid - Peak (1.93) 0.00 (1.93) (1.22) (1.22) Excess Energy Charge - \$/kWh 10.21374 0.00000 10.21374 12.96442 12.96442 From 2 kV to 50 kV - Summer Average On Peak (16.10) 0.00 (16.10) (19.31) (19.31) Summer Average Mid - Peak (4.92) 0.00 (4.92) (5.70) (5.70) Winter Average Mid - Peak (1.89) 0.00 (1.89) (1.19) (1.19) Excess Energy Charge - \$/kWh 9.99551 0.00000 9.99551 12.69398 12.69398 above 50 kV - Summer Average On Peak (15.52) 0.00 (15.52) (18.34) (18.34) Summer Average Mid - Peak (4.74) 0.00 (4.74) (5.21) (5.21)	·						
Winter Average Mid - Peak (1.93) 0.00 (1.93) (1.22) (1.22) (1.22) Excess Energy Charge - \$/kWh 10.21374 0.0000 10.21374 12.96442 12.96442 From 2 kV to 50 kV - Summer Average On Peak (16.10) 0.00 (16.10) (19.31) (19.31) Summer Average Mid - Peak (4.92) 0.00 (4.92) (5.70) (5.70) Winter Average Mid - Peak (1.89) 0.00 (1.89) (1.19) (1.19) Excess Energy Charge - \$/kWh 9.99551 0.00000 9.99551 12.69398 12.69398 above 50 kV - Summer Average On Peak (15.52) 0.00 (15.52) (18.34) (18.34) Summer Average Mid - Peak (4.74) 0.00 (4.74) (5.21)		(16.45)					(19.74)
Excess Energy Charge - \$/kWh 10.21374 0.00000 10.21374 12.96442 12.96442 12.96442 From 2 kV to 50 kV - Summer Average On Peak (16.10) 0.00 (16.10) (19.31) (19.31) Summer Average Mid - Peak (4.92) 0.00 (4.92) (5.70) (5.70) Winter Average Mid - Peak (1.89) 0.00 (1.89) (1.19) (1.19) Excess Energy Charge - \$/kWh 9.99551 0.00000 9.99551 12.69398 12.69398 above 50 kV - Summer Average On Peak (15.52) 0.00 (15.52) (18.34) (18.34) Summer Average Mid - Peak (4.74) 0.00 (4.74) (5.21) (5.21)	<u>o</u>						
From 2 kV to 50 kV - Summer Average On Peak (16.10) 0.00 (16.10) (19.31) (19.31) Summer Average Mid - Peak (4.92) 0.00 (4.92) (5.70) (5.70) (5.70) Winter Average Mid - Peak (1.89) 0.00 (1.89) (1.19) (1.19) Excess Energy Charge - \$/kWh 9.99551 0.00000 9.99551 12.69398 12.69398 above 50 kV - Summer Average On Peak (15.52) 0.00 (15.52) (18.34) (18.34) Summer Average Mid - Peak (4.74) 0.00 (4.74) (5.21) (5.21)	_						
Summer Average Mid - Peak (4.92) 0.00 (4.92) (5.70) (5.70) Winter Average Mid - Peak (1.89) 0.00 (1.89) (1.19) (1.19) Excess Energy Charge - \$/kWh 9.99551 0.00000 9.99551 12.69398 12.69398 above 50 kV - Summer Average On Peak (15.52) 0.00 (15.52) (18.34) (18.34) Summer Average Mid - Peak (4.74) 0.00 (4.74) (5.21) (5.21)	Excess Energy Charge - \$/kWh	10.21374	0.00000	10.21374	12.96442		12.90442
Summer Average Mid - Peak (4.92) 0.00 (4.92) (5.70) (5.70) Winter Average Mid - Peak (1.89) 0.00 (1.89) (1.19) (1.19) Excess Energy Charge - \$/kWh 9.99551 0.00000 9.99551 12.69398 12.69398 above 50 kV - Summer Average On Peak (15.52) 0.00 (15.52) (18.34) (18.34) Summer Average Mid - Peak (4.74) 0.00 (4.74) (5.21) (5.21)	From 2 kV to 50 kV - Summer Average On Peak	(16.10)	0.00	(16.10)	(19.31)	(19.31)
Excess Energy Charge - \$/kWh 9.99551 0.00000 9.99551 12.69398 12.69398 above 50 kV - Summer Average On Peak (15.52) 0.00 (15.52) (18.34) (18.34) Summer Average Mid - Peak (4.74) 0.00 (4.74) (5.21) (5.21)							
above 50 kV - Summer Average On Peak (15.52) 0.00 (15.52) (18.34) (18.34) Summer Average Mid - Peak (4.74) 0.00 (4.74) (5.21) (5.21)		(1.89)	0.00	(1.89)	(1.19))	(1.19)
Summer Average Mid - Peak (4.74) 0.00 (4.74) (5.21) (5.21)	Excess Energy Charge - \$/kWh	9.99551	0.00000	9.99551	12.69398	}	12.69398
Summer Average Mid - Peak (4.74) 0.00 (4.74) (5.21) (5.21)	above 50 kV - Summer Average On Peak	(15.52)	0.00	(15.52)	/18 2/	n.	(18 34)
				(1.82)			(1.05)

		Rates			Se				
		Effect	ve Decembe	r 2008		Settlement Rates			
	d of year 2009 revenue requirement as specified								
	ph 5.b.ii of Phase 2 Revenue Allocation t Agreement.	Deliver	Concretion	Total Data		Deliver	Concretion	Total Data	Total Rat
Settlement	Excess Energy Charge - \$/kWh	Delivery 9.63234	Generation 0.00000	Total Rate 9.63234	l	Delivery 12.21347	Generation	Total Rate 12.21347	Change 26.80
	Excess Energy energe water	0.00201	0.00000	0.00201		12.21011		12.21017	20.00
TOU-EV-3									
	Energy Charge - \$/kWh	0.05400	0.19715	0.05444		0.00400	0.24229	0.20225	20.65
	Summer Season On-Peak Off-Peak	0.05429 0.05429	0.19713	0.25144 0.12961		0.06106 0.06106	0.24229	0.30335 0.11740	-9.42
	Winter Season On-Peak	0.05429	0.10409	0.15838		0.06106	0.11324	0.17430	10.05
	Off-Peak	0.05429	0.07481	0.12910		0.06106	0.05187	0.11293	-12.52
	Customer Charge - \$/day	0.565	0.000	0.565		0.625		0.625	10.62
	TOU Meter Charge - \$/day-	0.252	0.000	0.252		0.366		0.366	45.24
TOU-EV-4									
	Energy Charge - \$/kWh	0.04040	0.40000	0.44500		0.04000	0.00050	0.00000	00.00
	Summer Season On-Peak Off-Peak	0.01613 0.01613	0.12986 0.04875	0.14599 0.06488		0.01969 0.01969	0.26253 0.05247	0.28222 0.07216	93.32 11.22
	on roun	0.01010	0.0.0.0	0.00100		0.0.000	0.00211	0.07210	
	Winter Season On-Peak	0.01613	0.06792	0.08405		0.01969	0.12233	0.14202	68.9
	Off-Peak	0.01613	0.04842	0.06455		0.01969	0.04815	0.06784	5.10
	Customer Charge - \$/meter/month	94.65	0.00	94.65		114.25		114.25	20.7
	Facilities Related Demand Charge - \$/kW	9.54	0.00	9.54		11.62		11.62	21.70
	Time Related								
	Demand Charge - \$/kW	0.00	18.62	18.62		0.00	21.11	21.11	13.3
	Voltage Discount, Facilities Related Demand - \$/kW								
	From 2 kV to 50 kV	(0.19)	0.00	(0.19)		(0.14)	0.00	(0.14)	26.3
	above 50 kV	(6.24)	0.00	(6.24)		(4.28)	0.00	(4.28)	31.4
	Voltage Discount, Time-Related Demand - \$/kW	0.00	(0.40)	(0.40)		0.00	(0.50)	(0.50)	40.0
	From 2 kV to 50 kV above 50 kV	0.00	(0.40) (1.04)	(0.40) (1.04)		0.00	(0.56) (1.55)	(0.56) (1.55)	-40.0 -49.0
	Voltage Discount, Energy - \$/kWh	0.00	(1.04)	(1.04)		0.00	(1.55)	(1.55)	-43.0
	From 2 kV to 50 kV	0.00000	(0.00199)	(0.00199)		0.00000	(0.00140)	(0.00140)	29.8
	above 50 kV	0.00000	(0.00433)	(0.00433)		0.00000	(0.00311)	(0.00311)	28.2
	Power Factor Adjustment - \$/kVA Greater than 50 kV	0.20	0.00	0.20		0.32	0.00	0.32	60.0
	50 kV or less	0.20	0.00	0.20		0.32	0.00	0.32	50.0
TOU-GS-3 (
	Energy Charge - \$/kWh Summer Season								
	On-Peak	0.01525	0.29651	0.31176		0.01848	0.25634	0.27482	-11.8
	Mid-peak	0.01525	0.12675	0.14200		0.01848	0.12074	0.13922	-1.9
	Off-Peak	0.01525	0.05341	0.06866		0.01848	0.06493	0.08341	21.4
	Winter Season								
	Mid-peak	0.01525	0.08943	0.10468		0.01848	0.06921	0.08769	-16.2
	Off-Peak	0.01525	0.05626	0.07151		0.01848	0.05402	0.07250	1.3
	Customer Charge - \$/month	367 02	0.00	367.02		443 75	0.00	443 75	20.0
	Customer Charge - \$/month Facilities Related	367.02	0.00	367.02		443.75	0.00	443.75	20.9

	Rates			Se			
	Effect	ve Decembe	r 2008				
Note: End of year 2009 revenue requirement as specified							
in Paragraph 5.b.ii of Phase 2 Revenue Allocation							Total Rate
Settlement Agreement.	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Change
TOU-GS-3 (Option B)							
Energy Charge - \$/kWh							
Summer Season							
On-Peak	0.01525	0.10180	0.11705	0.01848	0.12190	0.14038	19.93%
Mid-peak	0.01525	0.08084	0.09609	0.01848	0.08948	0.10796	12.35%
Off-Peak	0.01525	0.05341	0.06866	0.01848	0.06493	0.08341	21.48%
Winter Season							
Mid-peak	0.01525	0.08295	0.09820	0.01848	0.06921	0.08769	-10.70%
Off-Peak	0.01525	0.05626	0.07151	0.01848	0.05402	0.07250	1.38%
Customer Charge - \$/month	367.02	0.00	367.02	443.75	0.00	443.75	20.91%
Facilities Related	007.02	0.00	007.02	440.70	0.00	440.70	20.0170
Demand Charge - \$/kW	9.86	0.00	9.86	12.47	0.00	12.47	26.50%
Time Related Demand Charge - \$/kW							======
Summer Season							
On-Peak	0.00	16.36	16.36	0.00	16.01	16.01	-2.14%
Mid-Peak	0.00	5.61	5.61	0.00	3.80	3.80	-32.26%
Winter Season							
Mid-Peak	0.00	0.00					
Off-Peak	0.00	0.00					
Voltage Discount, Time-Related Demand - \$/kW							
From 2 kV to 50 kV	0.00	(0.39)	(0.39)	0.00	(0.23)	(0.23)	41.03%
above 50 kV	0.00	(1.04)	(1.04)	0.00	(0.64)	(0.64)	38.46%
TOU-GS-3 (Both Options) Voltage Discount, Facilities Related Demand - \$/kW							
From 2 kV to 50 kV	(0.19)	0.00	(0.19)	(0.18)	0.00	(0.18)	5.26%
above 50 kV	(6.25)	0.00	(6.25)	(5.66)	0.00	(5.66)	9.44%
Voltage Discount, Energy - \$/kWh	()		(-:)	()		(====)	2,
From 2 kV to 50 kV	0.00000	(0.00199)	(0.00199)	0.00000	(0.00138)	(0.00138)	30.65%
above 50 kV	0.00000	(0.00433)	(0.00433)	0.00000	(0.00307)	(0.00307)	29.04%
Power Factor Adjustment - \$/kVA							
Greater than 50 kV	0.20	0.00	0.20	0.32	0.00	0.32	60.00%
50 kV or less	0.18	0.00	0.18	0.27	0.00	0.27	50.00%
CARE Energy Discount - %	100.00		100.00	100.00		100.00	0.00%

		Effecti	Rates ve Decembe	er 2008	Se	ettlement	Ra
		2	200020				
ote: End of year 2009 revenue req	uirement as specified						l
Paragraph 5.b.ii of Phase 2 Reven	ue Allocation	Dallacan	0	T-4-1 D-4-	Dallaran	0	l
Settlement Agreement. 'OU-8 Summer on- and mid-peak Ener	rgy Charges adjusted effect	Delivery ive 2009 (50% pt		Total Rate	Delivery lated Demand Char	Generation	
OU-8 (Below 2kV)				,		, ,	
Energy Charge - \$/kWh	Summer Season						
	On-Peak	0.01481	0.09517	0.10998	0.01785	0.12967	
	Mid-peak	0.01481	0.07552	0.09033	0.01785		
	Off-Peak Winter Season	0.01481	0.04978	0.06459	0.01785	0.05739	
	Mid-peak	0.01481	0.07750	0.09231	0.01785	0.07626	
	Off-Peak	0.01481	0.05247	0.06728	0.01785	0.05431	
Customer Charge - \$/month		458.04	0.00	458.04	542.25	0.00	
Facilities Related		400.04	0.00	400.04	042.20	0.00	
Demand Charge		10.77	0.00	10.77	11.70	0.00	
Time Related Demand Char	ge - \$/kW Summer Season						
	On-Peak	0.00	15.23	15.23	0.00	19.73	
	Mid-Peak	0.00	5.14	5.14	0.00	5.56	
	Winter Season						
	winter Season Mid-Peak	0.00			0.00	0.00	
	Off-Peak	0.00			0.00	0.00	
Power Factor Adjustment - \$	2/IA//A	0.18	0.00	0.18	0.27	0.00	
Fower Factor Adjustment - \$	/KVA	0.16	0.00	0.16	0.27	0.00	
-8 (From 2 kV to 50 kV)							
Energy Charge - \$/kWh	Summer Season						
	On-Peak	0.01434	0.09652	0.11086	0.01734	0.09348	
	Mid-peak	0.01434	0.07662	0.09096	0.01734		
	Off-Peak	0.01434	0.05049	0.06483	0.01734	0.05596	
	Winter Season Mid-peak	0.01434	0.07864	0.09298	0.01734	0.07431	
	Off-Peak	0.01434	0.05324	0.06758	0.01734		
Customer Charge - \$/month		275.69	0.00	275.69	291.00	0.00	
Facilities Related		275.69	0.00	275.09	291.00	0.00	
Demand Charge		10.21	0.00	10.21	10.96	0.00	
Time Related Demand Char	ge - \$/kW Summer Season						
	On-Peak	0.00	15.48	15.48	0.00	23.82	
	Mid-Peak	0.00	5.24	5.24	0.00	6.68	
	Winter Season						
	winter Season Mid-Peak	0.00			0.00	0.00	
	Off-Peak	0.00			0.00	0.00	
Power Factor Adjustment - \$	Σ/ Ι -\/Δ	0.18	0.00	0.10	0.27	0.00	0
i ower i actor Aujustinelit - \$	MIXVI L	0.10	0.00	0.18	0.27	0.00	U
-8 (Above 50 kV)							
Energy Charge - \$/kWh	Summer Season						
	On-Peak	0.01289	0.07500	0.08789	0.01499	0.08456	0.099
	Mid-peak	0.01289	0.05952	0.07241	0.01499	0.06754	0.08
	Off-Peak Winter Season	0.01289	0.03911	0.05200	0.01499	0.04695	0.06
	Winter Season Mid-peak	0.01289	0.06123	0.07412	0.01499	0.06565	0.080
	Off-Peak	0.01289	0.04137	0.05426	0.01499		0.061
Customer Charge - \$/month Facilities Related		2,427.22	0.00	2,427.22	2,232.25	0.00	2,232.
Pacilities Related Demand Charge	e - \$/kW	2.80	0.00	2.80	4.47	0.00	4
Time Related Demand Char	ge - \$/kW						
	Summer Season	0.00	10.00	12.22	0.00	20.20	20
	On-Peak Mid-Peak	0.00	12.22 4.21	4.21	0.00 0.00	20.26 5.35	20.: 5.:
					2.30		2.0
	Winter Season	0.00			0.00	0.00	0.0
	Mid-Peak Off-Peak	0.00 0.00			0.00 0.00	0.00	0.0 0.0
Power Factor Adjustment - \$	S/kVA	0.20	0.00	0.20	0.32	0.00	0.3

Rates Settlement Rates Effective December 2008 Note: End of year 2009 revenue requirement as specified in Paragraph 5.b.ii of Phase 2 Revenue Allocation Total Rate Settlement Agreement. Generation Total Rate Delivery Generation Total Rate Change Delivery Voltage Discount, 220 kV and above -109.47% Facilities Related Demand - \$/kW (0.95)0.00 (0.95)(1.99)0.00 (1.99)Time-Related Demand - \$/kW 0.00 (0.09)(0.09)0.00 (0.15)(0.15)-66.67% Summer Energy - \$/kWh 0.00000 (0.00087)(0.00087)0 (0.00066)(0.00066)24.14% TOU-8 Summer on- and mid-peak Energy Charges adjusted effective 2011 (100% phase-in of Standby Time-Related Demand Charges, Paragraph 4.d.4) TOU-8 (Below 2kV) Energy Charge - \$/kWh Summer Season On-Peak 0.01481 0.09517 0.10998 0.01785 0.13015 0.14800 34.57% Mid-peak 0.01481 0.07552 0.09033 0.01785 0.08550 0.10335 14.42% Off-Peak 0.01481 0.04978 0.06459 0.01785 0.05739 0.07524 16.50% Winter Season Mid-peak 0.01481 0.07750 0.09231 0.01785 0.07626 0.09411 1.96% Off-Peak 0.01481 0.05247 0.06728 0.01785 0.05431 0.07216 7.26% Customer Charge - \$/month 458.04 0.00 458.04 542.25 0.00 542.25 18.38% Facilities Related Demand Charge - \$/kW 10.77 0.00 10.77 11.70 0.00 11.70 8.64% Time Related Demand Charge - \$/kW Summer Season On-Peak 0.00 15.23 15.23 0.00 19.73 19.73 29.55% Mid-Peak 0.00 5.14 5.14 0.00 5.56 5.56 8.17% Winter Season Mid-Peak 0.00 0.00 0.00 0.00 Off-Peak 0.00 0.00 0.00 0.00 Power Factor Adjustment - \$/kVA 0.18 0.00 0.18 0.27 0.00 0.27 50.00% TOU-8 (From 2 kV to 50 kV) Energy Charge - \$/kWh Summer Season On-Peak 0.01434 0.09652 0.11086 0.01734 0.09622 0.11356 2.44% Mid-peak 0.01434 0.07662 0.09096 0.01734 0.07866 0.09600 5.55% Off-Peak 0.01434 0.05049 0.06483 0.01734 0.05596 0.07330 13.07% Winter Season Mid-peak 0.01434 0.07864 0.09298 0.01734 0.07431 0.09165 -1.43% Off-Peak 0.01434 0.05324 0.06758 0.01734 0.05222 0.06956 2.94% Customer Charge - \$/month 291.00 5.55% 275.69 0.00 275.69 291.00 0.00 Facilities Related Demand Charge - \$/kW 7.36% 10.21 0.00 10.21 10.96 0.00 10.96 Time Related Demand Charge - \$/kW Summer Season On-Peak 0.00 15.48 15.48 0.00 23.82 23.82 53.88% Mid-Peak 5.24 5.24 6.68 27.48% 0.00 0.00 6.68 Winter Season Mid-Peak 0.00 0.00 0.00 0.00 Off-Peak 0.00 0.00 0.00 0.00 Power Factor Adjustment - \$/kVA 0.00 0.18 0.00 0.27 50.00%

0.18

0.27

		Rates		Settlement Rates				
	Effecti	ive Decembe	er 2008					
Note: End of year 2009 revenue requirement as specified								
in Paragraph 5.b.ii of Phase 2 Revenue Allocation								Total Rate
Settlement Agreement.	Delivery	Generation	Total Rate		Delivery	Generation	Total Rate	Change
TOU-8 (Above 50 kV) Energy Charge - \$/kWh								
Summer Season								
On-Peak	0.01289	0.07500	0.08789		0.01499	0.09021	0.10520	19.70%
Mid-peak	0.01289	0.05952	0.07241		0.01499	0.06975	0.08474	17.03%
Off-Peak	0.01289	0.03911	0.05200		0.01499	0.04695	0.06194	19.12%
Winter Season								
Mid-peak	0.01289	0.06123	0.07412		0.01499	0.06565	0.08064	8.80%
Off-Peak	0.01289	0.04137	0.05426		0.01499	0.04663	0.06162	13.57%
Customer Charge - \$/month Facilities Related	2,427.22	0.00	2,427.22		2,232.25	0.00	2,232.25	-8.03%
Demand Charge - \$/kW Time Related Demand Charge - \$/kW	2.80	0.00	2.80		4.47	0.00	4.47	59.78%
Summer Season								
On-Peak	0.00	12.22	12.22		0.00	20.26	20.26	65.79%
Mid-Peak	0.00	4.21	4.21		0.00	5.35	5.35	27.08%
Winter Season								
Mid-Peak	0.00				0.00	0.00	0.00	
Off-Peak	0.00				0.00	0.00	0.00	
Power Factor Adjustment - \$/kVA	0.20	0.00	0.20		0.32	0.00	0.32	60.00%
Voltage Discount, 220 kV and above								
Facilities Related Demand - \$/kW	(0.95)	0.00	(0.95)		(1.99)	0.00	(1.99)	-109.47%
Time-Related Demand - \$/kW								
Summer	0.00	(0.09)	(0.09)		0.00	(0.15)	(0.15)	-66.67%
Energy - \$/kWh	0.00000	(0.00087)	(0.00087)		0	(0.00066)	(0.00066)	24.14%
FOU-8 Summer on- and mid-peak Energy Charges adjusted effecti	ve 2009 (50% pł	nase-in of Sta	ındby Time-Re	lated I	Demand Charg	es, Paragrap	oh 4.d.4)	
TOU-8-Backup (Below 2kV)								
Energy Charge - \$/kWh								
Summer Season On-Peak	0.01481	0.09517	0.10998		0.01785	0.12967	0.14752	34.14%
Mid-peak	0.01481	0.09517	0.10998		0.01785	0.12967	0.14752	14.28%
Off-Peak	0.01481	0.04978	0.06459		0.01785	0.05739	0.07524	16.50%
Winter Season								
Mid-peak	0.01481	0.07750	0.09231		0.01785	0.07626	0.09411	1.96%
Off-Peak	0.01481	0.05247	0.06728		0.01785	0.05431	0.07216	7.26%
Customer Charge - \$/month	444.51	0.00	444.51		437.69	0.00	437.69	-1.53%
Time Related Demand Charge - \$/kW								
Summer Season								
On-Peak	0.00	15.23	15.23		0.00	19.73	19.73	29.55%
Mid-Peak	0.00	5.14	5.14		0.00	5.56	5.56	8.17%
Winter Season								
Mid-Peak	0.00				0.00	0.00	0.00	
Off-Peak	0.00				0.00	0.00	0.00	
Dougs Footor Adjustment 6/13/A	0.18	0.00	0.18		0.27	0.00	0.27	50.00%
Power Factor Adjustment - \$/kVA	0.18	0.00	0.18		0.27	0.00	0.27	50.00%

		Rates			Settlement Rates		
	Effecti	ve Decembe	er 2008		1		
Note: End of year 2009 revenue requirement as specified in Paragraph 5.b.ii of Phase 2 Revenue Allocation Settlement Agreement.	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Total Rate Change
TOU-8-Backup (From 2 kV to 50 kV)							
Energy Charge - \$/kWh Summer Season							
On-Peak	0.01434	0.09652	0.11086	0.0173	4 0.09348	0.11082	-0.03%
Mid-peak	0.01434	0.07662 0.05049	0.09096	0.0173		0.09528	4.75%
Off-Peak Winter Season	0.01434	0.05049	0.06483	0.0173	4 0.05596	0.07330	13.07%
Mid-peak	0.01434	0.07864	0.09298	0.0173	4 0.07431	0.09165	-1.43%
Off-Peak	0.01434	0.05324	0.06758	0.0173	4 0.05222	0.06956	2.94%
Customer Charge - \$/month	267.71	0.00	267.71	234.96	0.00	234.96	-12.23%
Time Related Demand Charge - \$/kW							
Summer Season	0.00	45.40	45.40	0.00		00.00	50.000/
On-Peak Mid-Peak	0.00	15.48 5.24	15.48 5.24	0.00		23.82 6.68	53.88% 27.48%
ind r san	0.00	0.21	0.2.	0.00	0.00	0.00	2670
Winter Season	0.00					2.22	
Mid-Peak Off-Peak	0.00			0.00		0.00	
Power Factor Adjustment - \$/kVA	0.18	0.00	0.18	0.27	0.00	0.27	50.00%
TOU-8-Backup (Above 50 kV) Energy Charge - \$/kWh							
Summer Season							
On-Peak Mid-peak	0.01289 0.01289	0.07500 0.05952	0.08789 0.07241	0.0149 0.0149		0.09955 0.08253	13.27% 13.98%
Off-Peak	0.01289	0.03932	0.07241	0.0149		0.06253	19.12%
Winter Season							
Mid-peak Off-Peak	0.01289 0.01289	0.06123 0.04137	0.07412 0.05426	0.0149 0.0149		0.08064 0.06162	8.80% 13.57%
Customer Charge - \$/month	2,355.83	0.00	2,355.83	1,801.69		1,801.69	-23.52%
Time Related Demand Charge - \$/kW							
Summer Season							
On-Peak	0.00	12.22	12.22	0.00	20.26	20.26	65.79%
Mid-Peak	0.00	4.21	4.21	0.00	5.35	5.35	27.08%
Winter Season							
Mid-Peak	0.00			0.00		0.00	
Off-Peak	0.00			0.00	0.00	0.00	
Power Factor Adjustment - \$/kVA	0.20	0.00	0.20	0.32	0.00	0.32	60.00%
Voltage Discount, 220 kV and above					.,		-
Facilities Related Demand - \$/kW Time-Related Demand - \$/kW	(0.95)	0.00	(0.95)	(1.99	0.00	(1.99)	-109.47%
Summer	0.00	(0.09)	(0.09)	0.00	(0.15)		-66.67%
Energy - \$/kWh	0.00000	(0.00087)	(0.00087)		0 (0.00092)	(0.00092)	-5.75%
TOU-8 Summer on- and mid-peak Energy Charges adjusted effective	ve 2011 (100% p	hase-in of St	andby Time-F	Related Demand Ch	arges, Paragra	aph 4.d.4)	
TOU-8-Backup (Below 2kV) Energy Charge - \$/kWh							
Summer Season							
On-Peak	0.01481	0.09517	0.10998	0.0178		0.14800	34.57%
Mid-peak Off-Peak	0.01481 0.01481	0.07552 0.04978	0.09033 0.06459	0.0178 0.0178		0.10335 0.07524	14.42% 16.50%
Winter Season							
Mid-peak	0.01481	0.07750	0.09231	0.0178		0.09411	1.96%
Off-Peak	0.01481	0.05247	0.06728	0.0178		0.07216	7.26%
Customer Charge - \$/month	444.51	0.00	444.51	437.69	0.00	437.69	-1.53%
Time Related Demand Charge - \$/kW							
Summer Season On-Peak	0.00	15.23	15.23	0.00	19.73	19.73	29.55%
Mid-Peak	0.00	5.14	5.14	0.00		5.56	8.17%
Winter Season							
winter Season Mid-Peak	0.00			0.00	0.00	0.00	
Off-Peak	0.00			0.00	0.00	0.00	

		Effectiv	Rates	r 2008		Settlement F	Rates
		Ellectiv	ve Decembe	1 2006			
nd of year 2009 revenue req aph 5.b.ii of Phase 2 Revent							
nt Agreement.	de Allocation	Delivery	Generation	Total Rate	Delive	ry Generation	on Total Rate
Power Factor Adjustment - \$	i/kVA	0.18	0.00	0.18		0.27 0.0	
nckup (From 2 kV to 50 kV)							
Energy Charge - \$/kWh	Summer Season						
	On-Peak	0.01434	0.09652	0.11086	0.0	1734 0.0962	2 0.11356
	Mid-peak	0.01434	0.07662	0.09096	0.0	1734 0.0786	6 0.09600
	Off-Peak	0.01434	0.05049	0.06483	0.0	1734 0.0559	6 0.07330
	Winter Season					.=	
	Mid-peak Off-Peak	0.01434 0.01434	0.07864 0.05324	0.09298 0.06758		1734 0.0743 1734 0.0522	
	Oll-Peak	0.01434	0.05524	0.00756	0.0	1734 0.0522	2 0.06956
Customer Charge - \$/month		267.71	0.00	267.71	23	4.96 0.0	0 234.96
Time Related Demand Charg	-						
	Summer Season	2.22	45.40	45.40		200 222	0 00.00
	On-Peak Mid-Peak	0.00 0.00	15.48 5.24	15.48 5.24		0.00 23.8 0.00 6.6	
	WIIU-FEAK	0.00	J.24	3.24		5.00 0.0	0.00
	Winter Season						
	Mid-Peak	0.00				0.00	
	Off-Peak	0.00				0.00	0.00
Dawer Faster Adjustment &	2//2//4	0.18	0.00	0.18		0.27 0.0	0 0.27
Power Factor Adjustment - \$	/KVA	0.16	0.00	0.10		5.27 0.0	0 0.27
ckup (Above 50 kV)							
Energy Charge - \$/kWh							
	Summer Season						
	On-Peak Mid-peak	0.01289 0.01289	0.07500 0.05952	0.08789 0.07241		1499 0.0902 1499 0.0697	
	Off-Peak	0.01289	0.03932	0.07241		1499 0.0697	
	Winter Season	0.01200	0.00011	0.00200	0.0		0.00.0.
	Mid-peak	0.01289	0.06123	0.07412	0.0	1499 0.0656	5 0.08064
	Off-Peak	0.01289	0.04137	0.05426	0.0	1499 0.0466	3 0.06162
		0.055.00	0.00	0.055.00	4.00		
Customer Charge - \$/month		2,355.83	0.00	2,355.83	1,80	1.69 0.0	0 1,801.69
Time Related Demand Charg	ge - \$/kW						
	Summer Season						
	On-Peak	0.00	12.22	12.22		0.00 20.2	
	Mid-Peak	0.00	4.21	4.21		0.00 5.3	5 5.35
	Winter Season						
	Mid-Peak	0.00				0.00 0.0	0.00
	Off-Peak	0.00				0.00	0.00
Power Factor Adjustment - \$	/kVA	0.20	0.00	0.20		0.32 0.0	0 0.32
Voltage Discount, 220 kV a	and above						
	s Related Demand - \$/kW	(0.95)	0.00	(0.95)	(1.99) 0.0	0 (1.99)
Time	e-Related Demand - \$/kW				·		
	Summer	0.00	(0.09)	(0.09)		0.00 (0.1	
	Energy - \$/kWh	0.00000	(0.00087)	(0.00087)		0 (0.0009	2) (0.00092)
r							
Capacity Res	servation Charge - \$/kW						
Capacity Not	500 kW or less	6.37	0.00	6.37		5.14 0.0	0 5.14
		0.07	0.00	6.37		5.14 0.0	0 5.14
	Below 2 kV	6.37					
	From 2 kV to 50 kV	6.28	0.00	6.28		4.89 0.0	
						4.89 0.0 1.25 0.0 0.65 0.0	0 1.25

					_				
			Rates			Se	ettlement Ra	tes	
		Effec	tive Decembe	er 2008					
Note: End of year 2009 revenue requirement a	e enocified								
in Paragraph 5.b.ii of Phase 2 Revenue Allocation									Total Rate
Settlement Agreement.		Delivery	Generation	Total Rate		Delivery	Generation	Total Rate	Change
•				!					
Backup Service									
Demand Charge - \$/kW		. 500/ 55 1/1							
<u>Summer Time-Related Demand Charges Effective</u> Summer Time Related Demand Charge		it 50% of final (I	Paragraph 4.0	<u>1.4)</u>					
Below 2 kV	- ψ/ΚΨΨ								
	On-Peak	0.00	11.63	11.63		0.00	16.16	16.16	38.969
	Mid-Peak	0.00	4.24	4.24		0.00	4.42	4.42	4.169
From 2 kV to 50 kV									
	On-Peak	0.00		11.87		0.00	18.63	18.63	56.91%
Above 50 but 4 220 lav	Mid-Peak	0.00	4.34	4.34		0.00	5.04	5.04	16.189
Above 50, but < 220 kV	On-Peak	0.00	8.61	8.61		0.00	16.03	16.03	86.15%
	Mid-Peak	0.00		3.31		0.00	3.77	3.77	13.77%
220 kV and above	.ma . can	3.00	5.01	5.01		5.00	5.77	3.77	.5.77
	On-Peak	0.00	8.45	8.45		0.00	15.86	15.86	87.74%
	Mid-Peak	0.00	3.24	3.24		0.00	3.73	3.73	15.05%
Summer Time-Related Demand Charges Effective		1 4.d.3.a)							
Summer Time Related Demand C Below 2 kV	narge - \$/kvv								
Delow 2 RV	On-Peak	0.00	11.63	11.63		0.00	12.59	12.59	8.27%
	Mid-Peak	0.00		4.24		0.00	3.27	3.27	-22.829
From 2 kV to 50 kV									
	On-Peak	0.00		11.87		0.00	13.43	13.43	13.15%
	Mid-Peak	0.00	4.34	4.34		0.00	3.40	3.40	-21.55%
Above 50, but < 220 kV	On-Peak	0.00	8.61	8.61		0.00	11.79	11.79	36.99%
	Mid-Peak	0.00		3.31		0.00	2.18	2.18	-34.08%
220 kV and above	Wild I Call	0.00	0.01	0.01		0.00	2.10	2.10	04.007
	On-Peak	0.00	8.45	8.45		0.00	11.67	11.67	38.16%
	Mid-Peak	0.00	3.24	3.24		0.00	2.16	2.16	-33.35%
TOU-8 Summer on- and mid-peak Energy Charges	adjusted effect	ve 2009 (50% p	hase-in of Sta	andby Time-Re	elated [Demand Charg	ges, Paragrap	<u>oh 4.d.4)</u>	
TOU-8 (Below 2kV) - Option A Energy Charge - \$/kWh									
Summer	Season								
- Canimor -	On-Peak					0.01785	0.31808	0.33593	
	Mid-peak					0.01785	0.12658	0.14443	
	Off-Peak					0.01785	0.05739	0.07524	
Winter Se									
	Mid-peak					0.01785		0.09411	
	Off-Peak					0.01785	0.05431	0.07216	
Customer Charge - \$/month						542.25	0.00	542.25	
Facilities Related						0.2.20	3.00	5.2.20	
Demand Charge - \$/kW						11.70	0.00	11.70	
Time Related Demand Charge - \$/kW									
Summer									
	On-Peak								
	Mid-Peak								
Winter Se	eason								
vviittei Se	Mid-Peak								
	Off-Peak								

0.27

0.27

0.00

1603188.v4 A-10

Power Factor Adjustment - \$/kVA

					1				
		Effec	Rates tive December	er 2008		Se	ettlement Ra	tes	
Note: End of year 2009 revenue requ									
in Paragraph 5.b.ii of Phase 2 Revenu Settlement Agreement.	e Allocation	Delivery	Generation	Total Rate		Delivery	Generation	Total Rate	Total Rate Change
TOU-8 (From 2 kV to 50 kV) - Option A		Delivery	Concration	Total Nate	1	Delivery	Concration	Total Nate	Onlange
Energy Charge - \$/kWh	Summer Season								
	On-Peak					0.01734	0.32057	0.33791	
	Mid-peak					0.01734		0.14294	
	Off-Peak Winter Season					0.01734	0.05596	0.07330	
	Mid-peak					0.01734		0.09165	
	Off-Peak					0.01734	0.05222	0.06956	
Customer Charge - \$/month						291.00	0.00	291.00	
Facilities Related	Ø#1.567					40.00	0.00	10.00	
Demand Charge Time Related Demand Charge						10.96	0.00	10.96	
Ç	Summer Season								
	On-Peak Mid-Peak								
	iviiu-reak								
	Winter Season								
	Mid-Peak Off-Peak								
	5.1. T 5d.1.								
Power Factor Adjustment - \$/l	kVA					0.27	0.00	0.27	
TOU-8 (Above 50 kV) - Option A									
Energy Charge - \$/kWh	0 0								
	Summer Season On-Peak					0.01499	0.26826	0.28325	
	Mid-peak					0.01499		0.11820	
	Off-Peak					0.01499	0.04695	0.06194	
	Winter Season Mid-peak					0.01499	0.06565	0.08064	
	Off-Peak					0.01499		0.06161	
Customer Charge - \$/month Facilities Related						2232.25	0.00	2232.25	
Demand Charge						4.47	0.00	4.47	
Time Related Demand Charge									
	Summer Season On-Peak								
	Mid-Peak								
	\A/i=4== C=====								
	Winter Season Mid-Peak								
	Off-Peak								
Power Factor Adjustment - \$/I	kVΔ					0.32	0.00	0.32	
·									
TOU-8 Summer on- and mid-peak Energy TOU-8 (Below 2kV) - Option A	y Charges adjusted effective	ve 2011 (100%	phase-in of S	tandby Time-I	Related	Demand Cha	rges, Paragra	aph 4.d.4)	
Energy Charge - \$/kWh									
	Summer Season								
	On-Peak Mid-peak					0.01785 0.01785		0.33641 0.14457	
	Off-Peak					0.01785		0.07524	
	Winter Season								
	Mid-peak Off-Peak					0.01785 0.01785		0.09411 0.07216	
	OII-Feak					0.01763	0.05451	0.07210	
Customer Charge - \$/month						542.25	0.00	542.25	
Facilities Related Demand Charge	- \$/kW					11.70	0.00	11.70	
Time Related Demand Charge						11.70	0.00	11.70	
	Summer Season								
	On-Peak Mid-Peak								
	IVIIU-F GAK								
	Winter Season								
	Mid-Peak Off-Peak								
	OII-F Bak								
Power Factor Adjustment - \$/l	kVA					0.27	0.00	0.27	

Total Rat Change 65 66 30 65 56 00
Change 65 66 30 65 56 00
Change 65 66 30 65 56 00
66 30 65 56
66 30 65 56
66 30 65 56
30 65 56 00
65 56 00
56 00
26
30
27
90
41
94
64
61
25
47
32
29
29
19)
39)
?9 62)
,
20
29 1 7)
,
22
22 20)
•
:7
57 02)
0.1 10 10 10 10 10 10 10 10 10 10 10 10 10

		Rates	S	ettlement Ra	tes	
		Effective December 2008				
I	I					
Note: End of year 2009 revenue requ	irement as specified					
in Paragraph 5.b.ii of Phase 2 Revenu						Total Rate
Settlement Agreement.		Delivery Generation Total Rate	Delivery	Generation	Total Rate	Change
GS-2 (TOU Option R)				•		
Energy Charge - \$/kWh						
	Summer Season					
	On-Peak		0.03950	0.34112	0.38062	
	Mid-peak		0.03950	0.13287	0.17237	
	Off-Peak		0.03950	0.05486	0.09436	
	Winter Season					
	Mid-peak		0.03950		0.11701	
	Off-Peak		0.03950	0.05195	0.09145	
Customer Charge - \$/month			114.25		114.25	
E TE BILLE IO	Φ /I 337		5.01		5.01	
Facilities Related Demand Charg	ge - \$/kW		5.81		5.81	
G: 1 M G : 6/ 4			(0.04)		(0.04)	
Single Phase Service - \$/month			(9.94)		(9.94)	
TOU CC 2 (O-4: P)						
TOU-GS-3 (Option R)						
Energy Charge - \$/kWh	Summer Season					
	On-Peak		0.03596	0.25634	0.29230	
	On-Peak Mid-peak		0.03596		0.29230	
	Off-Peak		0.03596		0.10089	
	Winter Season		0.03590	0.00493	0.10009	
	Winter Season Mid-peak		0.03596	0.06921	0.10517	
	Off-Peak		0.03596			
	OII-I GAR		0.03330	0.03402	0.00330	
Customer Charge - \$/month			443.75		443.75	
Facilities Related			110.10			
Demand Charge	- \$/kW		6.23		6.23	
Time Related Demand Charg						
	Summer Season					
	On-Peak				0.00	
	Mid-Peak				0.00	
	Winter Season					
	Mid-Peak					
	Off-Peak					
Voltage Discount, Time-Relat	ed Demand - \$/kW					
	From 2 kV to 50 kV					
	above 50 kV					
	gy Charges adjusted effecti	ve 2009 (50% phase-in of Standby Time-Rel	ated Demand Char	ges, Paragrap	<u>oh 4.d.4)</u>	
TOU-8 (Below 2kV) - Option R						
Energy Charge - \$/kWh						
	Summer Season					
	On-Peak		0.03174		0.34982	
	Mid-peak		0.03174		0.15832	
	Off-Peak		0.03174	0.05739	0.08913	
	Winter Season		0.001=	0.07000	0.40000	
	Mid-peak Off-Peak		0.03174 0.03174		0.10800 0.08605	
	Oir-Peak		0.03174	0.05431	0.0000	
Customer Charge - \$/month			542.25		542.25	
Facilities Related			042.20		J+2.20	
Pacilities Related Demand Charge	- \$/kW		5.85		5.85	
Time Related Demand Charg			5.00		5.05	
o Rolated Demand Charg	Summer Season					
	On-Peak					
	Mid-Peak					
	ma r oak					
	Winter Season					
	Mid-Peak					
	Off-Peak					
Power Factor Adjustment - \$/	kVA		0.27		0.27	
-						
TOU-8 (From 2 kV to 50 kV) - Option R						
Energy Charge - \$/kWh						
-	Summer Season					
	On-Peak		0.02937	0.32057	0.34994	
	Mid-peak		0.02937		0.15497	
	Off-Peak		0.02937			
	Winter Season					
	Mid-peak		0.02937	0.07431	0.10368	
	Off-Peak		0.02937	0.05222	0.08159	

Rates

Settlement Rates

		Effec	tive Decembe	er 2008		36		-	
	\neg	Liloo	T DOGGIIIDO	1 2000	1				
!									
Note: End of year 2009 revenue requirement as specifie	d								
in Paragraph 5.b.ii of Phase 2 Revenue Allocation									Total Rate
Settlement Agreement.		Delivery	Generation	Total Rate	J I	Delivery	Generation		Change
Customer Charge - \$/month						291.00		291.00	
Facilities Related						5.40		5.40	
Demand Charge - \$/kW Time Related Demand Charge - \$/kW						5.48		5.48	
Summer Season									
On-Pe	ak								
Mid-Pe									
Winter Season									
Mid-Pe	ak								
Off-Pe	ak								
Power Factor Adjustment - \$/kVA						0.27		0.27	
TOU 0 (4)									
TOU-8 (Above 50 kV) - Option R									
Energy Charge - \$/kWh Summer Season									
On-Pe	ak					0.01692	0.26826	0.28518	
Mid-pe						0.01692		0.12013	
Off-Pe						0.01692		0.06387	
Winter Season									
Mid-pe	ak					0.01692	0.06565	0.08257	
Off-Pe						0.01692	0.04662	0.06354	
Customer Charge - \$/month						2232.25		2232.25	
Facilities Related									
Demand Charge - \$/kW						3.48		3.48	
Time Related Demand Charge - \$/kW									
Summer Season On-Pe	al.								
Mid-Pe									
Wild-1 C	ak								
Winter Season									
Mid-Pe	ak								
Off-Pe	ak								
	uit								
	, un								
Power Factor Adjustment - \$/kVA	, un					0.32		0.32	
Power Factor Adjustment - \$/kVA									
Power Factor Adjustment - \$/kVA TOU-8 Summer on- and mid-peak Energy Charges adjusted		2011 (100%	phase-in of S	andby Time-l	Related				
Power Factor Adjustment - \$/kVA TOU-8 Summer on- and mid-peak Energy Charges adjusted TOU-8 (Below 2kV) - Option R		2011 (100%)	phase-in of S	andby Time-l	<u>Related</u>				
Power Factor Adjustment - \$/kVA TOU-8 Summer on- and mid-peak Energy Charges adjusted TOU-8 (Below 2kV) - Option R Energy Charge - \$/kWh		2011 (100%)	phase-in of S	andby Time-l	Related				
Power Factor Adjustment - \$/kVA TOU-8 Summer on- and mid-peak Energy Charges adjusted TOU-8 (Below 2kV) - Option R Energy Charge - \$/kWh Summer Season	effective	<u>2011 (100%</u>	phase-in of S	andby Time-l	<u>Related</u>	Demand Cha	rges, Paragra	ph 4.d.4)	
Power Factor Adjustment - \$/kVA TOU-8 Summer on- and mid-peak Energy Charges adjusted TOU-8 (Below 2kV) - Option R Energy Charge - \$/kWh Summer Season On-Pe	effective	2011 (100%	phase-in of S	andby Time-l	<u>Related</u>	Demand Cha 0.03174	rges, Paragra 0.31856	ph 4.d.4) 0.35030	
Power Factor Adjustment - \$/kVA TOU-8 Summer on- and mid-peak Energy Charges adjusted TOU-8 (Below 2kV) - Option R Energy Charge - \$/kWh Summer Season	effective eak eak	2011 (100%	phase-in of S	andby Time-i	<u>Related</u>	Demand Cha	0.31856 0.12672	ph 4.d.4)	
Power Factor Adjustment - \$/kVA TOU-8 Summer on- and mid-peak Energy Charges adjusted TOU-8 (Below 2kV) - Option R Energy Charge - \$/kWh Summer Season On-Pe Mid-pe Off-Pe	effective eak eak	2011 (100%)	phase-in of S	andby Time-I	<u>Related</u>	0.03174 0.03174	0.31856 0.12672	ph 4.d.4) 0.35030 0.15846	
Power Factor Adjustment - \$/kVA TOU-8 Summer on- and mid-peak Energy Charges adjusted TOU-8 (Below 2kV) - Option R Energy Charge - \$/kWh Summer Season On-Pe Mid-pe	effective eak eak eak	2011 (100%	phase-in of S	andby Time-I	<u>Related</u>	0.03174 0.03174	0.31856 0.12672 0.05739	ph 4.d.4) 0.35030 0.15846	
Power Factor Adjustment - \$/kVA TOU-8 Summer on- and mid-peak Energy Charges adjusted TOU-8 (Below 2kV) - Option R Energy Charge - \$/kWh Summer Season On-Pe Mid-pe Off-Pe Winter Season	effective eak eak eak	: <u>2011 (100%</u>	<u>phase-in of S</u>	andby Time-f	<u>Related</u>	0.03174 0.03174	0.31856 0.12672 0.05739 0.07626	0.35030 0.15846 0.08913	
Power Factor Adjustment - \$/kVA TOU-8 Summer on- and mid-peak Energy Charges adjusted TOU-8 (Below 2kV) - Option R Energy Charge - \$/kWh Summer Season On-Pe Mid-pe Off-Pe Winter Season Mid-pe Off-Pe	effective eak eak eak	2011 (100%)	ohase-in of S	andby Time-f	<u>Related</u>	0.03174 0.03174 0.03174 0.03174	0.31856 0.12672 0.05739 0.07626 0.05431	0.35030 0.15846 0.08913 0.10800 0.08605	
Power Factor Adjustment - \$/kVA TOU-8 Summer on- and mid-peak Energy Charges adjusted TOU-8 (Below 2kV) - Option R Energy Charge - \$/kWh Summer Season On-Pe Mid-pe Off-Pe Winter Season Mid-pe Off-Pe	effective eak eak eak	· 2011 (100%	ohase-in of S	andby Time-f	<u>Related</u>	0.03174 0.03174 0.03174 0.03174	0.31856 0.12672 0.05739 0.07626 0.05431	0.35030 0.15846 0.08913 0.10800	
Power Factor Adjustment - \$/kVA TOU-8 Summer on- and mid-peak Energy Charges adjusted TOU-8 (Below 2kV) - Option R Energy Charge - \$/kWh Summer Season On-Pe Mid-pe Off-Pe Winter Season Mid-pe Off-Pe Customer Charge - \$/month Facilities Related	effective eak eak eak	2011 (100%	phase-in of S	andby Time-l	Related	0.03174 0.03174 0.03174 0.03174 0.03174 542.25	0.31856 0.12672 0.05739 0.07626 0.05431	0.35030 0.15846 0.08913 0.10800 0.08605 542.25	
Power Factor Adjustment - \$/kVA TOU-8 Summer on- and mid-peak Energy Charges adjusted TOU-8 (Below 2kV) - Option R Energy Charge - \$/kWh Summer Season On-Pe Mid-pe Off-Pe Winter Season Mid-pe Off-Pe Customer Charge - \$/month Facilities Related Demand Charge - \$/kW	effective eak eak eak	2011 (100%	phase-in of S	andby Time-f	<u>Related</u>	0.03174 0.03174 0.03174 0.03174	0.31856 0.12672 0.05739 0.07626 0.05431	0.35030 0.15846 0.08913 0.10800 0.08605	
Power Factor Adjustment - \$/kVA TOU-8 Summer on- and mid-peak Energy Charges adjusted TOU-8 (Below 2kV) - Option R Energy Charge - \$/kWh Summer Season On-Pe Mid-pe Off-Pe Winter Season Mid-pe Off-Pe Customer Charge - \$/month Facilities Related Demand Charge - \$/kW Time Related Demand Charge - \$/kW	effective eak eak eak	2011 (100%)	phase-in of S	andby Time-f	<u>Related</u>	0.03174 0.03174 0.03174 0.03174 0.03174 542.25	0.31856 0.12672 0.05739 0.07626 0.05431	0.35030 0.15846 0.08913 0.10800 0.08605 542.25	
Power Factor Adjustment - \$/kVA TOU-8 Summer on- and mid-peak Energy Charges adjusted TOU-8 (Below 2kV) - Option R Energy Charge - \$/kWh Summer Season On-Pe Mid-pe Off-Pe Winter Season Mid-pe Off-Pe Customer Charge - \$/month Facilities Related Demand Charge - \$/kW Time Related Demand Charge - \$/kW Summer Season	eak eak eak eak eak	2011 (100%)	phase-in of S	andby Time-f	<u>Related</u>	0.03174 0.03174 0.03174 0.03174 0.03174 542.25	0.31856 0.12672 0.05739 0.07626 0.05431	0.35030 0.15846 0.08913 0.10800 0.08605 542.25	
Power Factor Adjustment - \$/kVA TOU-8 Summer on- and mid-peak Energy Charges adjusted TOU-8 (Below 2kV) - Option R Energy Charge - \$/kWh Summer Season On-Pe Mid-pe Off-Pe Winter Season Mid-pe Off-Pe Customer Charge - \$/month Facilities Related Demand Charge - \$/kW Time Related Demand Charge - \$/kW Summer Season On-Pe	eak eak eak eak eak eak	2011 (100%)	phase-in of S	andby Time-f	<u>Related</u>	0.03174 0.03174 0.03174 0.03174 0.03174 542.25	0.31856 0.12672 0.05739 0.07626 0.05431	0.35030 0.15846 0.08913 0.10800 0.08605 542.25	
Power Factor Adjustment - \$/kVA TOU-8 Summer on- and mid-peak Energy Charges adjusted TOU-8 (Below 2kV) - Option R Energy Charge - \$/kWh Summer Season On-Pe Mid-pe Off-Pe Winter Season Mid-pe Off-Pe Customer Charge - \$/month Facilities Related Demand Charge - \$/kW Time Related Demand Charge - \$/kW Summer Season	eak eak eak eak eak eak	2011 (100%	phase-in of S	andby Time-l	Related	0.03174 0.03174 0.03174 0.03174 0.03174 542.25	0.31856 0.12672 0.05739 0.07626 0.05431	0.35030 0.15846 0.08913 0.10800 0.08605 542.25	
Power Factor Adjustment - \$/kVA TOU-8 Summer on- and mid-peak Energy Charges adjusted TOU-8 (Below 2kV) - Option R Energy Charge - \$/kWh Summer Season On-Pe Mid-pe Off-Pe Winter Season Mid-pe Off-Pe Customer Charge - \$/month Facilities Related Demand Charge - \$/kW Time Related Demand Charge - \$/kW Summer Season On-Pe	eak eak eak eak eak eak	2011 (100%	phase-in of S	andby Time-l	Related	0.03174 0.03174 0.03174 0.03174 0.03174 542.25	0.31856 0.12672 0.05739 0.07626 0.05431	0.35030 0.15846 0.08913 0.10800 0.08605 542.25	
Power Factor Adjustment - \$/kVA TOU-8 Summer on- and mid-peak Energy Charges adjusted TOU-8 (Below 2kV) - Option R Energy Charge - \$/kWh Summer Season On-Pe Mid-pe Off-Pe Winter Season Mid-pe Off-Pe Customer Charge - \$/month Facilities Related Demand Charge - \$/kW Time Related Demand Charge - \$/kW Summer Season On-Pe Mid-Pe	eak eak eak eak eak eak	2011 (100%	phase-in of S	andby Time-F	<u>Related</u>	0.03174 0.03174 0.03174 0.03174 0.03174 542.25	0.31856 0.12672 0.05739 0.07626 0.05431	0.35030 0.15846 0.08913 0.10800 0.08605 542.25	
Power Factor Adjustment - \$/kVA TOU-8 Summer on- and mid-peak Energy Charges adjusted TOU-8 (Below 2kV) - Option R Energy Charge - \$/kWh Summer Season On-Pe Mid-pe Off-Pe Winter Season Mid-pe Off-Pe Customer Charge - \$/month Facilities Related Demand Charge - \$/kW Time Related Demand Charge - \$/kW Summer Season On-Pe Mid-Pe Mid-Pe	eak eak eak eak eak eak	2011 (100%	phase-in of S	andby Time-f	<u>Related</u>	0.03174 0.03174 0.03174 0.03174 0.03174 542.25	0.31856 0.12672 0.05739 0.07626 0.05431	0.35030 0.15846 0.08913 0.10800 0.08605 542.25	
Power Factor Adjustment - \$/kVA TOU-8 Summer on- and mid-peak Energy Charges adjusted TOU-8 (Below 2kV) - Option R Energy Charge - \$/kWh Summer Season On-Pe Mid-pe Off-Pe Winter Season Mid-pe Off-Pe Customer Charge - \$/month Facilities Related Demand Charge - \$/kW Time Related Demand Charge - \$/kW Summer Season On-Pe Mid-Pe Mid-Pe Off-Pe	eak eak eak eak eak eak	2011 (100%	phase-in of S	andby Time-f	Related	0.03174 0.03174 0.03174 0.03174 0.03174 542.25 5.85	0.31856 0.12672 0.05739 0.07626 0.05431	0.35030 0.15846 0.08913 0.10800 0.08605 542.25 5.85	
Power Factor Adjustment - \$/kVA TOU-8 Summer on- and mid-peak Energy Charges adjusted TOU-8 (Below 2kV) - Option R Energy Charge - \$/kWh Summer Season On-Pe Mid-pe Off-Pe Winter Season Mid-pe Off-Pe Customer Charge - \$/month Facilities Related Demand Charge - \$/kW Time Related Demand Charge - \$/kW Summer Season On-Pe Mid-Pe Winter Season Winter Season Mid-Pe Winter Season Mid-Pe	eak eak eak eak eak eak	2011 (100%	phase-in of S	andby Time-f	Related	0.03174 0.03174 0.03174 0.03174 0.03174 542.25	0.31856 0.12672 0.05739 0.07626 0.05431	0.35030 0.15846 0.08913 0.10800 0.08605 542.25	
Power Factor Adjustment - \$/kVA TOU-8 Summer on- and mid-peak Energy Charges adjusted TOU-8 (Below 2kV) - Option R Energy Charge - \$/kWh Summer Season On-Pe Mid-pe Off-Pe Winter Season Mid-pe Off-Pe Customer Charge - \$/month Facilities Related Demand Charge - \$/kW Time Related Demand Charge - \$/kW Summer Season On-Pe Mid-Pe Winter Season Mid-Pe Off-Pe	eak eak eak eak eak eak	2011 (100%	phase-in of S	andby Time-l	Related	0.03174 0.03174 0.03174 0.03174 0.03174 542.25 5.85	0.31856 0.12672 0.05739 0.07626 0.05431	0.35030 0.15846 0.08913 0.10800 0.08605 542.25 5.85	
Power Factor Adjustment - \$/kVA TOU-8 Summer on- and mid-peak Energy Charges adjusted TOU-8 (Below 2kV) - Option R Energy Charge - \$/kWh Summer Season On-Pe Mid-pe Off-Pe Winter Season Mid-pe Off-Pe Customer Charge - \$/month Facilities Related Demand Charge - \$/kW Time Related Demand Charge - \$/kW Summer Season On-Pe Mid-Pe Winter Season Mid-Pe Off-Pe Power Factor Adjustment - \$/kVA TOU-8 (From 2 kV to 50 kV) - Option R	eak eak eak eak eak eak	2011 (100%	phase-in of S	andby Time-l	Related	0.03174 0.03174 0.03174 0.03174 0.03174 542.25 5.85	0.31856 0.12672 0.05739 0.07626 0.05431	0.35030 0.15846 0.08913 0.10800 0.08605 542.25 5.85	
Power Factor Adjustment - \$/kVA TOU-8 Summer on- and mid-peak Energy Charges adjusted TOU-8 (Below 2kV) - Option R Energy Charge - \$/kWh Summer Season On-Pe Mid-pe Off-Pe Winter Season Mid-pe Off-Pe Customer Charge - \$/month Facilities Related Demand Charge - \$/kW Time Related Demand Charge - \$/kW Summer Season On-Pe Mid-Pe Winter Season On-Pe Mid-Pe Off-Pe Power Factor Adjustment - \$/kVA TOU-8 (From 2 kV to 50 kV) - Option R Energy Charge - \$/kWh	eak eak eak eak eak eak	2011 (100%	phase-in of S	andby Time-I	Related	0.03174 0.03174 0.03174 0.03174 0.03174 542.25 5.85	0.31856 0.12672 0.05739 0.07626 0.05431	0.35030 0.15846 0.08913 0.10800 0.08605 542.25 5.85	
Power Factor Adjustment - \$/kVA TOU-8 Summer on- and mid-peak Energy Charges adjusted TOU-8 (Below 2kV) - Option R Energy Charge - \$/kWh Summer Season On-Pe Mid-pe Winter Season Mid-pe Off-Pe Customer Charge - \$/month Facilities Related Demand Charge - \$/kW Time Related Demand Charge - \$/kW Summer Season On-Pe Mid-Pe Mid-Pe Winter Season On-Pe Mid-Pe Off-Pe Power Factor Adjustment - \$/kVA TOU-8 (From 2 kV to 50 kV) - Option R Energy Charge - \$/kWh Summer Season	eak eak eak eak eak eak	2011 (100%	phase-in of S	andby Time-F	Related.	0.03174 0.03174 0.03174 0.03174 542.25 5.85	0.31856 0.12672 0.05739 0.07626 0.05431	0.35030 0.15846 0.08913 0.10800 0.08605 542.25 5.85	
Power Factor Adjustment - \$/kVA TOU-8 Summer on- and mid-peak Energy Charges adjusted TOU-8 (Below 2kV) - Option R Energy Charge - \$/kWh Summer Season On-Pe Mid-pe Off-Pe Winter Season Mid-pe Off-Pe Customer Charge - \$/month Facilities Related Demand Charge - \$/kW Time Related Demand Charge - \$/kW Summer Season On-Pe Mid-Pe Winter Season Mid-Pe Off-Pe Power Factor Adjustment - \$/kVA TOU-8 (From 2 kV to 50 kV) - Option R Energy Charge - \$/kWh Summer Season On-Pe	eak eak eak eak eak eak eak	2011 (100%	phase-in of S	andby Time-f	Related.	0.03174 0.03174 0.03174 0.03174 542.25 5.85	0.31856 0.12672 0.05739 0.07626 0.05431	0.35030 0.15846 0.08913 0.10800 0.08605 542.25 5.85	
Power Factor Adjustment - \$/kVA TOU-8 Summer on- and mid-peak Energy Charges adjusted TOU-8 (Below 2kV) - Option R Energy Charge - \$/kWh Summer Season On-Pe Mid-pe Off-Pe Winter Season Mid-pe Off-Pe Customer Charge - \$/month Facilities Related Demand Charge - \$/kW Time Related Demand Charge - \$/kW Summer Season On-Pe Mid-Pe Winter Season Mid-Pe TOU-8 (From 2 kV to 50 kV) - Option R Energy Charge - \$/kWh	eak eak eak eak eak eak eak	2011 (100%	phase-in of S	andby Time-I	Related	0.03174 0.03174 0.03174 0.03174 542.25 5.85	0.31856 0.12672 0.05739 0.07626 0.05431	0.35030 0.15846 0.08913 0.10800 0.08605 542.25 5.85 0.27	
Power Factor Adjustment - \$/kVA TOU-8 Summer on- and mid-peak Energy Charges adjusted TOU-8 (Below 2kV) - Option R Energy Charge - \$/kWh Summer Season On-Pe Mid-pe Off-Pe Customer Charge - \$/month Facilities Related Demand Charge - \$/kW Time Related Demand Charge - \$/kW Summer Season On-Pe Mid-Pe Winter Season On-Pe Off-Pe Tou-8 (From 2 kV to 50 kV) - Option R Energy Charge - \$/kWh Summer Season On-Pe Off-Pe Mid-pe Off-Pe Mid-pe Off-Pe Mid-pe Off-Pe Mid-pe Off-Pe	eak eak eak eak eak eak eak	2011 (100%	phase-in of S	andby Time-l	Related	0.03174 0.03174 0.03174 0.03174 542.25 5.85	0.31856 0.12672 0.05739 0.07626 0.05431	0.35030 0.15846 0.08913 0.10800 0.08605 542.25 5.85	
Power Factor Adjustment - \$/kVA TOU-8 Summer on- and mid-peak Energy Charges adjusted TOU-8 (Below 2kV) - Option R Energy Charge - \$/kWh Summer Season On-Pe Winter Season Mid-pe Off-Pe Customer Charge - \$/month Facilities Related Demand Charge - \$/kW Time Related Demand Charge - \$/kW Summer Season On-Pe Mid-Pe Winter Season Mid-Pe Vinter Season Mid-Pe TOU-8 (From 2 kV to 50 kV) - Option R Energy Charge - \$/kWh Summer Season On-Pe Mid-pe Off-Pe Winter Season	eak eak eak eak eak eak eak	2011 (100%	phase-in of S	andby Time-I	Related	0.03174 0.03174 0.03174 0.03174 542.25 5.85 0.27	0.31856 0.12672 0.05739 0.07626 0.05431 0.05431 0.12632 0.05596	0.35030 0.15846 0.08913 0.10800 0.08605 542.25 5.85 0.27	
Power Factor Adjustment - \$/kVA TOU-8 Summer on- and mid-peak Energy Charges adjusted TOU-8 (Below 2kV) - Option R Energy Charge - \$/kWh Summer Season On-Pe Mid-pe Off-Pe Customer Charge - \$/month Facilities Related Demand Charge - \$/kW Time Related Demand Charge - \$/kW Summer Season On-Pe Mid-Pe Winter Season On-Pe Off-Pe Tou-8 (From 2 kV to 50 kV) - Option R Energy Charge - \$/kWh Summer Season On-Pe Off-Pe Mid-pe Off-Pe Mid-pe Off-Pe Mid-pe Off-Pe Mid-pe Off-Pe	eak eak eak eak eak eak eak	2011 (100%	phase-in of S	andby Time-F	Related	0.03174 0.03174 0.03174 0.03174 542.25 5.85	0.31856 0.12672 0.05739 0.07626 0.05431	0.35030 0.15846 0.08913 0.10800 0.08605 542.25 5.85 0.27	

	Effec	Rates tive December	er 2008	Se	ettlement Rat	es	
Note: End of year 2009 revenue requirement as specified in Paragraph 5.b.ii of Phase 2 Revenue Allocation Settlement Agreement. Customer Charge - \$/month	Delivery	Generation	Total Rate	Delivery 291.00	Generation	Total Rate 291.00	Total Rate Change
Facilities Related Demand Charge - \$/kW Time Related Demand Charge - \$/kW Summer Season On-Peak Mid-Peak				5.48		5.48	
Winter Season Mid-Peak Off-Peak							
Power Factor Adjustment - \$/kVA				0.27		0.27	
TOU-8 (Above 50 kV) - Option R Energy Charge - S/kWh							
Summer Season							
On-Peak				0.01692	0.27391	0.29083	
Mid-peak				0.01692	0.10542	0.12234	
Off-Peak				0.01692	0.04695	0.06387	
Winter Season							
Mid-peak Off-Peak				0.01692 0.01692		0.08257 0.06354	
Customer Charge - \$/month Facilities Related				2232.25		2232.25	
Demand Charge - \$/kW Time Related Demand Charge - \$/kW				3.48		3.48	
Summer Season On-Peak Mid-Peak							
Winter Season Mid-Peak Off-Peak							
Power Factor Adjustment - \$/kVA				0.32		0.32	

ATTACHMENT E

Agriculture and Pumping Rate Group Rate Design Settlement Agreement

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Southern California Edison)	
Company (U 338-E) To Establish Marginal)	Application 08-03-002
Costs, Allocate Revenues, And Design Rates)	(Filed March 4, 2008)
)	
In the Matter of the Application of Southern)	
California Edison Company (U 338-E) for)	Application 07-12-020
Authority to Make Various Electric Rate Design)	(Filed December 21, 2007)
Changes.)	

PHASE 2 AGRICULTURE AND PUMPING RATE GROUP RATE DESIGN
SETTLEMENT AGREEMENT

Dated: February 4, 2009

AGRICULTURE AND PUMPING RATE GROUP RATE DESIGN SETTLEMENT AGREEMENT

Para	igrapn 1	itle	Page
1.	Parties		1
2.	Recitals		1
3.	Definitions		2
4.	Agreement		5
5.	Implementation of Agreement		13
6.	Incorporation of Complete Agreement.		13
7.	Signature Date		13
8.	Regulatory Approval		13
9.	Compromise Of Disputed Claims		13
10.	Non Precedent		14
11.	Previous Communications		14
12.	Non Waiver		14
13.	Effect Of Subject Headings		14
14.	Governing Law		14
15.	Number Of Originals		15
APPENDIX	A AGRICULTURE AND PUM	IPING RATE GROUPS ILLUSTE	RATIVE RATES

PHASE 2 AGRICULTURE AND PUMPING RATE GROUP RATE DESIGN SETTLEMENT AGREEMENT

This Phase 2 Agriculture And Pumping Rate Group Rate Design 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),
California Farm Bureau Federation (CFBF), and Agricultural Energy Consumers Association
(AECA), (referred to hereinafter collectively as Parties or Settling Parties or individually as
Party).

- 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.
- b. CFBF is a voluntary, private, non-profit corporation representing more than 85,000 members and over 80 percent of California's commercial agriculture.
- c. 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.

2. Recitals

a. In Phase 2 of SCE's 2009 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 March 4, 2008, SCE served its initial prepared testimony regarding marginal costs, revenue allocation and rate design in Application 08-03-002.
 SCE updated its initial showing on June 27, 2008.
- c. In accordance with the Scoping Memo and Ruling of the Assigned Commissioner, dated May 14, 2008, 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 12, 2008.
- d. DRA served its initial testimony on September 26, 2008. Interveners, including the Settling Parties, served their initial testimony on October 31, 2008.
- e. Continuing settlement discussions occurred among the interested parties after November 12, 2008.
- f. The Parties have evaluated the impacts of the various proposals in this consolidated proceeding for A.08-03-002 and A.07-12-020 and desire to resolve all issues related to rate design for the Agriculture and Pumping rate group as indicated in Paragraph 4 of this Agreement.

3. Definitions

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

a. "Account Aggregation" refers to virtual aggregation of a single customer's multiple service accounts for generation billing purposes. Under this method of aggregation, each of the aggregated accounts is separately metered; however, the generation time-related billing demands would be aggregated at the billing system level to reflect some level of diversity. All other billing determinants are treated consistent with separately-metered accounts.

- b. "Agreement" shall have the meaning given to such term in the introductory paragraph hereof.
- c. "Agriculture and Pumping Rate Groups" refers to customers with demands less than 500 kW who receive service on the following SCE rate schedules: PA-1, PA-2, TOU-PA, TOU-PA-5, TOU-PA-SOP, and PA-RTP.
- d. "BIP", "API-BIP", or Base Interruptible Program means a rate schedule applicable to time-of-use agriculture and pumping customers who receive a credit applied to their summer and winter Time-Related Demand Charges in return for the customer's agreement to reduce its demand to a specified level within either 15 or 30 minutes of notification by SCE of the need to reduce load.
- e. "Commission" or "CPUC" means the California Public Utilities Commission.
- f. "Critical Peak Pricing" or CPP means a dynamic rate that allows a short-term price increase to a predetermined level to reflect real-time system conditions. Typically, the time and duration of the price increase are predetermined, but the event days are not predetermined.
- g. "Customer Charges" mean the dollar per month charges applicable to certain Agriculture and Pumping Rate Group rate schedules.
- h. "Demand Charges" mean those charges that are comprised of Facilities-Related Demand Charges and Time-Related Demand Charges, which are based on the customer's maximum kW demand during the billing period. Demand Charges recover a portion of SCE's delivery and generation costs.
- i. "Energy Charges" mean the dollar per kilowatt-hour (kWh) charges applicable to rate schedules in the Agriculture and Pumping rate group.

Energy Charges recover a portion of SCE's costs for delivery service and generation. For TOU rate schedules, utility retained generation Energy Charges are set residually such that the weighted average of URG and DWR Energy Charges provides a TOU price signal consistent with marginal cost differentials.

- j. "EPMC" means equal percent of marginal cost. Because marginal cost revenues do not equal the utility's revenue requirement, in general, the utility revenue requirement is allocated to different rate groups in proportion to each rate group's percentage share of marginal cost revenue responsibility by function (*i.e.* separately for generation versus distribution, and customer).
- k. "Facilities-Related Demand Charges" are charges applied to customers' monthly peak demands not differentiated by TOU or by season that are designed to recover certain transmission and distribution costs that are defined to be unrelated to generation system peak or coincident peak usage.
- 1. "Functional SAPC Allocation" means allocation of SCE's revenue requirement to each of SCE's rate groups based on the system average percentage change for the particular function, *e.g.*, distribution or generation.
- m. "Settling Parties" means SCE, CFBF, and AECA.
- n. "Time-Related Demand Charges" are generation-related, marginal cost based, capacity-related charges assigned to TOU periods based on loss-of-load probabilities or loss of load expectations during the TOU periods. Scaled TOU marginal energy costs along with the Time-Related Demand Charges are designed to collect the allocated revenue requirement for SCE's base generation and fuel and purchased power costs.

4. Agreement

In consideration of the mutual obligations, covenants and conditions contained herein, the Settling Parties agree to the terms of this Agreement. Nothing in this Paragraph 4 of this Agreement shall be deemed to constitute an admission or an acceptance by any Party of any fact, principle, or position contained herein. This Agreement is subject to the express limitation on precedent described in Paragraph 10. The Parties, by signing this Agreement, acknowledge that they pledge support for Commission approval and subsequent implementation of all the provisions of the Agreement.

a. Common Pricing Principles

1. Rate Structure

The current rate structure, consisting of Customer Charges, Energy Charges, and Demand Charges shall be maintained for all applicable rate schedules, with the exception of Schedule PA-2 which will now include a summer Time-Related Demand Charge.

2. Customer Charges

Effective October 1, 2009, Customer Charges shall be increased by a maximum of 20 percent above current levels, but in no case shall the charges exceed the full EPMC level of Customer Charge based on SCE's RECC method. Any revenue deficiencies caused by the capping will be recovered in distribution energy charges.

3. Demand Charges

Demand Charges shall be differentiated by season. However, the seasonality, and in some cases time differentiation, shall be retained in the design of Time-Related Demand Charges only, with no seasonal or TOU differences in the Facilities-Related Demand Charges.

4. Non-Generation Related Energy Charges

Energy Charges that are designed to recover revenues associated with transmission, distribution, public purpose programs, nuclear decommissioning, CARE balancing account, PUCRF and the California Department of Water Resources bonds shall be established on the basis of the specific functional authorized revenue requirements and the terms specified in the 2009 GRC Phase 2 Revenue Allocation Agreement, which was filed January 9, 2009.

5. Demand Response Credits

Rate structures and rate designs associated with SCE's demand response programs, *e.g.*, AP-I, API-BIP, and CPP shall be as proposed by SCE in Exhibit SCE-04 (Updated), dated June 27, 2008.

6. Implementing Revenue Changes in Rates

Changes to Energy Charges and Demand Charges shall be implemented on a Functional SAPC allocation basis whenever changes to SCE's authorized distribution and generation revenue requirements are implemented.

7. Illustrative Rates

Rates for the Agriculture and Pumping Rate Group shall be designed consistent with Appendix A.

b. Agriculture and Pumping Rate Groups

1. Schedules PA-1 and PA-2

Customers with peak demands up to 199 kW shall take service on a default basis on an applicable non-TOU rate schedule (Schedule PA-1 or PA-2). Customers shall also have the option of taking service on an applicable TOU rate schedule, *e.g.* Schedule TOU-

PA. For Schedule PA-1, the default rate structure shall consist of a monthly Customer Charge, a Service Charge, and Energy Charge. For Schedule PA-2, the default rate structure shall consist of a monthly Customer Charge, a seasonal Time-Related Demand Charge, a Facilities-Related Demand Charge, and seasonal Energy Charges. Customers served on rate schedules in these rate groups shall have the option, unless they are otherwise ineligible, to participate on the CPP tariff.

2. TOU-PA and TOU-PA-5 Rate Groups

Schedule TOU-PA (Rate B) is the default rate schedule with Schedules TOU-PA (Rate A) and TOU-PA-5 as optional rate schedules for agriculture and pumping customers with demands greater than 200 kW. The default rate structure shall consist of a monthly Customer Charge, seasonal Time-Related Demand Charges, a Facilities-Related Demand Charge, and seasonal Energy Charges. Customers served on rate schedules in these rate groups shall have the option, unless they are otherwise ineligible, to participate on the CPP tariff.

3. Schedule TOU-PA-SOP and PA-RTP Options

The optional super off-peak (SOP) and real-time pricing (RTP) schedules shall remain available for customers who meet the applicability criteria. Schedule TOU-PA-SOP shall retain its existing rate and TOU period structure. The total SOP energy rate will be set initially at current levels; however, the rate will be adjusted based on the specific functional authorized revenue requirements and the terms specified in the 2009 GRC Phase 2 Revenue Allocation Settlement Agreement. Schedule PA-RTP will remain open to new customers and will be designed to be revenue neutral to Schedule TOU-PA (Rate B). The real-time energy prices for PA-RTP shall be established using the same

methodology as used for RTP-2 described in Exhibit SCE-04 (Updated), dated June 27, 2008 consistent with the following: Schedule PA-RTP generation capacity charges shall reflect a generation marginal capacity cost of \$114.10 per kW per year. Schedule PA-RTP Energy Charges shall reflect a generation marginal energy cost based on a natural gas burnertip price of \$7.00 per million BTUs. Delivery service rates for Schedule PA-RTP shall be the same as the delivery service rates for Schedule TOU-PA (Rate B). The applicability for Schedule PA-RTP shall be modified to be consistent with Schedule TOU-PA (Rate B).

4. Schedule TOU-PA-7

Schedule TOU-PA-7 shall be eliminated. Customers currently served on this schedule will be transferred to their otherwise applicable tariff, or any available optional tariff of their choosing.

c. Customer Charges

Effective October 1, 2009, estimated monthly Customer Charges shall be as follows:

Agriculture and Pumping Rate Groups Estimated Customer Charges (\$/mo.)

Rate Schedule	Customer
	Charge
PA-1	36.02
PA-2	70.69
TOU-PA	100.48
TOU-PA-5	102.07
TOU-PA-SOP	100.48

d. Time-Related Demand Charges

Time-Related Demand Charges shall be established consistent with the values for generation marginal energy and capacity costs, relative loss-of-load expectation and the estimated adjusted consolidated revenue requirement set forth in the Phase 2 Revenue Allocation Settlement Agreement.

The Time-Related Demand Charges for Schedules TOU-PA (Rate B) and TOU-PA-5 shall be established in the same manner as for TOU-GS-3 and TOU-8-Sec rate groups, *i.e.* with an assumed generation marginal capacity cost of \$95 per kW per year, instead of the \$114.10 per kW per year that underlies the Phase 2 Revenue Allocation Settlement Agreement. The generation revenue deficiency caused by this adjusted generation marginal capacity cost shall be recovered solely in the summer season on-peak and mid-peak Energy Charges for Schedule TOU-PA (Rate B) and Schedule TOU-PA-5,

The Schedule PA-2 summer season Time-Related Demand Charge shall be capped at \$3.50 per kW. The generation revenue deficiency caused by this cap shall be recovered solely in the summer season Energy Charge for the PA-2 rate group.

Agriculture and Pumping Rate Group Estimated Time-Related Demand Charges (\$/kW)

	TOU-PA Rate B	TOU-PA-5	TOU-PA-SOP
Summer On- Peak	11.22	15.01	25.75
Summer Mid- Peak	2.68	4.21	0.0

On October 1, 2009, these estimated Time-Related Demand Charges shall be adjusted as necessary consistent with the Phase 2 Revenue Allocation Settlement Agreement. These estimated Time-Related Demand Charges shall be adjusted by the appropriate SAPC generation scalar when SCE's authorized revenues change after October 1, 2009.

e. Facilities-Related Demand Charges

Estimated Facilities-Related Demand Charges (set to recover certain allocated delivery revenues, including SCE's adopted transmission

revenues) for the Agriculture and Pumping rate groups shall be established consistent with SCE's proposed marginal costs (Exhibit SCE-02 (Updated) and rate design (Exhibit SCE-04 (Updated)) as follows:

Agriculture and Pumping Rate Group Estimated Facilities-Related Demand Charges (\$/kW)

PA-2	TOU-PA	TOU-PA-5	TOU-PA-SOP
7.71	7.22	10.23	7.22

On October 1, 2009, these estimated Facilities-Related Demand Charges shall be adjusted as necessary consistent with the Phase 2 Revenue Allocation Settlement Agreement. These estimated Facilities-Related Demand Charges shall be adjusted, as necessary, by the appropriate SAPC distribution scalar when SCE's authorized revenues change after October 1, 2009 and consistent with then-current FERC-authorized transmission revenues.

f. Energy Charges

Generation-related Energy Charges shall be established based on marginal energy costs by TOU periods set forth in the Phase 2 Revenue Allocation Settlement Agreement in order to recover, in conjunction with the Time-Related Demand Charges, SCE's generation revenues allocated to each Agriculture and Pumping Rate Group. As described in paragraph 4.d., above, any revenue deficiency resulting from the capped SCE generation capacity charges reflected in the TOU-PA (Rate B), TOU-PA-5, and PA-2 rate schedules will be recovered through the respective TOU or seasonal energy charges for these rate schedules. For Schedule TOU-PA (Rate A), the total summer on-peak energy rate shall be capped initially at 20 cents per kWh, and the resulting revenue deficiency will be recovered through the winter mid-peak energy charge. For PA-SOP, the winter and summer total super off peak energy rates shall be set initially at current levels. The

resulting summer revenue deficiency will be recovered through the applicable summer on-peak energy rate, and the resulting winter revenue deficiency will be recovered through the winter mid-peak energy rate.

g. CPP Program Design and Revenue Treatment

1. CPP Design

CPP will be optional for the Agriculture and Pumping rate group. SCE's CPP tariff shall allow no more than 15 events per year, nor less than 9 events per year, but is designed to be activated for 12 events per year on non-holiday summer weekdays and may occur only during the time period from 2:00 p.m. to 6:00 p.m.

2. CPP Bill Protection

A customer who is subject to the CPP tariff (regardless of demand level) shall be provided bill protection such that bills under CPP for the first 12 months shall not exceed bills calculated on the customer's otherwise applicable tariff provided the customer remains on the CPP tariff for a full year. Customers who do not remain on the CPP tariff for a full year shall forfeit any bill protection credits.

3. CPP Revenue Allocation

An undercollection of revenues relative to the design of the CPP rate will occur when fewer than the number of design events are called, and an overcollection will occur when the number of called events is greater than the number of designed events. The revenue imbalances resulting in the ERRA balancing account from this variation shall be retained in the rate group that is responsible for the amount of the revenue imbalance.

h. Schedule PA-2 Customers

As described in sections 4.a.2. and 4.d., above, the rate structure for

Schedule PA-2 will be modified to include a summer season demand charge. The Settling Parties agree that customers who are potentially impacted should be made aware of this change. Accordingly, by the end of calendar year 2009, SCE will perform a one-time review of PA-2 customers' annual bills. Where bill comparisons indicate that customers may achieve significant annual percentage bill savings on Schedule PA-1, *e.g.*, three percent or more, SCE will notify such customers and offer them the opportunity to change to Schedule PA-1.

i. TOU-PA Customers

By the end of calendar year 2009, SCE will perform a one-time review of TOU-PA-B, TOU-PA-5 and TOU-PA-SOP customers' annual bills. Where bill comparisons indicate that customers may achieve significant annual percentage bill savings on other rate schedules, *e.g.*, three percent or more, SCE will notify such customers and offer them the opportunity to change to the alternative rate schedule.

j. Customer Account Aggregation

Aggregation of customer accounts, as proposed by AECA in this proceeding, will not be permitted. In lieu of Account Aggregation, SCE will offer customers an hourly pricing schedule similar to the current PARTP schedule. In addition, SCE agrees to work with AECA and other interested parties to identify energy cost management tools and technologies for agricultural customers.

k. Review of Revenue Allocation and Rate Design Issues

SCE agrees to meet with representatives of AECA and CFBF to review the issues on revenue allocation and rate design raised by each party in its prepared testimony. The intention of this meeting is to (1) resolve factual and analytical issues where possible and (2) discuss potential joint studies that might assist in resolving issues prior to SCE's filing of its next general rate case application.

5. <u>Implementation of Agreement</u>

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 but no earlier than October 1, 2009.

6. 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 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.

7. Signature Date

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

8. 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.

9. 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.

Non Precedent

Consistent with Rule 12.5 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 or unless the Commission expressly provides otherwise.

11. 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.

12. 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.

13. Effect Of Subject Headings

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

14. 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.

15. 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.

SOUTHERN CALIFORNIA EDISON COMPANY

By: /s/ Bruce Reed

Title: Senior Attorney Date: 2/5/2009

CALIFORNIA FARM BUREAU FEDERATION

By: /s/ Ron Liebert

Title: Associate Counsel Date: 2/5/2009

AGRICULTURAL ENERGY USERS ASSOCIATION

By: /s/ Dan Geis

Title: Assistant Executive Director Date: 2/5/2009



Agriculture and Pumping Rate Groups Illustrative Rates

			Rates	1	Γ			1	
		Effect	ive Decembe	r 2008		Settlement Rates			
in Paragr	nd of year 2009 revenue requirement as specified aph 5.b.ii of Phase 2 Revenue Allocation nt Agreement.	Delivery	Generation	Total Rate		Delivery	Generation	Total Rate	Total Rate Change
						-			
PA-1	Energy Charge - \$/kWh	0.02559	0.10973	0.13532		0.04313	0.11012	0.15325	13.25%
	Customer Charge - \$/month	30.02	0.00	30.02		36.02	0.00	36.02	19.99%
	Service Charge - \$/hp	2.23	0.00	2.23		2.05	0.00	2.05	-7.85%
	Off Peak Credit - \$/hp	(2.01)	0.00	(2.01)		0.00	(2.03)	(2.03)	-1.00%
	Voltage Discount, Energy - \$/kWh								
	From 2 kV to 50 kV above 50 kV	0.00000 0.00000	(0.00199) (0.00433)	(0.00199) (0.00433)		0.00000 0.00000	(0.00210) (0.00468)	(0.00210) (0.00468)	-5.59% -8.05%
	Voltage Discount, Connected Load - \$/Hp From 2 kV to 50 kV	(0.14)	0.00	(0.14)		(0.03)	0.00	(0.03)	78.57%
	above 50 kV	(4.66)	0.00	(4.66)		(0.95)	0.00	(0.95)	79.61%
PA-2	Energy Charge - \$/kWh								
	Summer Winter	0.01551 0.01551	0.07351 0.07171	0.08902 0.08722		0.01886 0.01886	0.11196 0.06671	0.13082 0.08557	46.96% -1.89%
	Customer Charge - \$/month Facilities Related	58.91	0.00	58.91		70.69	0.00	70.69	20.00%
	Demand Charge - \$/kW Time Related Demand Charge - \$/kW	8.83	0.00	8.83		7.71	0.00	7.71	-12.64%
	Summer Season Winter Season	0.00 0.00	0.00 0.00	0.00 0.00		0.00	3.50 0.00	3.50 0.00	
	TOU Option Meter Charge - \$/month								
	Standard	18.43	0.00	18.43		21.23	0.00	21.23	15.19%
	TOU-RTEM Voltage Discount, Facilities Related Demand - \$/kW	158.83	0.00	158.83		88.48	0.00	88.48	-44.29%
	From 2 kV to 50 kV	(0.19)	0.00	(0.19)		(0.09)	0.00	(0.09)	52.63%
	above 50 kV	(6.25)	0.00	(6.25)		(2.98)	0.00	(2.98)	52.32%
	Voltage Discount, Time-Related Demand - \$/kW								
	From 2 kV to 50 kV	0.00	0.00	0.00		0.00	(0.35)	(0.35)	
	above 50 kV Voltage Discount, Energy - \$/kWh	0.00	0.00	0.00		0.00	(0.96)	(0.96)	
	From 2 kV to 50 kV	0.00000	(0.00199)	(0.00199)		0.00000	(0.00140)	(0.00140)	29.61%
	above 50 kV	0.00000	(0.00433)	(0.00433)		0.00000	(0.00312)	(0.00312)	27.97%
PA-RTP									
	Energy Charge - \$/kWh	0.01356		Variable*		0.01662	Variable*	Variable*	
	Customer Charge - \$/month Facilities Related	83.73	0.00	83.73		100.48	0.00	100.48	20.00%
	Demand Charge - \$/kW Voltage Discount, Hourly Rates - %	4.46	0.00	4.46		7.22	0.00	7.22	61.82%
	From 2 kV to 50 kV above 50 kV	0.00% 0.00%				0.00% 0.00%	-2.39% -5.32%	-2.39% -5.32%	
	Power Factor Adjustment - \$/kVA								
	Greater than 50 kV 50 kV or less	0.20 0.18	0.00 0.00	0.20 0.18		0.32 0.27	0.00 0.00	0.32 0.27	60.00% 50.00%

^{*}See RTP Schedules for PA-RTP.

	Detec					l		
	Rates							
	Effect	ive Decembe	r 2008		Settlement Rates		es	ļ
Note: End of year 2009 revenue requirement as specified								
in Paragraph 5.b.ii of Phase 2 Revenue Allocation								Total Rate
Settlement Agreement.	Delivery	Generation	Total Rate		Delivery	Generation	Total Rate	Change
TOU-PA (Rate A)	Delivery	Generation	Total Nate		Delivery	Generation	Total Nate	Onlinge
Energy Charge - \$/kWh								
Summer Season								
On-Peak	0.01356	0.10204	0.11560		0.01662	0.18338	0.20000	73.01%
Mid-peak	0.01356	0.08615	0.09971		0.01662	0.09155	0.10817	8.49%
Off-Peak	0.01356	0.03509	0.03371		0.01662	0.03133	0.06431	32.19%
Winter Season	0.01330	0.03303	0.04003		0.01002	0.04703	0.00431	32.1370
Mid-peak	0.01356	0.09745	0.11101		0.01662	0.08467	0.10129	-8.75%
Off-Peak	0.01356	0.03509	0.04865		0.01662	0.04611	0.06273	28.95%
OII-F eak	0.01330	0.03309	0.04803		0.01002	0.04011	0.00273	20.9370
Customer Charge - \$/month	83.73	0.00	83.73		100.48	0.00	100.48	20.00%
Service Charge - \$/hp	3.75	1.03	4.78		5.41	0.00	5.41	13.21%
Voltage Discount, Energy - \$/kWh	3.73	1.03	4.10		3.41	0.00	J. 4 I	13.21/0
From 2 kV to 50 kV	0.00000	(0.00199)	(0.00199)		0.00000	(0.00132)	(0.00132)	33.62%
above 50 kV	0.00000	(0.00199)	(0.00199)		0.00000	(0.00132)	(0.00132)	31.92%
Voltage Discount, Connected Load - \$/Hp	0.00000	(0.00432)	(0.00432)		0.00000	(0.00254)	(0.00234)	31.3270
From 2 kV to 50 kV	(0.14)	0.00	(0.14)		(0.07)	0.00	(0.07)	50.00%
above 50 kV	(4.68)	0.00	(4.68)		(2.28)	0.00	(2.28)	51.28%
above 30 kV	(4.00)	0.00	(4.00)		(2.20)	0.00	(2.20)	31.2070
TOU-PA (Rate B)								
Energy Charge - \$/kWh								
Summer Season								
On-Peak	0.01356	0.09989	0.11345		0.01662	0.10324	0.11986	5.65%
Mid-peak	0.01356	0.08224	0.09580		0.01662	0.06729	0.08391	-12.41%
Off-Peak	0.01356	0.03510	0.04866		0.01662	0.04770	0.06432	32.19%
Winter Season	0.01000	0.00010	0.04000		0.01002	0.04770	0.00402	02.1070
Mid-peak	0.01356	0.09320	0.10676		0.01662	0.06686	0.08348	-21.80%
Off-Peak	0.01356	0.03510	0.04866		0.01662	0.04613	0.06275	28.96%
on roun	0.01000	0.00010	0.01000		0.01002	0.0.10.10	0.002.0	20.0070
Customer Charge - \$/month Facilities Related	83.73	0.00	83.73		100.48	0.00	100.48	20.00%
Demand Charge - \$/kW	5.01	0.00	5.01		7.22	0.00	7.22	44.05%
Time Related Demand Charge - \$/kW	2.0.	2.30	2.0.			2.30		2070
Summer Season								
On-Peak	0.00	9.77	9.77		0.00	11.22	11.22	14.84%
Mid-Peak	0.00	0.00	0.00		0.00	2.68	2.68	
Voltage Discount, Facilities Related Demand - \$/kW								
From 2 kV to 50 kV	(0.19)	0.00	(0.19)		(0.10)	0.00	(0.10)	47.37%
above 50 kV	(6.25)	0.00	(6.25)		(3.04)	0.00	(3.04)	51.36%
Voltage Discount, Time-Related Demand - \$/kW								
From 2 kV to 50 kV	0.00	(0.39)	(0.39)		0.00	(0.19)	(0.19)	51.28%
above 50 kV	0.00	(1.04)	(1.04)		0.00	(0.54)	(0.54)	48.08%
Voltage Discount, Energy - \$/kWh								
From 2 kV to 50 kV	0.00000	(0.00199)	(0.00199)		0.00000	(0.00132)	(0.00132)	33.62%
above 50 kV	0.00000	(0.00432)	(0.00432)		0.00000	(0.00294)	(0.00294)	31.92%
		,					,	
TOU-PA (Both Options)								
Power Factor Adjustment - \$/kVA								
Greater than 50 kV	0.20	0.00	0.20		0.32	0.00	0.32	60.00%
50 kV or less	0.18	0.00	0.18		0.27	0.00	0.27	50.00%

		Rates]		
		Effec	tive December	2008		Settlement Rates			
					İ				
Noto: En	d of year 2000 revenue requirement as specified								
	d of year 2009 revenue requirement as specified aph 5.b.ii of Phase 2 Revenue Allocation								Total Rate
-	t Agreement.	Delivery	Generation	Total Rate		Delivery	Generation	Total Rate	Change
TOU-PA-5					•				
	Energy Charge - \$/kWh								
	Summer Season	0.04000	0.00040	0.00000		0.04044	0.00054	0.44505	44.700/
	On-Peak Mid-peak	0.01362 0.01362	0.06646 0.05368	0.08008 0.06730		0.01641 0.01641	0.09954 0.06785	0.11595 0.08426	44.79% 25.20%
	Off-Peak	0.01362	0.03300	0.04535		0.01641	0.04398	0.06039	33.16%
	Winter Season								
	Mid-peak	0.01362	0.05666	0.07028		0.01641	0.05912	0.07553	7.47%
	Off-Peak	0.01362	0.03352	0.04714		0.01641	0.04171	0.05812	23.29%
	0	05.00	0.00	05.00		400.07	0.00	400.07	20.00%
	Customer Charge - \$/month Minimum Charge - \$/kW	85.06	0.00	85.06		102.07	0.00	102.07	20.00%
	Summer Season	9.94	29.46	39.40		10.69	29.46	40.15	1.90%
	Winter Season	8.42	11.99	20.41		9.19	11.99	21.18	3.75%
	Facilities Related								
	Demand Charge - \$/kW	9.95	0.00	9.95		10.23	0.00	10.23	2.80%
	Time Related Demand Charge - \$/kW								
	Summer Season On-Peak	0.00	10.49	40.40		0.00	45.04	45.04	43.09%
	On-Peak Mid-Peak	0.00	0.00	10.49 0.00		0.00	15.01 4.21	15.01 4.21	43.09%
	Mid-i eak	0.00	0.00	0.00		0.00	7.21	7.21	
	Winter Season								
	Mid-Peak	0.00				0.00	0.00	0.00	
	Off-Peak	0.00				0.00	0.00	0.00	
	Description A.E. stored Child								
	Power Factor Adjustment - \$/kVA Greater than 50 kV	0.20	0.00	0.20		0.32	0.00	0.32	60.00%
	50 kV or less	0.20	0.00	0.20		0.32	0.00	0.32	50.00%
	50 KV 51 1555	0.10	0.00	0.10		0.2.	0.00	0.2.	00.0070
	Voltage Discount, Facilities Related Demand - \$/kW								
	From 2 kV to 50 kV	(0.19)	0.00	(0.19)		(0.14)		(0.14)	26.32%
	above 50 kV	(6.24)	0.00	(6.24)		(4.50)	0.00	(4.50)	27.88%
	Voltage Discount, Time-Related Demand - \$/kW From 2 kV to 50 kV	0.00	(0.39)	(0.39)		0.00	(0.31)	(0.31)	20.51%
	above 50 kV	0.00	(1.04)	(0.39)		0.00	(0.86)	(0.86)	17.31%
	Voltage Discount, Energy - \$/kWh	0.00	(1.04)	(1.04)		0.00	(0.00)	(0.00)	17.0170
	From 2 kV to 50 kV	0.00000	(0.00199)	(0.00199)		0	(0.00134)	(0.00134)	32.54%
	above 50 kV	0.00000	(0.00432)	(0.00432)		0	(0.00299)	(0.00299)	30.81%
	_								
TOU-PA-IC									
	Energy Charge - \$/kWh Summer Season								
	On-Peak	0.01885	0.13670	0.15555		0.02207	0.13581	0.15788	1.50%
	Mid-peak	0.01885	0.07425	0.09310		0.02207	0.07242	0.09449	1.49%
	Off-Peak	0.01885	0.02293	0.04178		0.02207	0.02033	0.04240	1.48%
	Winter Season								
	Mid-peak Off-Peak	0.01885	0.09385	0.11270		0.02207	0.09231	0.11438	1.49%
	Utt-Peak	0.01885	0.02293	0.04178		0.02207	0.02033	0.04240	1.48%
	Customer Charge - \$/month	50.14	0.00	50.14		50.89	0.00	50.89	1.50%
	Facilities Related	30.14	3.00	50.1-T		50.00	5.00	20.00	1.0070
	Demand Charge - \$/kW	3.02	0.00	3.02		3.07	0.00	3.07	1.66%
	Time Related Demand Charge - \$/kW								
	Summer Season								
	On-Peak	1.09	0.05	1.14 0.00		1.09	0.07	1.16	1.75%
	Mid-Peak	0.00	0.00	0.00		0.00	0.00	0.00	
	Voltage Discount, Facilities Related Demand - \$/kW								
	From 2 kV to 50 kV	(0.10)	0.00	(0.10)		(0.10)	0.00	(0.10)	0.00%
	above 50 kV	(2.39)	0.00	(2.39)		(2.39)	0.00	(2.39)	0.00%
	Voltage Discount, Time-Related Demand - \$/kW								
	From 2 kV to 50 kV	(0.18)	0.00	(0.18)		(0.18)		(0.18)	
	above 50 kV Voltage Discount, Energy - \$/kWh	(1.09)	0.00	(1.09)		(1.09)	0.00	(1.09)	0.00%
	From 2 kV to 50 kV	0.00000	(0.00049)	(0.00049)		0.00000	(0.00068)	(0.00068)	-38.78%
	above 50 kV	0.00000	(0.00105)	(0.00105)		0.00000	(0.00145)	(0.00145)	-38.10%
			. ,	,			. ,	. ,	
	Power Factor Adjustment - \$/kVA								
	Greater than 50 kV	0.20	0.00	0.20		0.00	0.00	0.00	-100.00%
	50 kV or less	0.18	0.00	0.18		0.00	0.00	0.00	-100.00%

	Rates						
	Effec	tive Decembe	r 2008	Settlement Rates			
Note: End of year 2009 revenue requirement as specified							
in Paragraph 5.b.ii of Phase 2 Revenue Allocation							Total Rate
Settlement Agreement.	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Change
TOU-PA-SOP							
Energy Charge - \$/kWh							
Summer Season							
On-Peak	0.01356	0.08150	0.09506	0.01662	0.09592	0.11254	18.39%
Off-peak	0.01356	0.05672	0.07028	0.01662	0.05786	0.07448	5.98%
Super Off-Peak Winter Season	0.01356	0.03404	0.04760	0.01662	0.03098	0.04760	0.01%
Off-peak	0.01356	0.05689	0.07045	0.01662	0.06748	0.08410	19.38%
Super Off-Peak	0.01356	0.03368	0.04724	0.01662	0.03061	0.04723	-0.02%
Customer Charge - \$/month Facilities Related	83.73	0.00	83.73	100.48	0.00	100.48	20.00%
Demand Charge - \$/kW	5.01	0.00	5.01	7.22	0.00	7.22	44.05%
Time Related Demand Charge - \$/kW Summer Season							
On-Peak	0.00	18.56	18.56	0.00	25.75	25.75	38.74%
Off-Peak	0.00	0.00	0.00	0.00	0.00	0.00	
Winter Season Off-Peak	0.00			0.00	0.00	0.00	
Super Off-Peak	0.00			0.00	0.00	0.00	
Other Charges							
Power Factor Adjustment - \$/kVA							
Greater than 50 kV	0.20	0.00	0.20	0.32	0.00	0.32	60.00%
50 kV or less Voltage Discount, Facilities Related Demand - \$/kW	0.18	0.00	0.18	0.27	0.00	0.27	50.00%
From 2 kV to 50 kV	(0.19)	0.00	(0.19)	(0.10)	0.00	(0.10)	47.37%
above 50 kV	(6.25)	0.00	(6.25)	(3.04)	0.00	(3.04)	51.36%
Voltage Discount, Time-Related Demand - \$/kW							
From 2 kV to 50 kV	0.00	(0.39)	(0.39)	0.00	(0.19)	(0.19)	51.28%
above 50 kV Voltage Discount, Energy - \$/kWh	0.00	(1.04)	(1.04)	0.00	(0.54)	(0.54)	48.08%
From 2 kV to 50 kV	0.00000	(0.00199)	(0.00199)	0.00000	(0.00132)	(0.00132)	33.62%
above 50 kV	0.00000	(0.00432)	(0.00432)	0.00000	(0.00294)	(0.00294)	31.92%
AP-I							
Interruptible Credit \$/kWh	(0.00933)	0.00000	(0.00933)	(0.01164)	0.00000	(0.01164)	-24.76%
\$,	(0.00000)	0.00000	(0.00000)	(0.01.01)	0.00000	(0.01101)	2070
Excess Energy Charge - \$/kWh				12.21107	0.00000	12.21107	
Below 2 kV	10.21374	0.00000	10.21374	0.53693	0.00000	0.53693	-94.74%
F rom 2 kV to 50 kV a bove 50 kV	9.99551 9.63234	0.00000	9.99551 9.63234	0.53693 0.53693	0.00000	0.53693 0.53693	-94.63% -94.43%
above 30 KV	5.05254	0.0000	0.00204	0.00083	0.00000	v.00000	-04.40/0
AGTOU-BIP							
BIP Option Credit (\$/KW)							
Summer On Peak Summer Mid - Peak				(17.22)	0.00 0.00	(17.22)	
Winter Mid - Peak Winter Mid - Peak				(3.66) (1.25)	0.00	(3.66) (1.25)	
William I dan				(1.20)	0.00	(1.20)	
Excess Energy Charge - \$/kWh				12.21107	0.00000	12.21107	

	Rates Effective December 2008			Settlement Rates			es	
		1	2000	İ				
Note: End of year 2009 revenue requirement as specified in Paragraph 5.b.ii of Phase 2 Revenue Allocation Settlement Agreement. Optional CPP rider < 200 kW	Delivery	Generation	Total Rate		Delivery	Generation	Total Rate	Total Rate Change
CPP Event Energy Charge - \$/kWh								
PA-1					0.00000	1.36229	1.36229	
PA-2					0.00000	1.36229	1.36229	
AG-TOU					0.00000	1.36229	1.36229	
TOU-PA-5					0.00000	1.36229	1.36229	
Summer Non-Event Energy Credit - \$/kWh								
PA-1					0.00000	-0.02752	-0.02752	
Summer Non-Event Demand Credit - \$/kWh								
PA-2					0.00	(7.44)	(7.44)	
AG-TOU					0.00	(8.69)	(8.69)	
TOU-PA-5					0.00	(12.39)	(12.39)	
Default CPP rider > 200 kW								
AG-TOU								
2 p.m. to 6 p.m CPP Event Energy Charge - \$/kWh					0.00000	1.36229	1.36229	
Summer On Peak Demand Credit - \$/kW					0.00000	(8.69)	(8.69)	
TOU-PA-5								
2 p.m. to 6 p.m CPP Event Energy Charge - \$/kWh					0.00000	1.36229	1.36229	
Summer On Peak Demand Credit - \$/kW					0.00000	(12.39)	(12.39)	

ATTACHMENT F

Street Light Rate Group Settlement Agreement

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Southern California Edison)	
Company (U 338-E) To Establish Marginal)	Application 08-03-002
Costs, Allocate Revenues, And Design Rates)	(Filed March 4, 2008)
)	
In the Matter of the Application of Southern)	
California Edison Company (U 338-E) for)	Application 07-12-020
Authority to Make Various Electric Rate Design)	(Filed December 21, 2007)
Changes.)	

SOUTHERN CALIFORNIA EDISON COMPANY 2009 GRC, PHASE 2 STREET LIGHT RATE GROUP SETTLEMENT AGREEMENT

Dated: January 5, 2009

Phase 2 Street Light Rate Group Settlement Agreement

Parag	graph Title	Page
1.	Parties	1
2.	Recitals	2
3.	Definitions	2
4.	Agreement	4
5.	Implementation of Agreement	8
6.	Incorporation of Complete Agreement	8
7.	Signature Date	9
8.	Regulatory Approval	9
9.	Compromise Of Disputed Claims	9
10.	Non Precedent	9
11.	Previous Communications	9
12.	Non Waiver	9
13.	Effect Of Subject Headings	10
14.	Governing Law	10
15.	Number Of Originals	10
ATTACHME	ENT A ILLUSTRATIVE CHANGES TO NON-ENERGY CHARGES	(2009 - 2012)

SOUTHERN CALIFORNIA EDISON COMPANY 2009 GRC, PHASE 2 STREET LIGHT RATE GROUP SETTLEMENT AGREEMENT

This Phase 2 Street Light Rate Group 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), California City-County Street Light Association (CAL-SLA), and Pleasant Valley Recreation and Park District (PVRPD) (referred to hereinafter collectively as Parties or Settling Parties or individually as Party).

- 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.
- b. 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 Company and San Diego Gas & Electric Company.
- c. PVRPD is a recreation and park district, which was formed in 1962 under the California Public Resources Code. PVRPD owns and operates 27 public parks in or around Camarillo, California. Electricity service to these parks consists primarily of outdoor lighting and is provided by SCE. The outdoor lighting accounts are characterized by relatively high maximum demand and low load factors and are currently served on SCE's Schedule GS-2 because the accounts have some incidental load that cannot be limited to the dusk to dawn requirement of Schedule AL-2.

2. Recitals

- a. In Phase 2 of SCE's 2009 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 March 4, 2008, SCE served its initial prepared testimony regarding marginal costs, revenue allocation and rate design in Application 08-03-002.
 SCE updated its initial showing on June 27, 2008.
- c. In accordance with the Scoping Memo and Ruling of Assigned Commissioner, dated May 14, 2008, 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 12, 2008.
- d. DRA served its initial testimony on September 26, 2008. Interveners, including CAL-SLA and PVRPD served their initial testimony on October 31, 2008.
- e. Continuing settlement discussions occurred among the interested parties after November 12, 2008.
- f. The Parties have evaluated the impacts of the various proposals in this consolidated proceeding for A.08-03-002 and A.07-12-020 and desire to resolve all issues related to rate design for the Street Light Rate Group as indicated in Paragraph 4 of this Agreement.

3. <u>Definitions</u>

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. "Settling Parties" means SCE, CAL-SLA, and PVRPD.

- c. "Energy Charges" mean the dollar per kilowatt-hour (kWh) charges applicable to street and area lighting rate schedules. Energy Charges recover SCE's costs for delivery service and generation.
- d. "Customer Charges" mean the dollar per month charges applicable to certain Street Light Rate Group and traffic control rate schedules.
- e. "Non-Energy Charges" mean the distribution charges applicable to street and area lighting facilities owned and maintained by SCE. Non-Energy Charges are expressed as dollars per lamp per month. Non-Energy Charges are synonymous with "facilities charges", "service charges", and "other charges" applicable to street and area lighting.
- f. "Street Light Rate Group" means the following SCE rate schedules: Schedule LS-1 Lighting – Street and Highway Company-Owned System, Schedule LS-2 Lighting – Street and Highway Customer-Owned Installation – Unmetered Service, Schedule LS-3, Lighting – Street and Highway Customer-Owned Installation – Metered Service, Schedule OL-1 Outdoor Area Lighting Service, Schedule DWL Residential Walkway Lighting, and Schedule AL-2 Outdoor Area Lighting Service Metered.
- g. "Target Lamp Charges" mean Non-Energy Charges that shall be established as provided in Paragraph 4.c of this Agreement for the period from October 1, 2009 through rate changes implemented as a result of Phase 2 of SCE's 2012 general rate case (GRC).
- h. "Allocated Revenues" mean the amount of SCE's revenue requirement allocated to the Street Light Rate Group. Allocated Revenues are used to establish the Energy Charges applicable to the Street Light Rate Group.
- i. "Non-Allocated Revenues" mean the revenues collected from Non-Energy Charges. These costs are assigned directly to the Street Light Rate Group and are excluded from SCE's allocation of the revenue requirement to all rate groups. Non-Allocated Revenues for 2009, 2010, 2011, and 2012

shall be based on Non-Energy Charges calculated according to Paragraph 4 in this Agreement.

- j. "Functional SAPC Allocation" means allocation of SCE's revenue requirement to each of SCE's rate groups based on the system average percentage change for the particular function, *i.e.*, distribution or generation.
- k. "Commission" or "CPUC" means the California Public Utilities Commission.

4. Agreement

In consideration of the mutual obligations, covenants and conditions contained herein, the Settling Parties agree to the terms of this Agreement. Nothing in this Paragraph 4 of this Agreement shall be deemed to constitute an admission or an acceptance by any Party of any fact, principle, or position contained herein. This Agreement is subject to the express limitation on precedent described in Paragraph 10. The Parties, by signing this Agreement, acknowledge that they pledge support for Commission approval and subsequent implementation of all the provisions of the Agreement.

- a. The current rate structure, consisting of Customer Charges, Energy
 Charges and Non-Energy Charges shall be maintained for all applicable
 Street Light Rate Group and traffic control rate schedules.
- b. Effective October 1, 2009, the following Customer Charges shall be applicable: for traffic control (Schedule TC-1), \$14.75 per month per meter, for metered street lights with multiple service (Schedule LS-3), \$13.00 per month per meter, and for metered street lights with series service (Schedule LS-3), \$746.19 per month per meter.
- c. Non-Energy Charges shall change only according to the provisions set forth in Paragraph 4 of this Agreement and only by SCE advice letters filed in compliance with the provisions of Paragraph 4 of this Agreement.

- Illustrative changes to Non-Energy Charges calculated in accordance with these provisions are provided in Attachment A to this Agreement.
- d. In order to achieve a greater degree of control over future increases to the Non-Energy Charges, a targeted annual percentage increase of 4.8 percent (based on the average Handy-Whitman¹ escalation rate for mast arms and luminaries installed for the period 2003-2008) to Non-Energy Charges shall be established for schedules LS-1, LS-2, LS-3, DWL, and OL-1. This target annual percentage increase shall be used to calculate Target Lamp Charges for each Streetlight rate schedule in 2009, 2010, 2011, and 2012. The Target Lamp Charges for 2009 shall equal the December 2008 Non-Energy Charges increased by 4.8 percent. For each year thereafter from 2010 until rate changes are implemented as a result of Phase 2 of SCE's 2012 GRC, the Target Lamp Charges shall equal the product of the Target Lamp Charges for the prior year increased by 4.8 percent.
- e. Non-Energy Charges for 2009 that are implemented in accordance with Decision (D.) 06-06-067 and the settlement agreement adopted in Phase 2 of SCE's 2006 GRC (Application 05-05-023) will be in effect prior to October 1, 2009. Those Non-Energy Charges are expected to exceed the Target Lamp Charges for 2009. If so, there will be no increase to Non-Energy Charges when rate changes related to Phase 2 of SCE's 2009 GRC are first implemented on or after October 1, 2009. If Non-Energy Charges in effect prior to October 1, 2009 do not exceed the Target Lamp Charges for 2009, SCE shall increase such Non-Energy Charges to the Target Lamp Charges for 2009 when rate changes related to Phase 2 of SCE's 2009 GRC are first implemented on or after October 1, 2009.
- f. This Agreement shall apply to increase Non-Energy Charges when attrition revenue changes authorized by the Commission in Phase 1 of SCE's 2009 GRC are implemented in 2010 and 2011, and when the

- 5 -

The Handy-Whitman Index of Public Utility Construction Costs, "Cost Trends of Electric Utility Construction, Pacific Region" compiled and published by Whitman, Requardt & Associates, LLP

revenue change for Phase 1 of SCE's 2012 GRC is implemented, subject to the following conditions:

- 1. Non-Energy Charges for 2010 (adjusted for the 2009 GRC attrition year 2010 revenue increase) shall increase based on the functional System Average Percentage Change (SAPC) if the actual Non-Energy Charge in effect prior to January 1, 2010 is less than the Target Lamp Charge for 2010 provided that the Non-Energy Charge for 2010 shall not exceed the Target Lamp Charge for 2010. If however, the actual Non-Energy Charge in effect prior to January 1, 2010 exceeds the Target Lamp Charge for 2010, the Non-Energy Charge for 2010 shall not change.
- 2. Non-Energy Charges for 2011 (adjusted for the 2009 GRC attrition year 2011 revenue increase) shall increase based on the functional SAPC if the actual Non-Energy Charge in effect prior to January 1, 2011 is less than the Target Lamp Charge for 2011 provided that the Non-Energy Charge for 2011 shall not exceed the Target Lamp Charge for 2011. If however, the actual Non-Energy Charge in effect prior to January 1, 2011 exceeds the Target Lamp Charge for 2011, the Non-Energy Charge for 2011 shall not change.
- 3. When the revenue requirement change for SCE's 2012 GRC is implemented, Non-Energy Charges for 2012 shall increase based on the functional SAPC if the actual Non-Energy Charge in effect prior to January 1, 2012 is less than the Target Lamp Charge for 2012 provided that the Non-Energy Charge for 2012 shall not exceed the Target Lamp Charge for 2012. If however, the actual Non-Energy Charge in effect prior to January 1, 2012 exceeds the Target Lamp Charge for 2012, the Non-Energy Charge for 2012 shall not change.
- g. Any revenue deficiency associated with the establishment of Non-Energy Charges for Street Light Rate Group rate schedules in accordance with Paragraphs 4.e and 4.f of this Agreement shall be recovered from all rate

- groups, with the deficiency allocated on the basis of distribution related revenues. This provision is subject to the filing in this proceeding and CPUC approval of a separate revenue allocation settlement agreement which also adopts the substance of this paragraph.
- h. Changes to Allocated Revenues collected by Energy Charges and Customer Charges for the Street Light Rate Group and traffic control schedules shall be implemented on a Functional SAPC basis whenever changes to SCE's authorized revenues are implemented.
- Distribution-related revenue allocations will not include streetlight facilities-related costs (*i.e.*, Non-Allocated Revenues) in determining the Street Light Rate Group's revenue responsibility.
- j. Effective January 1, 2010, the costs for a Standard Installation defined in Special Condition 2 of Schedule LS-1 and used to establish a Differential Facilities rate, pursuant to Special Condition 11 of Schedule LS-1, shall equal the December 2009 Standard Installation costs increased by 4.8 percent. For each year thereafter until rate changes are implemented as a result of Phase 2 of SCE's 2012 GRC, the Standard Installation cost shall equal the product of the Standard Installation cost for the prior year increased by 4.8 percent.
- k. SCE and CAL-SLA shall work together on a joint study prior to SCE's next GRC to better understand the costs to construct, install, own, and maintain street light facilities and to identify the sources of revenues that pay for the recovery of these costs.
- Schedule AL-2 shall be modified to include two options: Option A and
 Option B. Outdoor area lighting customers without daytime incidental
 loads shall receive service on Schedule AL-2, Option A. Schedule AL-2,
 Option A, shall retain the same limits on incidental load and rate structure
 as in SCE's existing Schedule AL-2.
- m. Schedule AL-2, Option B, shall allow incidental load up to 15 percent of the maximum monthly peak demand, whether such incidental load occurs in the daytime or nighttime, provided that daytime incidental load shall not

- exceed 20 kilowatts (kW). Schedule AL-2, Option B, shall also require a meter capable of providing interval metering data, which shall be provided by SCE, subject to meter availability, with no incremental meter charges.
- n. Schedule AL-2, Option B, shall consist of on-peak and off-peak energy charges as well as a customer charge. The on-peak energy charge shall be equal to the Schedule GS-1 seasonal energy charge and shall apply year-round during the hours of 8:00 am to 4:00 pm on weekdays, weekends, and holidays. The off-peak energy charge for Schedule AL-2, Option B, shall be the same as the energy charge for Schedule AL-2, Option A. The customer charge for Schedule AL-2, Option B, shall be the same as the customer charge for Schedule AL-2, Option A.
- o. Customers with outdoor area lighting service shall be removed from service on either Option A or Option B of Schedule AL-2 if the applicable incidental load limits are exceeded during any three months in a twelve-month period.

5. Implementation of Agreement

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 but no earlier than October 1, 2009.

6. 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 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.

7. <u>Signature Date</u>

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

8. 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.

9. <u>Compromise Of Disputed Claims</u>

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.

10. Non Precedent

Consistent with Rule 12.5 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 or unless the Commission expressly provides otherwise.

11. 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.

12. 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.

13. Effect Of Subject Headings

Subject headings in this Agreement are inserted for convenience only, and shall

not be construed as interpretations of the text.

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.

15. 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.

SOUTHERN CALIFORNIA EDISON COMPANY

By: /s/ Bruce A. Reed

Title: Senior Attorney Date: 1/19/2009

- 10 -

CALIFORNIA CITY-COUNTY STREET LIGHT ASSOCIATION

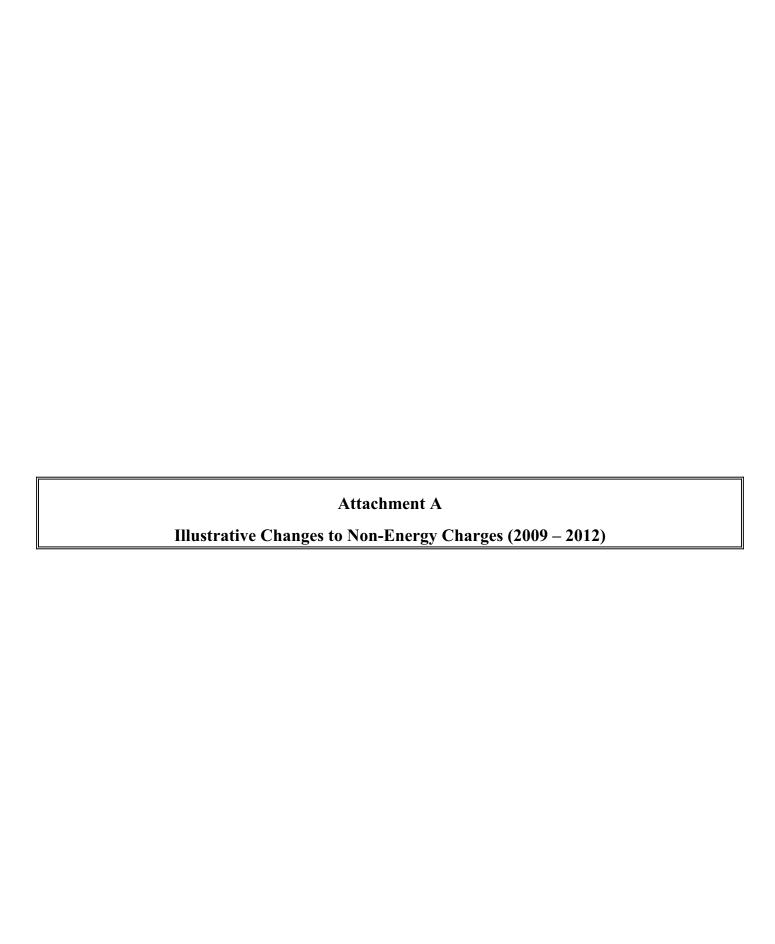
By: /s/ Reed V. Schmidt

Title: Energy Consultant Date: 1/8/2009

PLEASANT VALLEY RECREATION AND PARK DISTRICT

By: /s/ Mark Carlson

Title: Financial Supervisor Date: 1/8/2009



Illustrative Changes to Non-Energy Charges (2009 - 2012) Pursuant to Paragraph 4 of Settlement Agreement

Example: 100-watt HPSV, Schedule LS-1

	Target Lamp	Assumed	Calculated	
	Charge (2009 -	SAPC %	SAPC Non-	Actual Non-
Year	2012)	Increase	Energy Charge	Energy Charge
1-Dec-2008				\$8.16
1-Jan-2009		3.3%	\$8.43	\$8.43
1-Mar-2009	\$8.55	8.2%	\$9.12	\$9.12
1-Oct-2009		0.0%	\$9.12	\$9.12
1-Jan-2010	\$8.96	5.0%	\$9.58	\$9.12
1-Jan-2011	\$9.39	4.0%	\$9.48	\$9.39
1-Jan-2012	\$9.84	6.0%	\$9.95	\$9.84

Settlement effective on October 1, 2009

ATTACHMENT G

Commercial Submetering Settlement Agreement

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Southern California Edison)	
Company (U 338-E) To Establish Marginal)	Application 08-03-002
Costs, Allocate Revenues, And Design Rates)	(Filed March 4, 2008)
)	
In the Matter of the Application of Southern)	
California Edison Company (U 338-E) for)	Application 07-12-020
Authority to Make Various Electric Rate Design)	(Filed December 21, 2007)
Changes.)	

SOUTHERN CALIFORNIA EDISON COMPANY 2009 GRC
PHASE 2 COMMERCIAL SUBMETERING SETTLEMENT AGREEMENT

Dated: January 12, 2009

Commercial Submetering Settlement Agreement

Parag	raph Title	Page
1.	Parties	1
2.	Recitals	2
3.	Definitions	3
4.	Agreement	4
5.	Implementation of Agreement	6
6.	Incorporation of Complete Agreement	7
7.	Signature Date	7
8.	Regulatory Approval	7
9.	Compromise Of Disputed Claims	7
10.	Non Precedent	7
11.	Previous Communications	8
12.	Non Waiver	8
13.	Effect Of Subject Headings	8
14.	Governing Law	8
15.	Number Of Originals	8
ATTACHME	NT APR	OPOSED SCE RULE 18

SOUTHERN CALIFORNIA EDISON COMPANY 2009 GRC PHASE 2 COMMERCIAL SUBMETERING SETTLEMENT AGREEMENT

This Phase 2 Commercial Submetering 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), Simon Property Group (Simon); and the Building Owners and Managers Associations of Greater Los Angeles, Orange County, San Francisco, and California (BOMA) (referred to hereinafter collectively as Parties or Settling Parties or individually as Party).

- 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.
- b. Simon is a fully integrated real estate company with an interest in over 350 shopping centers worldwide, including properties located in the SCE service area.
- c. 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.

2. Recitals

- a. In Phase 2 of SCE's 2009 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 March 4, 2008, SCE served its initial prepared testimony regarding marginal costs, revenue allocation and rate design in Application 08-03-002. SCE updated its initial showing on June 27, 2008. In its testimony, SCE proposed to revise its Rule 18 to allow owners of certain commercial buildings to submeter their tenants in connection with the provision of electricity and subject to certain terms and conditions (SCE Submetering Proposal). The purpose of submetering is to provide nonresidential tenants price signals and information about their energy usage and costs, and to provide the opportunity for tenants to participate in energy conservation or load management programs.
- c. In accordance with the Scoping Memo and Ruling of Assigned Commissioner, dated May 14, 2008, 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 12, 2008.
- d. DRA served its initial testimony on September 26, 2008. Interveners, including Simon and BOMA served their initial testimony on October 31, 2008.
- e. Simon served its testimony on October 31, 2008. That testimony supported SCE's Submetering Proposal but opposed SCE's limitation of commercial submetering to high-rise buildings.
- f. BOMA served its testimony on October 31, 2008. That testimony supported SCE's Submetering Proposal. However, BOMA proposed to achieve a settlement so that commercial submetering could go into effect in SCE's service territory by January 1, 2009, instead of October 1, 2009.

- g. The Energy Division of the Commission expressed an interest to SCE and the parties that SCE customers who were interested in pursuing commercial submetering should be made aware of certain protective provisions that were proposed by TURN in a PG&E proceeding (A.06-03-005) and were adopted by the Commission in D.07-09-004.
- h. Continuing settlement discussions occurred among the interested parties after November 12, 2008.
- The Parties have evaluated the impacts of the various proposals in this
 consolidated proceeding for A.08-03-002 and A.07-12-020 and desire to
 resolve all issues related to commercial submetering as indicated in
 Paragraph 4 of this Agreement.

3. <u>Definitions</u>

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. "Commission" or "CPUC" means the California Public Utilities Commission.
- c. "Premises" shall have the meaning as defined in SCE's Rule 1, which is entitled "Definitions."
- d. "Settling Parties" means SCE, Simon, and BOMA.
- e. "Rule 18" means SCE's tariff, which is entitled "Supply to Separate Premises and Use by Others" that deals with, among other things, the metering and provision of electricity to tenants in nonresidential buildings or developments on a single Premises.

4. Agreement

In consideration of the mutual obligations, covenants and conditions contained herein, the Settling Parties agree to the terms of this Agreement. Nothing in this Paragraph 4 of this Agreement shall be deemed to constitute an admission or an acceptance by any Settling Party of any fact, principle, or position contained herein. This Agreement is subject to the express limitation on precedent described in Paragraph 10. The Settling Parties, by signing this Agreement, acknowledge that they pledge support for Commission approval and subsequent and timely implementation of all the provisions of the Agreement.

- a. SCE shall continue to require a single meter for each tenant or enterprise located in a single, nonresidential premises except where such service in SCE's opinion is impractical or where the Commission has authorized SCE to supply electric service through a single meter pursuant to Rule 18, as revised by this Settlement Agreement. A revised Rule 18 is set forth in Attachment A to this Settlement Agreement.
- b. Where SCE provides electric service through a single meter to a customer's nonresidential premises, nonresidential tenants at the premises may be submetered and billed for electric service, irrespective of whether the premises is a high-rise building, subject to the following conditions:
 - Submetering of electric usage by nonresidential tenants shall be subject to the mutual agreement of the customer and the nonresidential tenant.
 - 2. A customer who provides submetered service to nonresidential tenants shall be allowed to recover the costs of metering, billing, and information services, according to terms jointly agreed to by tenants and the customer and specified in leases. Nothing in this Agreement prevents the customer from separately charging tenants for submetering and energy information services, including the amortized cost of re-wiring, meter and data server hardware and software costs, and ongoing meter and meter data systems

- operations, maintenance and administrative costs, as authorized by the Commission in D.07-09-004 and according to terms jointly agreed to by tenants and a customer and specified in leases.
- 3. The customer shall provide all nonresidential tenants with the following information:
 - a. The SCE rate schedule that applies to service to the customer.
 - b. Contact information for SCE customer service.
 - c. Contact information for the California Department of Food and Agriculture, Division of Measurement Standards meter complaint process.
 - d. Information concerning dynamic pricing options and all energy conservation and load management programs available for tenant participation.
- 4. The customer shall install and maintain meters of comparable accuracy as utility revenue meters for nonresidential tenants, subject to all applicable safety rules, regulations, and general orders established by the State of California and its subdivisions and local governments and their subdivisions. Common areas shall be separately metered.
- 5. The rates and charges billed to nonresidential tenants by the customer for the electricity provided by SCE to the customer and used by such tenants shall be the same as the total amount billed by SCE to the customer. The customer shall apportion or prorate fixed monthly charges (*e.g.*, customer or demand) among the submetered tenants such that the total amount billed to submetered tenants equals the amount billed by SCE to the customer.
- 6. Bills for tenant electric usage shall resemble bills rendered by SCE for comparable service and must include the following information:

- a. Energy (kWh) and demand (kW) and associated charges by time-of-use (TOU) period in the same level of detail as shown on SCE's bill to the customer.
- b. Energy and demand charges allocated to the tenant for common area usage, and other consumption exclusive of tenant measured usage. Such allocations should be in accordance with methods specified in leases (such as square footage of occupied space) and shall not be based on tenant measured usage.
- c. Charges for submetering, and billing and information services provided by the customer.
- d. Sufficient information to permit tenants to replicate customer's bill calculations.
- 7. When a customer at an existing premises where energy charges for tenants are absorbed in a lease begins billing tenants for submetered electric service, the customer shall account for and credit tenants' rental charges to reflect removal of the related tenant-controlled energy charges on a prospective basis for the duration of the lease.
- c. Customers or representatives of customers who provide submetered service to nonresidential tenants should provide information to SCE that is necessary to evaluate the effects of this commercial submetering service on energy consumption of nonresidential tenants. Provided that sufficient information is available, SCE's testimony in Phase 2 of SCE's 2012 GRC will include the results of a survey regarding the impact on electric usage of submetered nonresidential tenants.

5. Implementation of Agreement

It is the intent of the Settling Parties that SCE should be authorized to implement the revisions to Rule 18 resulting from this Agreement as soon as practicable following the issuance of a final Commission decision approving this Agreement.

6. <u>Incorporation of Complete Agreement</u>

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 Settling Parties acknowledge that changes, concessions, or compromises by a Settling Party or the Settling Parties in one section of this Agreement resulted in changes, concessions, or compromises by the Settling Parties in other sections. Consequently, the Settling Parties agree to oppose any modification of this Agreement not agreed to by all Settling Parties.

7. <u>Signature Date</u>

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

8. Regulatory Approval

The Settling Parties shall use their best efforts to obtain timely Commission approval of the Agreement. The Settling 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.

9. <u>Compromise Of Disputed Claims</u>

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

10. Non Precedent

Consistent with Rule 12.5 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 or unless the Commission expressly provides otherwise.

11. Previous Communications

The Agreement contains the entire agreement and understanding between and among the Settling Parties as to the subject matter of this Agreement, and supersedes all prior agreements, commitments, representation, and discussions between and among the Settling Parties.

12. Non Waiver

None of the provisions of this Agreement shall be considered waived by any Settling Party unless such waiver is given in writing. The failure of a Settling 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.

13. <u>Effect Of Subject Headings</u>

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

14. 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.

15. 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 Settling Party represented.

SOUTHERN CALIFORNIA EDISON COMPANY

By: /s/ Bruce A. Reed

Title: Senior Attorney Date: 1/20/2009

SIMON PROPERTY GROUP, INC.

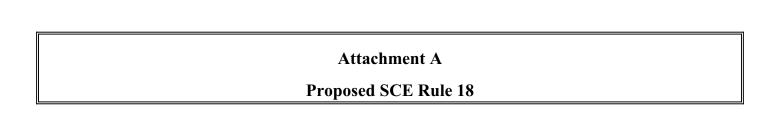
By: /s/ S.F. Greenwald

Title: Attorney Date: 1/20/2009

BOMA

By: /s/ B. F. Roberts

Title: President, Economic Sciences Corp. Date: 1/15/2009



Revised Cal. PUC Sheet No. Cancelling Revised Cal. PUC Sheet No.

Sheet 1

Rule 18 SUPPLY TO SEPARATE PREMISES AND USE BY OTHERS

- A. Separate Metering. Separate Premises will not be supplied through the same meter nor will the electric loads of such separately metered Premises be aggregated physically, electronically or otherwise, except as may be specifically provided for in the tariff schedules.
- B. Nonresidential Loads. In accordance with Rule 16, electric service shall be individually metered to each tenant in a non-residential building or group of buildings or other development on a single Premises with multiple tenants or enterprises. However, where, in the opinion of SCE, it is impractical to meter each tenant individually or where the Commission has authorized SCE to supply electric service through a single meter, SCE may provide service through a single meter subject to the provisions of Sections E and H below.

Buildings originally constructed for a non-residential purpose that subsequently converted to residential use on or after December 7, 1981 without the need for a building permit shall be eligible to convert from their prior rate schedule to an existing applicable domestic service submetering rate schedule. Any non-residential building converted to residential use, for which a building permit was required on or after July 1, 1982, must be separately metered by SCE.

- C. Other Uses or Premises. A customer shall not use electricity received from SCE upon other Premises, except for SCE's operating convenience, nor for other purposes than those specified in the customer's application or in the rate schedule applied.
- D. Customer with Multiple Service Accounts/Meters at a Single Premises. When a customer (single enterprise) occupies a single Premises with multiple service accounts/meters, the readings of such meters shall not be combined for billing purposes except as provided for in Rule 9.B. However, if the customer physically aggregates the electric loads of such multiple service accounts/meters into a single service account (master meter), the account will be provided service under an applicable rate schedule.
- E. Use by Others. A customer shall not charge for electricity received from SCE and used by another person, except:
 - 1. Where energy is purchased at rates specifically applicable to resale service; or
 - 2. Where the charge to domestic or nondomestic tenants is absorbed in the rental for the Premises or space occupied, is not separately identified, and does not vary with electrical usage, or where all of the following conditions are met for non-domestic service:

(C)(L) (N)

(N)

- a. Service to the customer is supplied to a single meter (master meter) located in a commercial building or development on a single Premises;
- b. The customer installs and maintains meters of comparable accuracy as utility revenue meters for nondomestic tenants subject to all applicable safety rules, regulations, and general orders established by the State of California and its subdivisions and local governments and their subdivisions.
- c. Submetering of electric usage by nondomestic tenants shall be subject to the mutual agreement of the customer and the nondomestic tenant.

(Continued)

(To be inserted by utility)		Issued by	(To be inserted by Cal. PUC)		
Advice	GRC 2009-P2W	Akbar Jazayeri	Date Filed		
Decision		Vice President	Effective		
1D7			Resolution		

Revised Cal. PUC Sheet No. Cancelling Revised Cal. PUC Sheet No.

Sheet 2

Rule 18 SUPPLY TO SEPARATE PREMISES AND USE BY OTHERS

(Continued)

- E. Use by Others. (Continued)
 - 2. (Continued)
 - d. The customer shall provide all nondomestic tenants with the following information:
 - (1) The SCE rate schedule that applies to service to the customer.
 - (2) Contact information for SCE customer service.
 - (3) Contact information for the California Department of Food and Agriculture, Division of Measurement Standards meter complaint process.
 - (4) Information concerning dynamic pricing options and all energy conservation and load management programs available for tenant participation.
 - e. Bills for tenant electric usage shall resemble bills rendered by SCE for comparable service and must include the following information:
 - (5) Energy (kWh) and demand (kW) and associated charges by time-of-use (TOU) period in the same level of detail as shown on SCE's bill to the customer.
 - (6) Energy and demand charges allocated to the tenant for common area usage, and other consumption exclusive of tenant measured usage. Such allocations should be in accordance with methods specified in leases (such as square footage of occupied space) and shall not be based on tenant measured usage.
 - (7) Charges for submetering, and billing and information services provided by the customer.
 - (8) Sufficient information to permit tenants to replicate customer's bill calculation.
 - f. The rates and charges billed by the customer to nondomestic tenants, in total, for the electricity provided by SCE to the customer and used by such tenants shall be the same as the rates and charges billed by SCE to the customer. The customer shall apportion or prorate fixed monthly charges (e.g., customer, peak demand) among submetered tenants such that the total amount billed to submetered tenants equals the amount billed to the customer by SCE.

(Continued)

(To be inserted by utility)					
Advice	GRC 2009-P2W				
Decision					
209					

Issued by <u>Akbar Jazayeri</u> <u>Vice President</u>

(To be inserted by Cal. PUC)					
Date Filed					
Effective					
Resolution					

Decision

3D13

	Revised	Cal. PUC Sheet No.
Cancelling	Original	Cal. PUC Sheet No.

			Rule 18 SUPPLY TO SEPARATE PREMISES AND USE BY OTHERS	Sheet 3	(T)	
			(Continued)			
E.	Use by	Others.	(Continued)			
	2.	(Contin	nued)			
		g.	When a customer at an existing Premises where energy charg are absorbed in a lease begins billing tenants for submetered et the customer shall adjust rental charges such that charges for ter energy usage are not also reflected in the lease. Charges for more customer-controlled energy usage (e.g., common area usage) to be included in rental charges.	lectric service, nant-controlled aster metered	(T) (L)	
	3. Where the customer is the owner, lessee, or operator of a multifamily accommodation and submeters electricity furnished for use by a domestic tenant in a single-family dwelling at the same rates that SCE would charge for the service if supplied directly and such customer's account is eligible for service under Schedule DMS-1 or DMS-2. In such cases, said owner, lessee, or operator shall furnish, install, maintain, and test the submeters. This electrical usage applies only to the single-family dwellings and excludes other electrical usage such as for swimming pools, recreation rooms, or laundry facilities which are used in common by tenants. In addition, said owner, lessee, or operator served under Schedule DMS-2 may elect to have SCE perform mobilehome park bill calculation services in accordance with the provisions contained within Schedule DMS-2 and Form 14-774, Bill Calculation Service Agreement. 4. As provided in Sections F and G below.					
	4. As provided in Sections F and G below.					
	 As provided in Sections F and G below. All energy use, including use by others, supplied through a single SCE meter is the responsibility of the customer of record. 					
F.	responsibility of the customer of record.					
			(Continued)			
		ed by uti		erted by Cal. P	UC)	
Advid	.е <u>-</u> С	RC 2009	9-P2W <u>Akbar Jazayeri</u> Date Filed	i		

Vice President

Effective Resolution

Original Cancelling

Cal. PUC Sheet No. Cal. PUC Sheet No.

Rule 18 SUPPLY TO SEPARATE PREMISES AND USE BY OTHERS (Continued) (Continued) (Continued) (Continued) (Continued) (L) aboard an ocean-going vessel at the Port of Long Beach or the Port of Hueneme but may not submeter any other load or land-based facility. If the master-metered customer submeters cold-ironing load to an ocean-going vessel, the rates and charges to the submetered user for services supplied by SCE must not exceed the rates and charges the master-metered customer is billed by SCE froust not exceed the rates and charges the master-metered customer is billed by SCE froust not exceed the rates and charges the master-metered customer is billed by SCE froust not exceed the rates and charges the master-metered user for services supplied electricity for the lights, heating, cooling, machinery, and other needs of an ocean-going vessel while at berth or otherwise electrically connected, as replacement for the vessel's auxiliary internal combustion engines. H. Resale of Electricity. Resale of electricity or submetering of electricity for the purpose of resale is prohibited, except as provided for under Section E.1, E.2, E.3, F. or G above. (I) Violation of any provision of this Rule shall result in discontinuance of electricity, or refusal to provide service, in accordance with Rule 11.G. I. Direct Access. When SCE delivers electric power purchased by an ESP to a master-metered Direct Access Customer, such Customer is subject to the provisions of Section E, F, or G above regarding SCE's charges for such delivery. (END OF ATTACHMENT G)			
G. Cold-Ironing Load. A master-metered customer may submeter a tenant's cold-ironing load aboard an ocean-going vessel at the Port of Long Beach or the Port of Hueneme but may not submeter any other load or land-based facility. If the master-metered customer submeters cold-ironing load to an ocean-going vessel, the rates and charges to the submetered user for services supplied by SCE must not exceed the rates and charges the master-metered customer is billed by SCE for such services. Cold-ironing load is defined as the use of shore-supplied electricity for the lights, heating, cooling, machinery, and other needs of an ocean-going vessel while at berth or otherwise electrically connected, as replacement for the vessel's auxiliary internal combustion engines. H. Resale of Electricity. Resale of electricity or submetering of electricity for the purpose of resale is prohibited, except as provided for under Section E.1, E.2, E.3, F, or G above. Violation of any provision of this Rule shall result in discontinuance of electricity, or refusal to provide service, in accordance with Rule 11.G. I. Direct Access. When SCE delivers electric power purchased by an ESP to a master-metered Direct Access Customer, such Customer is subject to the provisions of Section E, F, or G above regarding SCE's charges for such delivery. (L)			(T)
G. Cold-Ironing Load. A master-metered customer may submeter a tenant's cold-ironing load aboard an ocean-going vessel at the Port of Long Beach or the Port of Hueneme but may not submeter any other load or land-based facility. If the master-metered customer submeters cold-ironing load to an ocean-going vessel, the rates and charges to the submetered user for services supplied by SCE must not exceed the rates and charges the master-metered customer is billed by SCE for such services. Cold-ironing load is defined as the use of shore-supplied electricity for the lights, heating, cooling, machinery, and other needs of an ocean-going vessel while at berth or otherwise electrically connected, as replacement for the vessel's auxiliary internal combustion engines. H. Resale of Electricity. Resale of electricity or submetering of electricity for the purpose of resale is prohibited, except as provided for under Section E.1, E.2, E.3, F, or G above. Violation of any provision of this Rule shall result in discontinuance of electricity, or refusal to provide service, in accordance with Rule 11.G. I. Direct Access. When SCE delivers electric power purchased by an ESP to a master-metered Direct Access Customer, such Customer is subject to the provisions of Section E, F, or G above regarding SCE's charges for such delivery. (L)		(Continued)	
and charges to the submetered user for services supplied by SCE must not exceed the rates and charges the master-metered customer is billed by SCE for such services. Cold-ironing load is defined as the use of shore-supplied electricity for the lights, heating, cooling, machinery, and other needs of an ocean-going vessel while at berth or otherwise electrically connected, as replacement for the vessel's auxiliary internal combustion engines. H. Resale of Electricity. Resale of electricity or submetering of electricity for the purpose of resale is prohibited, except as provided for under Section E.1, E.2, E.3, F, or G above. (T) Violation of any provision of this Rule shall result in discontinuance of electricity, or refusal to provide service, in accordance with Rule 11.G. I. Direct Access. When SCE delivers electric power purchased by an ESP to a master-metered Direct Access Customer, such Customer is subject to the provisions of Section E, F, or G above regarding SCE's charges for such delivery. (L)	G.	Cold-Ironing Load. A master-metered customer may submeter a tenant's cold-ironing load aboard an ocean-going vessel at the Port of Long Beach or the Port of Hueneme but may not	(L)
cooling, machinery, and other needs of an ocean-going vessel while at berth or otherwise electrically connected, as replacement for the vessel's auxiliary internal combustion engines. H. Resale of Electricity. Resale of electricity or submetering of electricity for the purpose of resale is prohibited, except as provided for under Section E.1, E.2, E.3, F, or G above. Violation of any provision of this Rule shall result in discontinuance of electricity, or refusal to provide service, in accordance with Rule 11.G. I. Direct Access. When SCE delivers electric power purchased by an ESP to a master-metered Direct Access Customer, such Customer is subject to the provisions of Section E, F, or G above regarding SCE's charges for such delivery. (L)		and charges to the submetered user for services supplied by SCE must not exceed the rates	
is prohibited, except as provided for under Section E.1, E.2, E.3, F, or G above. Violation of any provision of this Rule shall result in discontinuance of electricity, or refusal to provide service, in accordance with Rule 11.G. I. Direct Access. When SCE delivers electric power purchased by an ESP to a master-metered Direct Access Customer, such Customer is subject to the provisions of Section E, F, or G above regarding SCE's charges for such delivery. (L)		cooling, machinery, and other needs of an ocean-going vessel while at berth or otherwise	
provide service, in accordance with Rule 11.G. I. Direct Access. When SCE delivers electric power purchased by an ESP to a master-metered Direct Access Customer, such Customer is subject to the provisions of Section E, F, or G above regarding SCE's charges for such delivery. (L)	Н.		 (T)
Direct Access Customer, such Customer is subject to the provisions of Section E, F, or G above regarding SCE's charges for such delivery. (L)			
(END OF ATTACHMENT G)	I.	Direct Access Customer, such Customer is subject to the provisions of Section E, F, or G above	 (L)
		(END OF ATTACHMENT G)	
		(END OF THE MELLIN O)	

(To be inserted by utility)						
Advice	GRC 2009-P2W					
Decision						
4D9						

Issued by

<u>Akbar Jazayeri</u>

<u>Vice President</u>

(To be inserted by Cal. PUC)					
Date Filed					
Effective					
Resolution					

ATTACHMENT H

Rate Design Guidance¹

All Dynamic Pricing Rates

- Rate design should promote economically efficient decisionmaking.
- To promote economically efficient decision-making, rates should be based on marginal cost.
- Other objectives, such as energy efficiency, and legal requirements, such as baseline allowances, should be addressed when designing specific rates, and any deviation from marginal cost should be minimized.
- Rates should also seek to provide stability, simplicity and customer choice.
- If customers on a particular rate reduce their usage in a manner that reduces a utility's costs then the customers on that rate should see a commensurate reduction in their bills.
- Dynamic pricing rates should include a capacity reservation charge, or a similar feature, that allows a customer to pay a fixed charge for a predetermined amount of its load and pay the dynamic price for consumption in excess of the reserved capacity.
- Customers should have the opportunity to opt out of a default dynamic pricing rate to another time-variant rate.
- Utilities should offer optional bill protection to customers on default dynamic pricing rates.

¹ From Decision 08-07-045, Attachment A.

• The utilities should bid demand reductions due to dynamic pricing into the California Independent System Operator's (CAISO's) day-ahead market.

Critical Peak Pricing

- The critical peak price should represent the marginal cost of capacity used to meet peak energy needs plus the marginal cost of energy during the critical peak period.
- The utility should explain what it used as the basis for the marginal cost of capacity in its critical peak pricing (CPP) rate and why. The annualized cost of a new combustion turbine is a reasonable proxy for determining the marginal capacity prices; however, alternative bases include actual utility costs, CAISO scarcity prices (if adopted by the Federal Energy Regulatory Commission and implemented by the CAISO), and centralized capacity market or bulletin board prices (if implemented)
- Critical peak pricing rates should include a critical peak price during critical peak periods and time-of-use rates during noncritical periods.
- Since the critical peak price is intended to reflect the marginal cost of generation that is needed to meet peak period usage, CPP rates should not also have summer generation demand charges.
- The utilities should be able to call a variable number of events each year, and the rate should be designed based on the number of events that would be called during a typical year.
- The utilities should be able to call critical peak events any day of the week, year round.

Real-Time Pricing

- The energy charge should be indexed to the CAISO's dayahead hourly market prices.
- At least initially, RTP should be based on day-ahead hourly market prices that have been aggregated across PG&E's service territory. As the market develops, locational prices should be considered.
- The Commission should determine the degree to which the marginal cost of capacity is not incorporated into the CAISO's day-ahead hourly market prices.

(END OF ATTACHMENT H)



REVISED APPENDIX B TO REVENUE ALLOCATION SETTLEMENT AGREEMENT

Phase 2 Revenue Allocation Settlement Agreement
Bundled Service Rate Groups
Illustrative Rates

			Oct. 1,	Proposed				Percent	of System
	Dec. 2008	Apr. 2009	2009	Settlement	Relative Percentage Change		Avera	Average Rate	
	A	В	С	D	B/A	C/A	D/A	(A)	(D)
Total Domestic	14.9	15.5	16.0	16.5	4.12%	6.96%	10.68%	109%	111%
GS-1	16.9	17.3	17.1	17.7	2.09%	0.95%	4.59%	123%	119%
TC-1	15.1	15.2	16.1	16.8	0.27%	6.54%	10.68%	110%	113%
GS-2	14.5	15.1	15.5	16.1	3.75%	7.06%	10.68%	106%	108%
TOU-GS-3	13.2	13.4	13.1	13.6	1.63%	-0.57%	2.83%	96%	92%
Total LSMP	14.6	15.0	15.1	15.7	2.99%	3.96%	7.53%	106%	106%
TOU-8-Sec	12.4	12.5	12.6	13.0	0.63%	1.66%	4.84%	90%	88%
TOU-8-Pri	11.7	11.8	11.5	11.9	0.60%	-1.42%	1.68%	85%	80%
TOU-8-Sub	7.6	7.5	8.2	8.4	-2.32%	8.06%	10.68%	56%	57%
Total Large Power	10.8	10.7	11.0	11.3	-0.36%	1.78%	4.80%	79%	76%
PA-1	18.6	18.9	18.3	19.0	1.82%	-1.86%	1.93%	135%	128%
PA-2	13.0	13.2	13.4	13.9	1.50%	3.21%	6.69%	95%	94%
AG-TOU	9.7	9.2	10.4	10.7	-5.66%	7.20%	10.68%	71%	73%
TOU-PA-5	9.5	9.3	10.2	10.5	-2.46%	7.36%	10.68%	69%	71%
Total Ag.&Pumping	11.2	10.9	11.7	12.1	-2.91%	4.25%	7.73%	82%	81%
Total Street Lighting	18.6	19.2	19.5	19.9	3.14%	4.55%	6.81%	136%	134%
Total System	13.7	14.0	14.3	14.8	2.29%	4.43%	7.93%	100%	100%

System Average Increase from December 2008 = 7.93% Revenue Allocation Percentage Cap = 2.75% Maximum Allocated Percentage Increase = 10.68%

Notes:

Column A: Actual rates effective December 2008

Column B: Actual rates effective April 2009 include the impact of Phase 1 of SCE's 2009 GRC. This revised revenue requirement (June 2009 Forecast) reflects reductions compared to the December 2008 Forecast that were reflected in the Settlement Agreement, comprised primarily of a DWR Power Charge reduction of \$443 million, a decrease in energy efficiency revenues of \$173 million, and a decrease due to changes in the recorded levels of transmission balancing accounts.

Column C: Rates effective October 1, 2009 are based on the June 2009 Forecast revenue requirement, adjusted to achieve the same effective allocation of revenues to each rate group as shown in Column D, where allocated revenues are subject to the 2.75% cap. The SAPC increase from April to October 1, 2009 for bundled-service customers reflects the elimination of the DA-CRS undercollection payment component of 1.8 cents/kWh for large DA customers.

Column D: Forecast rates are based on the estimated adjusted revenue requirement (Paragraph 5.b.ii), which excludes the impact of one-time revenue reductions reflected in 2009 rates, such as 1) the suspension of SCE's collection of the CSI revenue requirement in compliance with D.08-12-004; 2) the refund of certain PBR rewards and other revenues ordered by D.08-09-038; and 3) the refund of unspent CEC Renewables monies. Forecast rates do not assume repayment by "small" bundled-service customers of the \$95 million "loan" made by large bundled-service customers because the undercollection component of the DA CRS for DA small customers will not have been recovered until some time after 2010.

Bundled Service Revenues Forecast October 1, 2009 Revenue Requirement (\$MM)

					İ				Total Gen
				Total			DWR		and
	Trans	Dist.	Other	Delivery		URG Gen.	Power	Total Gen.	Delivery
Total Residential	190.1	1,622.7	214.6	2,027.4		2,082.6	513.0	2,595.6	4,623.0
GS-1	34.4	283.9	42.7	361.0		385.1	86.2	471.3	832.3
TC-1	0.3	4.6	0.5	5.3		2.8	1.0	3.8	9.1
		701.5		915.2					
GS-2	94.1		119.6			1,056.5	251.4	1,307.9	2,223.1
TOU-GS-3	46.0	293.7	61.9	401.6		465.0	133.6	598.6	1,000.2
Total LSMP	174.8	1,283.7	224.6	1,683.1		1,909.3	472.2	2,381.6	4,064.7
TOU-8-Sec	43.1	222.5	63.7	329.3		541.6	141.2	682.9	1,012.2
									,
TOU-8-Pri	25.4	114.0	40.0	179.3		321.4	89.8	411.2	590.5
TOU-8-Sub	24.6	36.0	40.3	100.9		281.0	92.5	373.5	474.4
Total Large Power	93.1	372.4	143.9	609.5		1,144.1	323.5	1,467.6	2,077.0
- · · · · · · · · · · · · · · · · · · ·						,,		.,	_,
PA-1	2.5	29.1	3.6	35.1		29.9	7.0	36.9	72.0
PA-2	1.3	13.5	2.8	17.6		23.5	6.3	29.8	47.4
AG-TOU	4.4	45.9	11.2	61.5		68.0	26.5	94.6	156.0
TOU-PA-5	3.7	22.0	6.7	32.5		44.0	16.0	60.0	92.5
Total Ag.&Pump.	11.9	110.4	24.3	146.6		165.5	55.8	221.3	367.9
Total Street Lights	1.9	89.6	6.1	97.5		26.3	12.4	38.7	136.2
CVCCEN	474.0	0.470.0	040.0	4.504.0		E 227.0	4 270 0	0.704.0	44 000 0
SYSTEM	471.8	3,478.8	613.6	4,564.2		5,327.9	1,376.9	6,704.8	11,268.9

Direct Access Service Revenues Forecast October 1, 2009 Revenue Requirement (\$MM)

	Trans	Dist.	Other	Total Delivery	DACRS	Total Gen and Delivery
Total Residential	0.7	5.8	0.8	7.3	4.2	11.5
GS-1	0.4	3.0	0.5	3.8	1.5	5.3
TC-1	0.0	0.1	0.0	0.1	0.0	0.2
GS-2	4.1	32.6	8.8	45.5	6.3	51.8
TOU-GS-3	7.2	49.9	12.9	70.0	5.9	75.9
Total LSMP	11.7	85.6	22.1	119.4	13.7	133.2
TOU-8-Sec	9.0	47.6	15.2	71.9	7.9	79.8
TOU-8-Pri	7.0	33.8	12.2	53.1	5.9	58.9
TOU-8-Sub	10.7	13.8	20.8	45.3	10.7	56.0
Total Large Power	26.8	95.3	48.2	170.2	24.5	194.7
PA-1	0.0	0.1	0.0	0.2	0.1	0.2
PA-2	0.0	0.3	0.1	0.4	0.3	0.6
AG-TOU	0.1	1.1	0.5	1.6	1.5	3.1
TOU-PA-5	0.0	0.1	0.0	0.1	0.1	0.2
Total Ag.&Pump.	0.1	1.6	0.6	2.3	1.9	4.2
Total Street Lights	0.1	0.5	0.2	0.8	0.5	1.2
SYSTEM	39.4	188.8	71.9	300.1	44.8	344.8

Direct Access Rate Groups Forecast October 1, 2009 Rates (cents/kWh)

	Rates Effective December 2008	October 1, 2009 Proposed	Percent Change
Residential	8.77	9.41	7.3%
Lighting, Small and Medium Power			
GS-1	8.23	9.74	18.5%
TC-1	8.10	9.91	22.3%
GS-2	6.24	4.95	-20.7%
TOU-GS-3	6.43	4.78	-25.7%
Group Total	6.37	4.94	-22.4%
Large Power			
TOU-8-Sec	6.01	4.15	-30.9%
TOU-8-Pri	5.60	3.78	-32.5%
TOU-8-Sub	3.79	1.93	-49.0%
Group Total	4.88	3.05	-37.4%
A and a subtract to Dromania a			
Agricultural & Pumping	0.04	7.00	45.00/
PA-1	6.04	7.00	15.9%
PA-2	6.02	5.54	-7.9%
AG-TOU	4.62	4.88	5.7%
TOU-PA-5	6.55	5.99	-8.6%
Group Total	4.99	5.11	2.5%
Street & Area Lightingr	5.92	5.91	-0.2%
System Total	5.28	3.70	-29.9%

ATTACHMENT ONE REVISED FORECAST OF OCTOBER 1, 2009 AND ADJUSTED CONSOLIDATED REVENUE REQUIREMENTS

JUNE 2009 FORECAST OCTOBER 1, 2009 AND ADJUSTED CONSOLIDATED REVENUE REQUIREMENTS (\$000)

35,902 39,388 374,290 2,226 44,766 5,449 45,442 49,362 40,846 3,920 324,928 329,525 376,517 203,343 Adjusted Consolidated Revenue 5,324,840 1,383,515 11,627,336 18,863 367,729 471,759 45,899 6,708,356 4,918,980 9,886,483 11,646,199 3,676,256 357,338 1,740,854 Requirement Bundled Service 12,022,715 21,089 51,348 511,147 5,365,686 5,248,505 1,790,216 12,001,626 1,387,435 3,879,599 403,631 402,780 10,211,411 6,753,121 Retail Total 40,846 44,766 18,752 39,388 293,244 2,226 3,920 188,809 5,449 342,606 45,442 297,840 49,362 344,832 October 1, 2009 Revenue Requirement 11,268,945 471,759 18,863 383,515 4,545,299 9,509,228 6,704,783 191,456 45,899 357,338 11,250,082 1,740,854 5,321,267 3,478,847 Bundled Service 11,592,688 21,089 5,362,113 1,387,435 51,348 11,613,777 6,749,548 3,667,656 210,209 511,147 402,780 4,843,140 9,802,472 1,790,216 Total Retail **TOTAL REVENUE REQUIREMENT** Total SCE Delivery and Generation Total DWR Revenue Requirement Nuclear Decommissioning Public Purpose Programs Total SCE Generation **DWR Power Charge DWR Bond Charge** Total SCE and DWR **Transmission** Total Generation Distribution GENERATION **Total Delivery** DELIVERY PUCRF

from Distribution, \$3.6 million from SCE Generation), (2) the suspension of the CSI revenue requirement of \$111.2 million from Distribution removes the effect of the following reductions in SCE's authorized revenues in 2009: (1) The PBR refund of \$104.3 million (\$100.7 million Note: The \$409 million difference between forecast revenues for October 1, 2009 and the adjusted consolidated revenue requirement revenues, and (3) the refund of unspent CEC renewables monies of \$193.4 million from Public Purpose Programs revenues. ATTACHMENT TWO REVISED PROPOSED RATES EFFECTIVE OCTOBER 1, 2009

			Rates Ef	fective Decer	nber 2008	Pr	oposed Rat	es Effective O	ctober 1, 2009	
Note: Resi	idential rates based on seve	n cent Tier 3 - Tier 5								
differential	and baseline allocations se	t at 55% of average								
	usage by CEC climate zone provided in Paragraph 4.b.iii									Total Rate
to be imple	emented effective with rate of		Delivery	Generation	Total Rate		Delivery	Generation	Total Rate	Change
ERRA pro	ceeding.									
	Energy Charge- \$/kWh									
		Baseline - Summer - Winter	0.07217 0.07217	0.04861 0.04861	0.12078 0.12078		0.07901 0.07901	0.03907 0.03907	0.11808 0.11808	-2.24% -2.24%
	101% - 130%	of Baseline - Summer	0.07217	0.06794	0.14011		0.07901	0.05840	0.13741	-1.93%
	131% - 200%	- Winter of Baseline - Summer	0.07217 0.07217	0.06794 0.13559	0.14011 0.20776		0.07901 0.07901	0.05840 0.15753	0.13741 0.23654	-1.93% 13.85%
	131/6 - 200/6	- Winter	0.07217	0.13559	0.20776		0.07901	0.15753	0.23654	13.85%
	200% - 300%	of Baseline - Summer - Winter	0.07217 0.07217	0.17059 0.17059	0.24276 0.24276		0.07901 0.07901	0.19254 0.19254	0.27155 0.27155	11.86% 11.86%
		Over 300% of Baseline	0.07217	0.20559	0.27776		0.07901	0.22753	0.30654	10.36%
		- Winter	0.07217	0.20559	0.27776		0.07901	0.22753	0.30654	10.36%
	Basic Charge - \$/day									
		Single-Family Residence	0.029	0.000	0.029		0.029		0.029	0.00%
	Minimum Charge - \$/day	Multi-Family Residence	0.022	0.000	0.022		0.022		0.022	0.00%
	- '	Single Family Residence	0.059	0.000	0.059		0.059		0.059	0.00%
		Multi-Family Residence	0.044	0.000	0.044		0.044		0.044	0.00%
	Peak Time Rebate - \$kWh	n								
	Peak Time Rebate w/enabling technology - \$a	/kWh						(0.75) (1.25)	(0.75) (1.25)	
	g	-						(23)	(20)	
D-CARE	Energy Charge - \$/kWh									
	=9,9- +	Baseline - Summer	0.03672	0.04861	0.08533		0.04626	0.03907	0.08533	0.00%
	101% - 130%	- Winter of Baseline - Summer	0.03672 0.03874	0.04861 0.06794	0.08533 0.10668		0.04626 0.04828	0.03907 0.05840	0.08533 0.10668	0.00% 0.00%
		- Winter	0.03874	0.06794	0.10668		0.04828	0.05840	0.10668	0.00%
	131% - 200%	of Baseline - Summer - Winter	0.02301 0.02301	0.13559 0.13559	0.15860 0.15860		0.02553 0.02553	0.15753 0.15753	0.18306 0.18306	15.42% 15.42%
	200% - 300%	of Baseline - Summer	(0.01199)	0.17059	0.15860		(0.00947)	0.19254	0.18307	15.43%
		- Winter Over 300% of Baseline	(0.01199) (0.04699)	0.17059 0.20559	0.15860 0.15860		(0.00947) (0.04447)	0.19254 0.22753	0.18307 0.18306	15.43% 15.42%
		- Winter	(0.04699)	0.20559	0.15860		(0.04447)	0.22753	0.18306	15.42%
	Basic Charge - \$/day									
	basic onlarge - waay	Single-Family Residence	0.023	0.000	0.023		0.023		0.023	0.00%
	Minimum Charge - \$/day	Multi-Family Residence	0.017	0.000	0.017		0.017		0.017	0.00%
	wiiminum onarge - waay	Single Family Residence	0.047	0.000	0.047		0.047		0.047	0.00%
		Multi-Family Residence	0.034	0.000	0.034		0.034		0.034	0.00%
	Peak Time Rebate - \$kWh	n								
	Peak Time Rebate w/enabling technology - \$	/k\N/h						(0.75) (1.25)	(0.75) (1.25)	
	w/enabiling technology - 5/	/KVVII						(1.23)	(1.23)	
D-APS	Air Conditioning Cycling									
		summer season day								
		50% Cycling 67% Cycling	(0.05) (0.10)	0.00	(0.05) (0.10)		(0.04)		(0.04)	30.00% 27.00%
		100% Cycling	(0.10)	0.00	(0.10)		(0.36)		(0.07)	-98.89%
D-APS-E										
D-AFO-E	Air Conditioning Cycling									
	Credit - \$/ton/	summer season day 50% Cycling	(0.10)	0.00	(0.10)		(0.04)		(0.04)	60.00%
		67% Cycling	(0.20)	0.00	(0.20)		(80.0)		(0.08)	59.00%
		100% Cycling	(0.36)	0.00	(0.36)		(0.41)		(0.41)	-13.61%
DE										
	Discount - %		100.00				100.00		100.00	
D-FERA										
	Energy Charge- \$/kWh	Baseline - Summer	0.06947	0.04861	0.11808		0.07901	0.03907	0.11808	0.00%
		- Winter	0.06947	0.04861	0.11808		0.07901	0.03907	0.11808	0.00%
	101% - 130%	of Baseline - Summer	0.06947	0.06794	0.13741		0.07901	0.05840	0.13741	0.00%
	131% - 200%	- Winter of Baseline - Summer	0.06947 0.06947	0.06794 0.06794	0.13741 0.13741		0.07901 0.07901	0.05840 0.05840	0.13741 0.13741	0.00% 0.00%
		- Winter	0.06947	0.06794	0.13741		0.07901	0.05840	0.13741	0.00%
	200% - 300%	of Baseline - Summer - Winter	0.06947 0.06947	0.17059 0.17059	0.24006 0.24006		0.07901 0.07901	0.19254 0.19254	0.27155 0.27155	13.12% 13.12%
	•	Over 300% of Baseline	0.06947	0.20559	0.27506		0.07901	0.22753	0.30654	11.44%
		- Winter	0.06947	0.20559	0.27506		0.07901	0.22753	0.30654	11.44%

1

			Rates Ef	fective Decen	nber 2008	Proposed Rate	es Effective C	october 1, 2009	
	dential rates based on sever								
aggregate	and baseline allocations set usage by CEC climate zone	, assuming modification of							
	rovided in Paragraph 4.b.iii amented effective with rate c		Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Total Rate Change
	Basic Charge - \$/day								
	Minimum Charge \$1day	Single-Family Residence Multi-Family Residence	0.029 0.022	0.000	0.029 0.022	0.029 0.022		0.029 0.022	0.00% 0.00%
	Minimum Charge - \$/day	Single Family Residence Multi-Family Residence	0.059 0.044	0.000	0.059 0.044	0.059 0.044		0.059 0.044	0.00%
	Peak Time Rebate - \$kWh								
	Peak Time Rebate w/enabling technology - \$/						(0.75) (1.25)	(0.75) (1.25)	
DM									
	Diversity Adjustment - \$/ui Agricultural Employee Hou		0.100	0.000	0.100	0.170		0.170	70.00%
	Discount - 9		100.00		100.00	100.00		100.00	
DMS-1	Submeter Discount - \$/uni	it/day	(0.086)	0.000	(0.086)	(0.097)		(0.097)	-12.79%
	Diversity Adjustment - \$/ur		0.100	0.000	0.100	0.170		0.170	70.00%
	Basic Charge - \$/unit/day		0.029	0.000	0.029	0.022		0.022	-24.14%
	Minimum Average Rate - S	\$/kWh	0.03776	0.00000	0.03776	0.02020		0.02020	-46.50%
DMS-2	Submeter Discount - \$/uni	t/dav	(0.300)	0.000	(0.300)	(0.340)		(0.340)	-13.33%
	Diversity Adjustment - \$/ui		0.100	0.000	0.100	0.170		0.170	70.00%
	Basic Charge - \$/unit/day		0.029	0.000	0.029	0.022		0.022	-24.149
	Minimum Average Rate - S	\$/kWh	0.03776	0.00000	0.03776	0.02020		0.02020	-46.50%
DMS-3	Basic Charge Adjust - \$/ur	nit/day	0.029	0.000	0.029	0.029	0.000	0.029	0.00%
DS									
	Summer Season Premium Winter Season Discount -	\$/kWh/day	0.030 (0.030)	0.040 (0.040)	0.070 (0.070)	0.030 (0.030)	0.040 (0.040)	0.070 (0.070)	0.00% 0.00%
	California Alternate Rates Energy Disco		100.00		100.00	100.00		100.00	
TOU-D-1									
	Energy Charge - \$/kWh	mer Season - On-Peak	0.08694	0.26652	0.35346	0.07901	0.32802	0.40703	15.16%
	Gain.	Off-Peak	0.08694	0.09701	0.18395	0.07901	0.10143	0.18044	-1.91%
	W	inter Season - On-Peak Off-Peak	0.08694 0.08694	0.12392 0.08887	0.21086 0.17581	0.07901 0.07901	0.11184 0.08637	0.19085 0.16538	-9.49% -5.93%
	Basic Charge - \$/day S	ingle-Family Residence	0.029	0.000	0.029	0.029	0.000	0.029	0.00%
		Multi-Family Residence	0.022	0.000	0.022	0.022	0.000	0.022	0.00%
	Minimum Charge - \$/da	y Single Family Residence	0.059	0.000	0.059	0.059	0.000	0.059	0.00%
		Multi-Family Residence	0.044	0.000	0.044	0.044	0.000	0.044	0.00%
	Baseline Credit - \$/kWh California Alternate Rate			(0.04885)	(0.04885)		-0.04885	-0.04885	0.00%
	Energy Disc		100.00		100.00	100.000		100.00	0.00%
	Peak Time Rebate - \$kWh	1							
	Peak Time Rebate w/enabling technology - \$/	/kWh					(0.75) (1.25)	(0.75) (1.25)	
TOU-D-2									
	Energy Charge - \$/kWh Sum	mer Season - On-Peak	0.08694	0.20549	0.29243	0.07901	0.25719	0.33620	14.97%
		Off-Peak	0.08694	0.07422	0.16116	0.07901	0.07953	0.15854	-1.63%
	W	inter Season - On-Peak Off-Peak	0.08694 0.08694	0.09506 0.06792	0.18200 0.15486	0.07901 0.07901	0.08769 0.06772	0.16670 0.14673	-8.41% -5.25%
	Customer Charge - \$/da	ay	0.230	0.000	0.230	0.230	0.000	0.230	0.00%
	California Alternate Rate Energy Disc		100.00		100.00	100.000		100.00	0.00%
	Peak Time Rebate - \$kWh								
	Peak Time Rebate w/ena						(0.75)	(0.75)	
							(1.25)	(1.25)	

Note: Residential rates based on seven cent Tier 3 - Tier	5								
differential and baseline allocations set at 55% of average	•								
aggregate usage by CEC climate zone, assuming modific									
AB1X as provided in Paragraph 4.b.iii and 4.b.v. CIA adju								Total Rate	
to be implemented effective with rate changes made in 20	10 for	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Change	
TOU-D-T									
Energy Charge - \$/kWh									
Summer Season									
Baseline (BL) - O	n-Peak				0.07901	0.12120	0.20021		
101% - 130% of BL - O	n-Peak				0.07901	0.12120	0.20021		
131% - 200% of BL - O	n-Peak				0.07901	0.46845	0.54746		
200% - 300% of BL - O	n-Peak				0.07901	0.46845	0.54746		
Over 300% of BL - O	n-Peak				0.07901	0.46845	0.54746		
Baseline (BL) - O	ff-Peak				0.07901	0.03557	0.11458		
101% - 130% of BL - O					0.07901	0.03557	0.11458		
131% - 200% of BL - O	ff-Peak				0.07901	0.15573	0.23474		
200% - 300% of BL - O	ff-Peak				0.07901	0.15573	0.23474		
Over 300% of BL - O					0.07901	0.15573	0.23474		
Winter Season									
Baseline (BL) - O	n-Peak				0.07901	0.03917	0.11818		
101% - 130% of BL - O					0.07901	0.03917	0.11818		
131% - 200% of BL - O					0.07901	0.16497	0.24398		
200% - 300% of BL - O					0.07901	0.16497	0.24398		
Over 300% of BL - O					0.07901	0.16497	0.24398		
Over 300 // 61 BE - 0	II-I Cak				0.07 50 1	0.10437	0.24000		
Baseline (BL) - O	ff-Pook				0.07901	0.02935	0.10836		
101% - 130% of BL - O					0.07901	0.02935	0.10836		
131% - 200% of BL - O					0.07901	0.13394	0.10030		
200% - 300% of BL - O					0.07901	0.13394	0.21295		
Over 300% of BL - O					0.07901	0.13394			
Over 300% of BL - O	п-Реак				0.07901	0.13394	0.21295		
Basic Charge - \$/day									
Single-Family Re	cidonco				0.029	0.000	0.029		
					0.023		0.023		
Multi-Family Re	siderice				0.022	0.000	0.022		
Minimum Charge - \$/day	-:				0.059	0.000	0.059		
Single Family Re						0.000			
Multi-Family Re	sidence				0.044	0.000	0.044		
California Alternate Rates for					400.00	0.000	400.00		
Energy Discount - %					100.00	0.000	100.00		
Peak Time Rebate - \$kWh									
•						(0.75)	(0.75)		
Peak Time Rebate						(0.75)	(0.75)		
w/enabling technology - \$/kWh						(1.25)	(1.25)		
TOU 51/4									
TOU-EV-1									
Energy Charge - \$/kWh		0.005	0.4445-	0.007	0.405	0.475	0.0045	40.5551	
Summer Season - O		0.09599	0.14193	0.23792	0.10860	0.17571	0.28431	19.50%	
O	ff-Peak	0.09599	0.06121	0.15720	0.05112	0.05369	0.10481	-33.33%	
ue		0.005		0.470	0.445	0.0005-	0.000:-	40.55**	
Winter Season - O		0.09599	0.08367	0.17966	0.11601	0.09339	0.20940	16.55%	
O	ff-Peak	0.09599	0.06398	0.15997	0.05112	0.05310	0.10422	-34.85%	

Proposed Rates Effective October 1, 2009

			Rates En	ective Decer	nber 2008		Proposed Rat	I Effective C	october 1, 2008	
Neter Desi	dential rates based on sever	Ti 2 Ti 5								
	and baseline allocations set									
	usage by CEC climate zone									
	rovided in Paragraph 4.b.iii a									Total Rate
	emented effective with rate of		Delivery	Generation	Total Rate		Delivery	Generation	Total Rate	Change
TOU-TEV	Sinched encouve with rate of	nanges made in 2010 for	Donvery	OCHCIALION	Total Nate	1	Bontory	Concration	Total Nate	Onlango
.00 .21	Energy Charge - \$/kWh									
		.on								
	Summer Seas						0.00470	0.12089	0.20562	
		Baseline (BL) - On-Peak					0.08473			
		% - 130% of BL - On-Peak					0.08473	0.12089	0.20562	
		% - 200% of BL - On-Peak					0.08473	0.49352	0.57825	
		% - 300% of BL - On-Peak					0.08473	0.49352	0.57825	
	Ov	er 300% of BL - On-Peak					0.08473	0.49352	0.57825	
		Baseline (BL) - Off-Peak					0.08473	0.03610	0.12083	
	1019	6 - 130% of BL - Off-Peak					0.08473	0.03610	0.12083	
	1319	6 - 200% of BL - Off-Peak					0.08473	0.16162	0.24635	
		% - 300% of BL - Off-Peak					0.08473		0.24635	
		ver 300% of BL - Off-Peak					0.08473		0.24635	
	Roca	line (BL) - Super Off-Peak					0.05112	0.03957	0.09069	
		1% of BL - Super Off-Peak					0.05112		0.09069	
	101/6-130	1% of BL - Super Off Dools					0.05112		0.09069	
		% of BL - Super Off-Peak								
		% of BL - Super Off-Peak					0.05112			
	Over 300	% of BL - Super Off-Peak					0.05112	0.10502	0.15614	
	Winter Season									
		Baseline (BL) - On-Peak					0.08473	0.03790	0.12263	
		% - 130% of BL - On-Peak					0.08473	0.03790	0.12263	
		% - 200% of BL - On-Peak					0.08473	0.17310	0.25783	
	2009	% - 300% of BL - On-Peak					0.08473	0.17310	0.25783	
	Ov	er 300% of BL - On-Peak					0.08473	0.17310	0.25783	
		Baseline (BL) - Off-Peak					0.08473		0.11280	
	1019	6 - 130% of BL - Off-Peak					0.08473	0.02807	0.11280	
	1319	6 - 200% of BL - Off-Peak					0.08473	0.14382	0.22855	
	200%	6 - 300% of BL - Off-Peak					0.08473	0.14382	0.22855	
		ver 300% of BL - Off-Peak					0.08473	0.14382	0.22855	
	Base	line (BL) - Super Off-Peak					0.05112	0.04023	0.09135	
		% of BL - Super Off-Peak					0.05112		0.09135	
		% of BL - Super Off-Peak					0.05112		0.15851	
	200% 300	% of BL - Super Off-Peak					0.05112		0.15851	
	200% - 300 Over 200	1% Of BL - Super Off Book					0.05112		0.15851	
	Over 300	% of BL - Super Off-Peak					0.05112	0.10739	0.13631	
	Basic Charge - \$/day									
	basic Charge - \$/day	Single-Family Residence					0.029	0.000	0.029	
		Multi-Family Residence					0.022	0.000	0.022	
	Minimum Charge - \$/day	0								
		Single Family Residence					0.059	0.000	0.059	
		Multi-Family Residence					0.044	0.000	0.044	
	California Alternate Rates									
	Energy Discou	ınt - %					100.00	0.00	100.00	
	Peak Time Rebate - \$kWh	ı								
	Peak Time Rebate							(0.75)	(0.75)	
	w/enabling technology - \$/	kWh						(1.25)	(1.25)	
GS-1										
	Energy Charge - \$/kWh									
		Summer	0.04157	0.10789	0.14946		0.05044	0.12875	0.17919	19.89%
		Winter	0.04157	0.10450	0.14607		0.05044	0.07875	0.12919	-11.56%
	Customer Charge - \$/day		0.565	0.000	0.565		0.674		0.674	19.29%
	Three Phase Service - \$/d	ay	0.138	0.000	0.138		0.030		0.030	-78.26%
	Voltage Discount, Energy -									
		From 2 kV to 50 kV	(0.00026)	(0.00227)	(0.00253)		(0.00047)	(0.00217)	(0.00264)	-4.50%
		From 51 kV to 219 kV	(0.00856)	(0.00494)	(0.01350)		(0.01474)	(0.00484)	(0.01958)	-45.04%
		220 kV and above					(0.01492)	(0.00490)	(0.01982)	
	California Alternate Rates									
	Energy Discou	unt - %	100.00	0.00	100.00		100.00		100.00	0.00%

Rates Effective December 2008

	Rates Eff	fective Decen	nber 2008	Proposed Ra	tes Effective C	october 1, 2009	
Note: Residential rates based on seven cent Tier 3 - Tier 5 differential and baseline allocations set at 55% of average aggregate usage by CEC climate zone, assuming modification of ABTX as provided in Paragraph 4.b.ii and 4.b.v. CIA adjustment							Total Rate
to be implemented effective with rate changes made in 2010 for	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Change
GS-2 (Non TOU Option)							
Energy Charge - \$/kWh							
Summer	0.01613	0.06929	0.08542	0.01309		0.08802	3.049
Winter	0.01613	0.06176	0.07789	0.01309	0.06126	0.07435	-4.54%
Summer Time Related Demand Charge - \$/kW	0.00	18.62	18.62	0.00	19.86	19.86	6.66%
Voltage Discount, Time-Related Demand - \$/kW							
From 2 kV to 50 kV From 51 kV to 219 kV	0.00	(0.40) (1.04)	(0.40) (1.04)	0.00	(0.56) (1.55)	(0.56) (1.55)	-40.009 -49.049
220 kV and above	0.00	(1.04)	(1.04)	0.00	(1.57)	(1.57)	-13.04
GS-2 (TOU Option A) Energy Charge - \$/kWh							
Summer Season							
On-Peak	0.01613	0.21879	0.23492	0.01309		0.33403	42.199
Mid-peak	0.01613	0.17469	0.19082	0.01309		0.13809	-27.639
Off-Peak Winter Season	0.01613	0.04756	0.06369	0.01309	0.05162	0.06471	1.609
Mid-peak	0.01613	0.07556	0.09169	0.01309	0.07293	0.08602	-6.18
Off-Peak	0.01613	0.05111	0.06724	0.01309	0.04888	0.06197	-7.849
GS-2 (TOU Option B) Energy Charge - \$/kWh							
Summer Season							
On-Peak	0.01613	0.09106	0.10719	0.01309		0.13272	23.829
Mid-peak Off-Peak	0.01613 0.01613	0.07224 0.04756	0.08837 0.06369	0.01309 0.01309		0.08879 0.06471	0.48° 1.60°
Winter Season	0.01013	0.04730	0.00309	0.01308	0.03102	0.00471	1.00
Mid-peak	0.01613	0.07556	0.09169	0.01309		0.08602	-6.189
Off-Peak	0.01613	0.05111	0.06724	0.01309	0.04888	0.06197	-7.849
Time Related Demand Charge - \$/kW	0.00	18.62	18.62	0.00	0.00	0.00	
Summer Season							
On-Peak Mid-Peak				0.00	17.41 5.32	17.41 5.32	
Wild-reak				0.00	5.52	5.52	
Voltage Discount, Time-Related Demand - \$/kW							
From 2 kV to 50 kV	0.00	(0.40)	(0.40)	0.00		(0.56)	-40.009
From 51 kV to 219 kV 220 kV and above	0.00	(1.04)	(1.04)	0.00	(1.55) (1.57)	(1.55) (1.57)	-49.049
					()	()	
GS-2 (All Options)	04.05	0.00	04.05	400.05		400.05	00.000
Customer Charge - \$/month	94.65	0.00	94.65	123.25		123.25	30.229
Facilities Related Demand Charge - \$/kW	9.54	0.00	9.54	11.15		11.15	16.889
Single Phase Service - \$/month	(29.42)	0.00	(29.42)	(10.97)	(10.97)	62.719
Voltage Discount, Facilities Related Demand - \$/kW							
From 2 kV to 50 kV	(0.19)	0.00	(0.19)	(0.14		(0.14)	26.32
From 51 kV to 219 kV 220 kV and above	(6.24)	0.00	(6.24)	(4.28 (9.08		(4.28) (9.08)	31.419
Voltage Discount, Energy - \$/kWh				(0.00)	,	(0.00)	
From 2 kV to 50 kV	0.00000	(0.00199)	(0.00199)	0.00000		(0.00140)	29.65
From 51 kV to 219 kV 220 kV and above	0.00000	(0.00433)	(0.00433)	0.00000		(0.00311) (0.00315)	28.189
220 KV and above				0.00000	(0.00313)	(0.00313)	
CARE Energy Discount - %	100.00%		100.00%	100.00%		100.00%	
Bill Limiter (GS-1 to GS-2) - %	20.89%	79.11%	100.00%	20.89%	79.11%	100.00%	
TOU Option Meter Charge - \$/month TOU-RTEM	158.83	0.00	158.83	86.55		86.55	-45.519
TOU-RIEM	158.83	0.00	156.63	86.55		80.55	-45.51%

			Rates Et	fective Dece	mber 2008	Proposed Rate	es Effective (October 1, 2009	
Note: Besidential r	rates based on seven o	ant Tion 2 Tion 5	ridio E		1001 2000	Topocou rial		1, 200	
differential and bas	seline allocations set at	55% of average							
AB1X as provided	in Paragraph 4.b.iii and	ssuming modification of d 4.b.v. CIA adjustment nges made in 2010 for	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Total Rate Change
GS-2 (TOU Optio	on R) gy Charge - \$/kWh								
2.1019	gy charge thirm	Summer Season							
		On-Peak Mid-peak				0.03211 0.03211	0.32094 0.12500		
		Off-Peak				0.03211	0.05162		
		Winter Season				0.00044	0.07000	0.40504	
		Mid-peak Off-Peak				0.03211 0.03211	0.07293 0.04888		
Custo	omer Charge - \$/mon	th				123.25	0.00	123.25	
Facilit	ties Related Demand	Charge - \$/kW				5.58	0.00	5.58	
Single	e Phase Service - \$/r	nonth				(10.97)	0.00	(10.97)	
Voltag	ge Discount, Facilitie	s Related Demand - \$/kW							
		From 2 kV to 50 kV				-0.07			
		From 51 kV to 219 kV 220 kV and above				-2.14 -3.51	0.00		
Voltag	ge Discount, Energy	- \$/kWh From 2 kV to 50 kV				0.00000	(0.00140)	(0.00140)	
		From 51 kV to 219 kV 220 kV and above				0.00000 0.00000	(0.00311)	(0.00311)	
CARE	E Energy Discount - 9	%				100.00%	0.00%	100.00%	
Bill Li	miter (GS-1 to GS-2)	- %				20.89%	79.11%	100.00%	
TOU	Option Meter Charge								
		TOU-RTEM				86.55	0.00	86.55	
	les: GS-1 and TOU-GS anditioning Cycling Cre	3-1) dit - \$/ton/summer season day							
74. 00	manaorining Oyoning Oro	30% Cycling	(0.014)	0.000	(0.014)	(0.053)	0.000	(0.053)	-278.57%
		40% Cycling	(0.042)	0.000	(0.042)	(0.069)		(0.069)	-64.29%
		50% Cycling 100% Cycling	(0.070) (0.200)	0.000	(0.070) (0.200)	(0.091) (0.370)		(0.091) (0.370)	-30.00% -85.00%
		100 /u Oyelling	(0.200)	0.000	(0.200)	(0.570)	0.000	(0.570)	-00.0070
	les: GS-2, TOU-GS-3,		41-						
AII Co	onalitioning Cycling Cred	dit - \$/ton/summer season mon 30% Cycling	un (0.42)	0.00	(0.42)	(1.62)	0.00	(1.62)	-285.71%
		40% Cycling	(1.25)	0.00	(1.25)	(2.11)		(2.11)	-68.80%
		50% Cycling	(2.10)	0.00	(2.10)	(2.77)		(2.77)	-31.90%
		100% Cycling	(6.00)	0.00	(6.00)	(11.25)	0.00	(11.25)	-87.50%
GS-APS-E (Sched	dules: GS-1 and TOU-	GS-1)							
Air Co	onditioning Cycling Cre	dit - \$/ton/summer season day							
		30% Cycling	(0.028)	0.000	(0.028)	(0.064)		(0.064)	-128.57%
		40% Cycling 50% Cycling	(0.084) (0.140)	0.000	(0.084) (0.140)	(0.084) (0.106)		(0.084) (0.106)	0.00% 24.29%
		100% Cycling	(0.400)	0.000	(0.400)	(0.416)		(0.416)	-4.00%
GS ABS E (School	dules: GS-2, TOU-GS-	3 or TOU-9)							
		dit - \$/ton/summer season mon	th						
	0,0	30% Cycling	(0.84)	0.00	(0.84)	(1.93)	0.00	(1.93)	-129.76%
		40% Cycling	(2.50)	0.00	(2.50)	(2.55)		(2.55)	-2.00%
		50% Cycling 100% Cycling	(4.20) (12.00)	0.00	(4.20) (12.00)	(3.21) (12.64)		(3.21) (12.64)	23.57% -5.33%
		10070 Gydinig	(12.00)	0.00	(12.00)	(12.01)	0.00	(12.01)	0.007
RTP-2	U Chargo C/UMh								
Energy	y Charge - \$/kWh	Below 2 kV	0.01481	Variable*	Variable*	0.01225	Variable*	Variable*	
		From 2 kV to 50 kV		Variable*	Variable*		Variable*	Variable*	
0 1	01 01 11	above 50 kV	0.01289	Variable*	Variable*	0.01116	Variable*	Variable*	
Custo	mer Charge - \$/month	Below 2 kV	458.04	0.00	458.04	530.50	0.00	530.50	15.82%
		From 2 kV to 50 kV	275.69	0.00	275.69	284.75	0.00	284.75	3.29%
_		above 50 kV	2,427.22	0.00	2,427.22	2,183.50	0.00	2,183.50	-10.04%
Faciliti	ies Related Demand C	harge - \$/kW Below 2 kV	10.77	0.00	10.77	11.60	0.00	11.60	7.71%
		From 2 kV to 50 kV	10.77	0.00	10.77	10.98	0.00	10.98	7.71%
		above 50 kV	2.80	0.00	2.80	4.05	0.00	4.05	44.64%
	Voltage Disc	count, Hourly Rates - %							
		From 2 kV to 50 kV	0.00%	0.00%		0.00% 0.00%	0.00%		
	-				0.00%	0.00%			
	-	50 kV, but below 220 kV at 220 kV	0.00% 0.00%						
V	above 5	50 kV, but below 220 kV	0.00%	-1.21%		0.00%	-1.21%		
	above 5 /oltage Discount, Facili	50 kV, but below 220 kV at 220 kV ty-Related Demand - % at 220 kV							
	above 5	50 kV, but below 220 kV at 220 kV ty-Related Demand - % at 220 kV /kVA	0.00%	-1.21%	-1.21%	0.00%		-1.21% 100.00%	60.00%
	above 5 /oltage Discount, Facili	50 kV, but below 220 kV at 220 kV ty-Related Demand - % at 220 kV	0.00%			0.00%		-1.21%	60.00% 50.00%

*See RTP Schedules for RTP-2 & PA-RTP

Note: Residential rates based on seven cent Tier 3 - Tier 5 differential and baseline allocations set at 55% of average aggregate usage by CEC climate zone, assuming modification of AB1X as provided in Paragraph 4.b.ii and 4.b.v. CIA adjustment to be implemented effective with rate changes made in 2010 for TOU-BIP Option - \$/kW (Applicable: Average kW demand) Option A BIP Option Credit (\$/kW) Below 2 kV - Summer Average On Peak Summer Average Mid - Peak Excess Energy Charge - \$/kWh 10.21374 0.00000 10.21374 13.90079 From 2 kV to 50 kV - Summer Average Mid - Peak Summer Average Mid - Peak Summer Average Mid - Peak Excess Energy Charge - \$/kWh 10.21374 0.00000 10.21374 13.90079		
differential and baseline allocations set at 55% of average aggregate usage by CEC climate zone, assuming modification of AB1X as provided in Paragraph 4.b.ii and 4.bv. ClA adjustment to be implemented effective with rate changes made in 2010 for Delivery Generation Total Rate Delivery Generation TOU-BIP Option - \$/kW (Applicable: Average kW demand) Option A BIP Option Credit (\$/kW) Below 2 kV - Summer Average On Peak (17.89) 0.00 (17.89) (21.11) Summer Average Mid - Peak (5.50) 0.00 (5.50) (6.45) Winter Average Mid - Peak (2.02) 0.00 (2.02) (13.2) Excess Energy Charge - \$/kWh 10.21374 0.00000 10.21374 13.90079 From 2 kV to 50 kV - Summer Average On Peak (17.48) 0.00 (17.48) (20.74)	(21.11) (6.45) (1.32)	
aggregate usage by CEC climate zone, assuming modification of AB1X as provided in Paragraph 4.b.iii and 4.b.v. CIA adjustment to be implemented effective with rate changes made in 2010 for Delivery Generation Total Rate Delivery Generation TOU-BIP Option - \$/kW (Applicable: Average kW demand) Option A BIP Option Credit (\$/kW) 8 0.00 (17.89) (21.11) Summer Average Mid - Peak (5.50) 0.00 (5.50) (6.45) Winter Average Mid - Peak (2.02) 0.00 (2.02) (13.2) Excess Energy Charge - \$/kWh 10.21374 0.00000 10.21374 13.90079 From 2 kV to 50 kV - Summer Average On Peak (17.48) 0.00 (17.48) (20.74)	(21.11) (6.45) (1.32)	To C
Delivery Generation Total Rate Delivery Generation Generation Delivery Generation Delivery Generation Delivery Generation Delivery Generation Gener	(21.11) (6.45) (1.32)	
TOU-BIP Option - \$/kW (Applicable: Average kW demand) Option A BIP Option Credit (\$/kW) Below 2 kV - Summer Average On Peak (5.50) 0.00 (17.89) (21.11) Summer Average Mid - Peak (5.50) 0.00 (5.50) (6.45) Winter Average Mid - Peak (2.02) 0.00 (2.02) (1.32) Excess Energy Charge - \$/kWh 10.21374 0.00000 10.21374 13.90079 From 2 kV to 50 kV - Summer Average On Peak (17.48) 0.00 (17.48) (20.74)	(21.11) (6.45) (1.32)	<u> </u>
Option A BIP Option Credit (\$/KW) (17.89) 0.00 (17.89) (21.11) Below 2 kV - Summer Average Mid - Peak (5.50) 0.00 (5.50) (6.45) Winter Average Mid - Peak (2.02) 0.00 (2.02) (1.32) Excess Energy Charge - \$/kWh 10.21374 0.0000 10.21374 13.90079 From 2 kV to 50 kV - Summer Average On Peak (17.48) 0.00 (17.48) (20.74)	(6.45) (1.32)	
Option A BIP Option Credit (\$/KW) (17.89) 0.00 (17.89) (21.11) Below 2 kV - Summer Average Mid - Peak (5.50) 0.00 (5.50) (6.45) Winter Average Mid - Peak (2.02) 0.00 (2.02) (1.32) Excess Energy Charge - \$/kWh 10.21374 0.0000 10.21374 13.90079 From 2 kV to 50 kV - Summer Average On Peak (17.48) 0.00 (17.48) (20.74)	(6.45) (1.32)	
Below 2 kV - Summer Average On Peak (17.89) 0.00 (17.89) (21.11) Summer Average Mid - Peak (5.50) 0.00 (5.50) (6.45) Winter Average Mid - Peak (2.02) 0.00 (2.02) (1.32) Excess Energy Charge - \$\frac{1}{2}\text{Wh} 10.21374 0.00000 10.21374 13.90079} From 2 kV to 50 kV - Summer Average On Peak (17.48) 0.00 (17.48) (20.74)	(6.45) (1.32)	
Summer Average Mid - Peak (5.50) 0.00 (5.50) (6.45) Winter Average Mid - Peak (2.02) 0.00 (2.02) (1.32) Excess Energy Charge - \$/kWh 10.21374 0.00000 10.21374 13.90079 From 2 kV to 50 kV - Summer Average On Peak (17.48) 0.00 (17.48) (20.74)	(6.45) (1.32)	
Winter Average Mid - Peak (2.02) 0.00 (2.02) (1.32) Excess Energy Charge - \$/kWh 10.21374 0.00000 10.21374 13.90079 From 2 kV to 50 kV - Summer Average On Peak (17.48) 0.00 (17.48) (20.74)	(1.32)	
Excess Energy Charge - \$/kWh 10.21374 0.00000 10.21374 13.90079 From 2 kV to 50 kV - Summer Average On Peak (17.48) 0.00 (17.48) (20.74)		
From 2 kV to 50 kV - Summer Average On Peak (17.48) 0.00 (17.48) (20.74)	13.90079	
	(20.74)	
Summer Average Mid - Peak (5.40) 0.00 (5.40) (6.12)	(6.12)	
Winter Average Mid - Peak (1.98) 0.00 (1.98) (1.28)	(1.28)	
Excess Energy Charge - \$/kWh 9.99551 0.00000 9.99551 13.61036	13.61036	
	(40.50)	
above 50 kV - Summer Average On Peak (16.84) 0.00 (16.84) (19.56) Summer Average Mid - Peak (5.22) 0.00 (5.22) (5.56)	(19.56) (5.56)	
Winter Average Mid - Peak (1.90) 0.00 (1.90) (1.13)	(1.13)	
Excess Energy Charge - \$/kWh 9.63234 0.00000 9.63234 13.09434	13.09434	
Option B		
BIP Option Credit (\$/KW)		
Below 2 kV - Summer Average On Peak (16.45) 0.00 (16.45) (19.74) Summer Average Mid - Peak (5.02) 0.00 (5.02) (6.02)	(19.74)	
Summer Average Mid - Peak (5.02) 0.00 (5.02) (6.02) Winter Average Mid - Peak (1.93) 0.00 (1.93) (1.22)	(6.02) (1.22)	
Excess Energy Charge - \$/kWh 10.21374 0.0000 10.21374 12.96442	12.96442	
Execute Energy Change Commission Control Contr	12.00112	
From 2 kV to 50 kV - Summer Average On Peak (16.10) 0.00 (16.10) (19.31)	(19.31)	
Summer Average Mid - Peak (4.92) 0.00 (4.92) (5.70)	(5.70)	
Winter Average Mid - Peak (1.89) 0.00 (1.89) (1.19)	(1.19)	
Excess Energy Charge - \$/kWh 9.99551 0.00000 9.99551 12.69398	12.69398	
above 50 kV - Summer Average On Peak (15.52) 0.00 (15.52) (18.34)	(18.34)	
Summer Average Gif Feak (15.52) (15.54) Summer Average Mid - Peak (4.74) 0.00 (4.74) (5.21)	(5.21)	
Winter Average Mid - Peak (1.82) 0.00 (1.82) (1.05)	(1.05)	
Excess Energy Charge - \$/kWh 9.63234 0.00000 9.63234 12.21347	12.21347	
TOU-EV-3		
Energy Charge - \$/kWh Summer Season On-Peak 0.05429 0.19715 0.25144 0.04757 0.22104	0.26861	
Off-Peak 0.05429 0.07532 0.12961 0.04757 0.05634		
Winter Season On-Peak 0.05429 0.10409 0.15838 0.04757 0.10094	0.14851	
Off-Peak 0.05429 0.07481 0.12910 0.04757 0.05187	0.09944	
0.1.01.01.01.	0.074	
Customer Charge - \$/day 0.565 0.000 0.565 0.674	0.674	
	0.674	
TOU-EV-4	0.674	
OU-EV-4 Energy Charge - \$/kWh	0.25498	
TOU-EV-4 Energy Charge - \$/kWh Summer Season On-Peak 0.01613 0.12986 0.14599 0.01309 0.24189 Off-Peak 0.01613 0.04875 0.06488 0.01309 0.05247	0.25498 0.06556	
COU-EV-4 Energy Charge - \$/kWh Summer Season On-Peak Off-Peak 0.01613 0.12986 0.14599 0.01309 0.24189 0.01692 0.06488 0.01309 0.05247 Winter Season On-Peak 0.01613 0.06792 0.08405 0.01309 0.11064	0.25498 0.06556 0.12373	
TOU-EV-4 Energy Charge - \$/kWh Summer Season On-Peak 0.01613 0.12986 0.14599 0.01309 0.24189 Off-Peak 0.01613 0.04875 0.06488 0.01309 0.05247	0.25498 0.06556 0.12373	
TOU-EV-4 Energy Charge - \$/kWh	0.25498 0.06556 0.12373 0.06124	
TOU-EV-4 Energy Charge - \$/kWh Summer Season On-Peak Off-Peak 0.01613 0.12986 0.14599 0.01309 0.24189 0.01613 0.04875 0.06488 0.01309 0.05247 Winter Season On-Peak Off-Peak 0.01613 0.06792 0.08405 0.01309 0.11064 0.01613 0.04842 0.06455 0.01309 0.04815 Customer Charge - \$/meter/month 94.65 0.00 94.65 123.25	0.25498 0.06556 0.12373	
FOU-EV-4 Energy Charge - \$/kWh Summer Season On-Peak Off-Peak 0.01613 0.12986 0.14599 0.01309 0.24189 0.01693 0.04875 0.06488 0.01309 0.05247 Winter Season On-Peak 0.01613 0.04875 0.08405 0.01309 0.11064 Off-Peak 0.01613 0.04842 0.06455 0.01309 0.04815 Customer Charge - \$/meter/month 94.65 0.00 94.65 123.25 Facilities Related	0.25498 0.06556 0.12373 0.06124	
FOU-EV-4 Energy Charge - \$/kWh Summer Season On-Peak Off-Peak 0.01613 0.12986 0.14599 0.01309 0.24189 0.01693 0.04875 0.06488 0.01309 0.05247 Winter Season On-Peak 0.01613 0.04875 0.08405 0.01309 0.11064 Off-Peak 0.01613 0.04842 0.06455 0.01309 0.04815 Customer Charge - \$/meter/month 94.65 0.00 94.65 123.25 Facilities Related	0.25498 0.06556 0.12373 0.06124 123.25	
TOU-EV-4 Energy Charge - \$/kWh Summer Season On-Peak 0.01613 0.12986 0.14599 0.01309 0.24189 Off-Peak 0.01613 0.04875 0.06488 0.01309 0.05247 Winter Season On-Peak 0.01613 0.06792 0.08405 0.01309 0.11064 Off-Peak 0.01613 0.04842 0.06455 0.01309 0.04815 Customer Charge - \$/meter/month 94.65 0.00 94.65 123.25 Facilities Related Demand Charge - \$/kW 9.54 0.00 9.54 11.15	0.25498 0.06556 0.12373 0.06124 123.25 11.15	
Four-EV-4 Energy Charge - \$/kWh Summer Season On-Peak Off-Peak Off-Peak O.01613 O.04875 O.06488 O.01309 O.05247 Winter Season On-Peak Off-Peak O.01613 O.04875 O.06488 O.01309 O.05247 Winter Season On-Peak Off-Peak O.01613 O.06792 O.08405 O.01309 O.01094 O.04815 Customer Charge - \$/meter/month 94.65 O.00 94.65 123.25 Facilities Related Demand Charge - \$/kW 9.54 O.00 9.54 11.15 Time Related Demand Charge - \$/kW 0.00 18.62 18.62 O.00 19.86	0.25498 0.06556 0.12373 0.06124 123.25 11.15	
POU-EV-4 Energy Charge - \$/kWh	0.25498 0.06556 0.12373 0.06124 123.25 11.15	
OU-EV-4 Energy Charge - \$/kWh Summer Season On-Peak Off-Peak Off-Peak O.01613 0.12986 0.04875 0.06488 0.01309 0.05247 Winter Season On-Peak Off-Peak 0.01613 0.06792 0.08405 0.01309 0.11064 0.01613 0.06792 0.08405 0.01309 0.04815 Customer Charge - \$/meter/month 94.65 0.00 94.65 123.25 Facilities Related Demand Charge - \$/kW 9.54 0.00 9.54 11.15 Time Related Demand Charge - \$/kW 0.00 18.62 18.62 0.00 19.86 Voltage Discount, Facilities Related Demand - \$/kW From 2 kV to 50 kV 0.19) 0.00 0.19 0.14599 0.01309 0.24189 0.01309 0.04815 0.01309 0.04815 0.01309 0.04815	0.25498 0.06556 0.12373 0.06124 123.25 11.15 19.86	
OU-EV-4 Energy Charge - \$/kWh	0.25498 0.06556 0.12373 0.06124 123.25 11.15 19.86 (0.14) (4.28)	
POU-EV-4 Energy Charge - \$/kWh	0.25498 0.06556 0.12373 0.06124 123.25 11.15 19.86 (0.14) (4.28)	
POU-EV-4 Energy Charge - \$/kWh	0.25498 0.06556 0.12373 0.06124 123.25 11.15 19.86 (0.14) (4.28) (9.08)	
COU-EV-4 Energy Charge - \$/kWh Summer Season On-Peak 0.01613 0.12986 0.14599 0.01309 0.24188 0.01699 0.05247	0.25498 0.06556 0.12373 0.06124 123.25 11.15 19.86 (0.14) (4.28) (9.08)	
Form 2 kV to 50 kV Voltage Discount, Facilities Related Demand - \$/kW Voltage Discount, Time-Related Demand - \$/kW From 51 kV to 219 kV From 51 kV to 219 kV From 51 kV to 219 kV From 51 kV to 219 kV From 51 kV to 219 kV From 51 kV to 219 kV From 51 kV to 219 kV Energy Charge - \$/kWh Summer Season On-Peak 0.01613 0.04842 0.06488 0.01309 0.05247 0.004875 0.06488 0.01309 0.05247 0.006485 0.01309 0.014064 0.006455 0.01309 0.04815 0.01409 0.04845 0.004455 0.01309 0.04815 0.01409 0.04455 0.01309 0.04815 0.01409 0.04455 0.01309 0.04815 0.01409 0.04455 0.01309 0.04815 0.01409 0.04455 0.01309 0.01404 0.01613 0.04842 0.06455 0.01309 0.04815 0.01613 0.04842 0.004455 0.01613 0.04845 0.004455 0.0109 0.04455 0.01309 0.04815 0.0109 0.04655 0.01309 0.04815 0.0109 0.04655 0.01309 0.04815 0.0109 0.04655 0.01309 0.04815 0.0109 0.04655 0.01309 0.04815 0.0109 0.04655 0.01309 0.0149 0.0109 0.0199 0.0149 0.006 0.0199 0.0149 0.006 0.01855 0.01309 0.006 0.0199 0.0149 0.006 0.0199 0.0149 0.006 0.01855 0.01309 0.006 0.0199 0.0149 0.006 0.01855 0.01309 0.006 0.0199 0.0149 0.006 0.01855 0.01309 0.006 0.0199 0.0149 0.006 0.01855 0.01309 0.006 0.0199 0.0149 0.006 0.01855 0.01309 0.006 0.0199 0.0149 0.006 0.01855 0.01309 0.006 0.01856 0.01309 0.006 0.0199 0.0149 0.006 0.01856 0.0149	0.25498 0.06556 0.12373 0.06124 123.25 11.15 19.86 (0.14) (4.28) (9.08)	
Four Style Demand Charge - \$/kW	0.25498 0.06556 0.12373 0.06124 123.25 11.15 19.86 (0.14) (4.28) (9.08) (0.56) (1.55) (1.57)	
From 2 kV to 50 kV Voltage Discount, Facilities Related Demand - \$/kW From 2 kV to 50 kV From 51 kV to 250 kV Voltage Discount, Time-Related Demand - \$/kW From 51 kV to 250 kV From 51 kV to 250 kV Voltage Discount, Time-Related Demand - \$/kW From 51 kV to 250 kV From 51 kV to 250 kV From 51 kV to 250 kV Voltage Discount, Time-Related Demand - \$/kW From 51 kV to 250 kV From 51 kV to 250 kV From 51 kV to 250 kV Voltage Discount, Time-Related Demand - \$/kW From 51 kV to 250 kV From 51 kV to 250 kV From 51 kV to 250 kV Voltage Discount, Time-Related Demand - \$/kW From 51 kV to 250 kV From 51 kV to 250 kV Voltage Discount, Time-Related Demand - \$/kW From 51 kV to 250 kV From 51 kV to 250 kV From 51 kV to 250 kV Voltage Discount, Time-Related Demand - \$/kW From 51 kV to 250 kV From 51 kV to 250 kV From 51 kV to 250 kV Voltage Discount, Time-Related Demand - \$/kW From 51 kV to 550 kV	0.25498 0.06556 0.12373 0.06124 123.25 11.15 19.86 (0.14) (4.28) (9.08) (0.56) (1.55) (1.57)	
TOU-EV-4 Energy Charge - \$/kWh Summer Season On-Peak Off-Peak Off-Peak O.01613 0.04875 0.06488 0.01309 0.05247 Winter Season On-Peak Off-Peak 0.01613 0.04875 0.06488 0.01309 0.05247 Winter Season On-Peak O.01613 0.04842 0.06455 0.01309 0.04815 Customer Charge - \$/meter/month 94.65 0.00 94.65 123.25 Facilities Related Demand Charge - \$/kW 9.54 0.00 95.4 11.15 Time Related Demand Charge - \$/kW 0.00 18.62 18.62 0.00 19.86 Voltage Discount, Facilities Related Demand - \$/kW From 2 kV to 50 kV 0.19 0.00 0.19 0.00 0.19 0.00 0.19 0.00 0.00	0.25498 0.06556 0.12373 0.06124 123.25 11.15 19.86 (0.14) (4.28) (9.08) () (0.56) (1.55) (1.57)	
TOU-EV-4 Energy Charge - \$/kWh Summer Season On-Peak Off-Peak Off-Peak O.01613 0.04875 0.06488 0.01309 0.05247 Winter Season On-Peak Off-Peak 0.01613 0.04875 0.06488 0.01309 0.05247 Winter Season On-Peak Off-Peak 0.01613 0.04842 0.06455 0.01309 0.11064 0.01613 0.04842 0.06455 0.01309 0.04815 Customer Charge - \$/meter/month 94.65 0.00 94.65 123.25 Facilities Related Demand Charge - \$/kW 9.54 0.00 95.4 11.15 Time Related Demand Charge - \$/kW From 2 kV to 50 kV From 51 kV to 219 kV 220 kV and above Voltage Discount, Time-Related Demand - \$/kW From 2 kV to 50 kV 0.00 0.00 0.040 0.040 0.040 0.040 0.056 0.000 0.056 0.000 0.058 0.000 0.058 0.000 0.058 0.000 0.0000 0.0000 0.00000 0.00000 0.00000 0.00000 0.00000 0.00000 0.000000	0.25498 0.06556 0.12373 0.06124 123.25 11.15 19.86 (0.14) (4.28) (9.08) () (0.56) (1.55) (1.57)	
TOU-EV-4 Energy Charge - \$/kWh Summer Season On-Peak Off-Peak Off-Peak O.01613 0.04875 0.06488 0.01309 0.05247 Winter Season On-Peak Off-Peak 0.01613 0.04875 0.06488 0.01309 0.05247 Winter Season On-Peak O.01613 0.04842 0.06455 0.01309 0.04815 Customer Charge - \$/meter/month 94.65 0.00 94.65 123.25 Facilities Related Demand Charge - \$/kW 9.54 0.00 95.4 11.15 Time Related Demand Charge - \$/kW 0.00 18.62 18.62 0.00 19.86 Voltage Discount, Facilities Related Demand - \$/kW From 2 kV to 50 kV 0.019 0.00 0.019 0.00 0.019 0.00 0.019 0.00 0.00	0.25498 0.06556 0.12373 0.06124 123.25 11.15 19.86 (0.14) (4.28) (9.08) (0.56) (1.55) (1.57) (0.00140) (0.00311) (0.00315)	
Form 2 kV to 50 kV From 5 kV to 50 kV From 5 kV to 50 kV From 5 kV to 50 kV From 5 kV to 50 kV From 5 kV to 50 kV From 5 kV to 50 kV From 5 kV to 50 kV From 5 kV to 50 kV From 5 kV to 50 kV From 5 kV to 50 kV From 5 kV to 50 kV Voltage Discount, Time-Related Demand - \$/kW From 5 kV to 50 kV From 5 kV to 50 kV Voltage Discount, Energy - \$/kWh From 5 kV to 50 kV Voltage Discount, Energy - \$/kWh From 5 kV to 50 kV Voltage Discount, Energy - \$/kWh Energy - \$/kWh Prom 5 kV to 50 kV Prom 5 kV to 50 kV Voltage Discount, Energy - \$/kWh Prom 5 kV to 50 kV Voltage Discount, Facilities Related Demand - \$/kW From 5 kV to 50 kV Voltage Discount, Time-Related Demand - \$/kW From 5 kV to 50 kV Voltage Discount, Time-Related Demand - \$/kW From 5 kV to 50 kV Voltage Discount, Time-Related Demand - \$/kW From 5 kV to 50 kV Voltage Discount, Time-Related Demand - \$/kW Prom 5 kV to 50 kV Voltage Discount, Time-Related Demand - \$/kW Prom 5 kV to 50 kV Voltage Discount, Time-Related Demand - \$/kW Prom 5 kV to 50 kV Voltage Discount, Time-Related Demand - \$/kW Voltage Discount, Time-Related Demand - \$/kW Voltage Discount, Time-Related Demand - \$/kW Voltage Discount, Time-Related Demand - \$/kW Voltage Discount, Time-Related Demand - \$/kW Voltage Discount, Time-Related Demand - \$/kW Voltage Discount, Time-Related Demand - \$/kW Voltage Discount, Energy - \$/kWh Prom 5 kV to 50 kV Voltage Discount, Energy - \$/kWh Prom 5 kV to 50 kV Voltage Discount, Energy - \$/kWh Prom 5 kV to 50 kV Voltage Discount, Energy - \$/kWh Voltage Discount, Energy - \$/kWh Voltage Discount, Energy - \$/kWh Voltage Discount, Energy - \$/kWh Voltage Discount, Energy - \$/kWh Voltage Discount, Energy - \$/kWh Voltage Discount, Energy - \$/kWh Voltage Discount, Energy - \$/kWh Voltage Discount, Energy - \$/kWh Voltage Discount, Energy - \$/kWh Voltage Discount, Energy - \$/kWh Voltage Discount, Energy - \$/kWh Voltage Discount, Energy - \$/kWh Voltage Discount, Energy - \$/kWh Voltage Discount, Energy - \$/kWh Voltage Discount, Energy - \$/kWh Voltage Discount, Energy - \$/kWh Voltage	0.25498 0.06556 0.12373 0.06124 123.25 11.15 19.86 (0.14) (4.28) (9.08) () (0.56) (1.55)) (1.57)) (0.00311)) (0.00315)	

		Rates Eff	fective Decen	nber 2008	Proposed Rate	es Effective O	ctober 1, 2009	
Note: Resi	dential rates based on seven cent Tier 3 - Tier 5							
differential	and baseline allocations set at 55% of average							
	usage by CEC climate zone, assuming modification of rovided in Paragraph 4.b.iii and 4.b.v. CIA adjustment							Total Rate
	emented effective with rate changes made in 2010 for	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Change
TOU-GS-1								<u> </u>
	Energy Charge - \$/kWh Summer Season							
	On-Peak	0.05429	0.14968	0.20397	0.04757	0.31485	0.36242	77.68%
	Mid-peak Off-Peak	0.05429 0.05429	0.11926 0.07938	0.17355 0.13367	0.04757 0.04757	0.13377 0.05487	0.18134 0.10244	4.49% -23.36%
	Winter Season	0.03429	0.07936	0.13307	0.04757	0.00467	0.10244	-23.30%
	Mid-peak	0.05429	0.12232	0.17661	0.04757	0.07734	0.12491	-29.27%
	Off-Peak	0.05429	0.08352	0.13781	0.04757	0.05190	0.09947	-27.82%
	Customer Charge - \$/day	0.565	0.000	0.565	0.674	0.000	0.674	19.29%
	Three-Phase Service - \$/day	0.138	0.000	0.138	0.030	0.000	0.030	-78.26%
	Tillee-Filase Selvice - gruay	0.130	0.000	0.130	0.030	0.000	0.030	-70.20%
	Voltage Discount, Energy - \$/kWh	(0.00000)	(0.00007)	(0.00050)	(0.000.47)	(0.00047)	(0.00004)	4.500/
	From 2 kV to 50 kV From 51 kV to 219 kV	(0.00026) (0.00856)	(0.00227) (0.00494)	(0.00253) (0.01350)	(0.00047) (0.01474)	(0.00217) (0.00484)	(0.00264) (0.01958)	-4.50% -45.04%
	220 kV and above	(0.00000)	(0.00101)	(0.01000)	(0.01492)	(0.00490)	(0.01982)	10.0170
	California Alternate Rates for	400.00		400.00	400.00		100.00	0.0001
	Energy Discount - %	100.00		100.00	100.00		100.00	0.00%
TOU-GS-3	(Option A)							
	Energy Charge - \$/kWh Summer Season							
	Summer Season On-Peak	0.01525	0.29651	0.31176	0.01244	0.24154	0.25398	-18.53%
	Mid-peak	0.01525	0.12675	0.14200	0.01244	0.11376	0.12620	-11.13%
	Off-Peak Winter Season	0.01525	0.05341	0.06866	0.01244	0.06118	0.07362	7.22%
	Mid-peak	0.01525	0.08943	0.10468	0.01244	0.06521	0.07765	-25.82%
	Off-Peak	0.01525	0.05626	0.07151	0.01244	0.05090	0.06334	-11.42%
	Customer Charge - \$/month	367.02	0.00	367.02	434.25	0.00	434.25	18.32%
	Facilities Related	007.02	0.00	007.02	101.20	0.00	101.20	10.0270
	Demand Charge - \$/kW	9.86	0.00	9.86	12.16	0.00	12.16	23.33%
TOU-GS-3	(Option B)							
	Energy Charge - \$/kWh							
	Summer Season On-Peak	0.01525	0.10180	0.11705	0.01244	0.11486	0.12730	8.76%
	Mid-peak	0.01525	0.08084	0.09609	0.01244	0.08431	0.09675	0.69%
	Off-Peak	0.01525	0.05341	0.06866	0.01244	0.06118	0.07362	7.22%
	Winter Season Mid-peak	0.01525	0.08295	0.09820	0.01244	0.06521	0.07765	-20.93%
	Off-Peak	0.01525	0.05626	0.03020	0.01244	0.05090	0.06334	-11.42%
		007.00		007.00	404.05		404.05	40.000/
	Customer Charge - \$/month Facilities Related	367.02	0.00	367.02	434.25	0.00	434.25	18.32%
	Demand Charge - \$/kW	9.86	0.00	9.86	12.16	0.00	12.16	23.33%
	Time Related Demand Charge - \$/kW Summer Season							
	On-Peak	0.00	16.36	16.36	0.00	15.09	15.09	-7.76%
	Mid-Peak	0.00	5.61	5.61	0.00	3.58	3.58	-36.19%
	Winter Season							
	Mid-Peak	0.00	0.00					
	Off-Peak	0.00	0.00					
	Voltage Discount, Time-Related Demand - \$/kW							
	From 2 kV to 50 kV	0.00	(0.39)	(0.39)	0.00	(0.23)	(0.23)	41.03%
	From 51 kV to 219 kV	0.00	(1.04)	(1.04)	0.00	(0.64)	(0.64)	38.46%
	220 kV and above				0.00	(0.65)	(0.65)	
TOU-GS-3	(Both Options)							
	Voltage Discount, Facilities Related Demand - \$/kW From 2 kV to 50 kV	(0.19)	0.00	(0.19)	(0.18)	0.00	(0.18)	5.26%
	From 51 kV to 219 kV	(6.25)	0.00	(6.25)	(5.66)	0.00	(5.66)	9.44%
	220 kV and above	. 7		. ,	(9.86)	0.00	(9.86)	
	Voltage Discount, Energy - \$/kWh From 2 kV to 50 kV	0.00000	(0.00199)	(0.00199)	0.00000	(0.00138)	(0.00138)	30.65%
	From 51 kV to 219 kV	0.00000	(0.00133)	(0.00433)	0.00000	(0.00307)	(0.00307)	29.10%
	220 kV and above				0.00000	(0.00311)	(0.00311)	
	Power Factor Adjustment - \$/kVA Greater than 50 kV	0.20	0.00	0.20	0.32	0.00	0.32	60.00%
	50 kV or less	0.18	0.00	0.18	0.32	0.00	0.27	50.00%
	CARE Energy Discount %	100.00		100.00	400.00		100.00	0.000/
	CARE Energy Discount - %	100.00		100.00	100.00		100.00	0.00%

	Rates Ef	fective Decer	nber 2008		Proposed Rate	es Effective C	october 1, 2009	
Note: Residential rates based on seven cent Tier 3 - Tier 5								
differential and baseline allocations set at 55% of average								
aggregate usage by CEC climate zone, assuming modification of								
AB1X as provided in Paragraph 4.b.iii and 4.b.v. CIA adjustment	l					_		Total Rate
to be implemented effective with rate changes made in 2010 for	Delivery	Generation	Total Rate]	Delivery	Generation	Total Rate	Change
TOU-GS-3-CPP								
Critical Peak Pricing								
Time-of-Use Pricing Option Energy Charge - \$/kWh								
Summer Season								
On-Peak	0.01525	0.09857	0.11382		0.01244	0.11486	0.12730	11.84%
Mid-peak	0.01525	0.07820	0.09345		0.01244	0.08431	0.09675	3.53%
Off-Peak	0.01525	0.05341	0.06866		0.01244	0.06118	0.07362	7.22%
Winter Season								
Mid-peak	0.01525	0.08025	0.09550		0.01244	0.06521	0.07765	-18.69%
Off-Peak	0.01525	0.05626	0.07151		0.01244	0.05090	0.06334	-11.42%
OII-1 Calk	0.01020	0.00020	0.07 101		0.01244	0.00000	0.00004	-11.72/0
Customer Charge - \$/month	367.02	0.00	367.02		434.25	0.00	434.25	18.32%
Customer Charge - \$/month	307.02	0.00	307.02		434.23	0.00	434.23	10.32%
5 '''' B. I. I. B. I. I. B. I. I. B. I. I. B. I. I. B. I. I. B. I. I. B. I. I. B. I. I. B. I. I. B. I. I. B. I. I. B. I. I. B.	0.00				40.40		40.40	00.000/
Facilities Related Demand Charge - \$/kW	9.86	0.00	9.86		12.16	0.00	12.16	23.33%
Time Related Demand Charge - \$/kW								
Summer Season On-Peak		15.79	15.79		0.00	15.09	15.09	-4.43%
Mid-Peak		0.00	0.00		0.00	3.58	3.58	
Winter Season Mid-Peak	0.00	0.00	0.00		0.00	0.00	0.00	
Voltage Discount, Facilities Related Demand - \$/kW								
From 2 kV to 50 kV	(0.19)	0.00	(0.19)		(0.18)	0.00	(0.18)	5.26%
From 51 kV to 219 kV	(6.25)	0.00	(6.25)		(5.66)	0.00	(5.66)	9.44%
220 kV and above	,				(9.86)	0.00	(9.86)	
Voltage Discount, Time-Related Demand - \$/kW					()		()	
From 2 kV to 50 kV	0.00	(0.40)	(0.40)		0.00	(0.23)	(0.23)	42.50%
From 51 kV to 219 kV	0.00	(1.04)	(1.04)		0.00	(0.64)	(0.64)	38.46%
220 kV and above	0.00	(1.04)	(1.04)		0.00	(0.65)	(0.65)	30.4070
Voltage Discount, Energy - \$/kWh					0.00	(0.03)	(0.03)	
From 2 kV to 50 kV	0.00000	(0.00199)	(0.00199)		0.00000	(0.00138)	(0.00138)	30.65%
From 51 kV to 219 kV	0.00000	(0.00433)	(0.00433)		0.00000	(0.00307)		29.10%
220 kV and above					0.00000	(0.00311)	(0.00311)	
Power Factor Adjustment - \$/kVA								
Greater than 50 kV	0.20	0.00	0.20		0.32	0.00	0.32	60.00%
50 kV or less	0.18	0.00	0.18		0.27	0.00	0.27	50.00%
CARE Energy Discount - %	100.00%		100.00%		100.00%		100.00%	
CPP Event Energy Charge - \$kWh					0.00000	1.36229	1.36229	
Summer CPP Non-Event Credit								
On-Peak Demand Credit - \$kWh					0.00	(11.62)	(11.62)	
TOU-GS-3 (Option R)								
Energy Charge - \$/kWh								
Summer Season								
On-Peak					0.02948	0.24154	0.27102	
Mid-peak					0.02948	0.11376	0.14324	
Off-Peak					0.02948	0.06118	0.09066	
Winter Season					5.02540	0.00110	5.05000	
Mid-peak					0.02948	0.06521	0.09469	
Off-Peak					0.02948	0.05090	0.09469	
OII-Peak					0.02948	0.00090	0.00038	
Customer Charge Chargeth					404.05	0.00	404.05	
Customer Charge - \$/month					434.25	0.00	434.25	
Facilities Related								
Demand Charge - \$/kW					6.08	0.00	6.08	
Voltage Discount, Facilities Related Demand - \$/kW								
From 2 kV to 50 kV					-0.09	0.00	-0.09	
From 51 kV to 219 kV					-2.83	0.00	-2.83	
220 kV and above					-3.78	0.00	-3.78	
Voltage Discount, Energy - \$/kWh								
From 2 kV to 50 kV					0.00000	(0.00138)	(0.00138)	
From 51 kV to 219 kV					0.00000	(0.00307)		
220 kV and above					0.00000			
Voltage Discount, Time-Related Demand - \$/kW						,	(==== 1)	
From 2 kV to 50 kV								
above 50 kV								
220 kV and above								
Power Factor Adjustment - \$/kVA								
					0.00	0.00	0.00	
Greater than 50 kV					0.32	0.00	0.32	
50 kV or less					0.27	0.00	0.27	
0405.5								
CARE Energy Discount - %					100.00	0.00	100.00	

	Rates Eff	ective Decer	nber 2008	Proposed Rate	es Effective O	ctober 1, 2009	
Note: Residential rates based on seven cent Tier 3 - Tier 5 differential and baseline allocations set at 55% of average							
aggregate usage by CEC climate zone, assuming modification of AB1X as provided in Paragraph 4.b.iii and 4.b.v. CIA adjustment							Total Rate
to be implemented effective with rate changes made in 2010 for TOU-GS-3-SOP	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Change
Energy Charge - \$/kWh Summer Season							
On-Peak	0.01525	0.10538	0.12063	0.01244	0.12481	0.13725	13.78%
Mid-peak Super Off-Peak	0.01525 0.01525	0.07372 0.04469	0.08897 0.05994	0.01244 0.01244	0.06671 0.04058	0.07915 0.05302	-11.04% -11.54%
Winter Season Mid-peak	0.01525	0.07393	0.08918	0.01244	0.06364	0.07608	-14.69%
Super Off-Peak	0.01525	0.04421	0.05946	0.01244	0.04060	0.05304	-10.80%
Customer Charge - \$/month	367.02	0.00	367.02	434.25	0.00	434.25	18.32%
Facilities Related Demand Charge - \$/kW	9.86	0.00	9.86	12.16	0.00	12.16	23.33%
Time Related Demand Charge - \$/kW Summer Season							
On-Peak Mid-peak	0.00 0.00	22.92 0.44	22.92 0.44	0.00 0.00	23.18 0.49	23.18 0.49	1.13% 11.36%
Winter Season							
Mid-peak	0.00	0.08	0.08	0.00	0.09	0.09	12.50%
Voltage Discount, Facilities Related Demand - \$/kW							
From 2 kV to 50 kV From 51 kV to 219 kV	(0.19) (6.25)	0.00	(0.19) (6.25)	(0.18) (5.66)	0.00	(0.18) (5.66)	5.26% 9.44%
220 kV and above Voltage Discount, Time-Related Demand - \$/kW				(9.86)	0.00	(9.86)	
From 2 kV to 50 kV	0.00	(0.39)	(0.39)	0.00	(0.23)	(0.23)	41.03%
From 51 kV to 219 kV 220 kV and above	0.00	(1.04)	(1.04)	0.00 0.00	(0.64) (0.65)	(0.64) (0.65)	38.46%
Voltage Discount, Energy - \$/kWh From 2 kV to 50 kV	0.00000	(0.00199)	(0.00199)	0.00000	(0.00138)	(0.00138)	30.65%
From 51 kV to 219 kV 220 kV and above	0.00000	(0.00433)	(0.00433)	0.00000 0.00000	(0.00307) (0.00311)	(0.00307) (0.00311)	29.10%
Power Factor Adjustment - \$/kVA Greater than 50 kV	0.20	0.00	0.20	0.32	0.00	0.32	60.00%
50 kV or less	0.18	0.00	0.18	0.32	0.00	0.27	50.00%
TOU-8 (Below 2kV) - Option A							
Energy Charge - \$/kWh Summer Season							
On-Peak Mid-peak				0.01225 0.01225	0.30216 0.12025	0.31441 0.1325	
Off-Peak Winter Season				0.01225	0.05451	0.06676	
Mid-peak				0.01225	0.07244	0.08469	
Off-Peak				0.01225	0.05159	0.06384	
Customer Charge - \$/month Facilities Related				530.50	0.00	530.5	
Demand Charge - \$/kW				11.60	0.00	11.6	
Power Factor Adjustment - \$/kVA				0.27	0.00	0.27	
TOU-8 (From 2 kV to 50 kV) - Option A							
Energy Charge - \$/kWh Summer Season							
On-Peak Mid-peak				0.01201 0.01201	0.30545 0.11968	0.31746 0.13169	
Off-Peak Winter Season				0.01201	0.05332	0.06533	
Mid-peak				0.01201	0.07080		
Off-Peak				0.01201	0.04976	0.06177	
Customer Charge - \$/month Facilities Related				284.75	0.00	284.75	
Demand Charge - \$/kW				10.98	0.00	10.98	
Power Factor Adjustment - \$/kVA				0.27	0.00	0.27	
TOU-8 (Above 50 kV) - Option A Energy Charge - \$/kWh							
Summer Season							
On-Peak Mid-peak				0.01116 0.01116	0.26116 0.10047	0.27232 0.11163	
Off-Peak Winter Season				0.01116	0.04571	0.05687	
Mid-peak Off-Peak				0.01116 0.01116	0.06391 0.04539	0.07507 0.05655	
Customer Charge - \$/month Facilities Related				2183.50	0.00	2183.50	
Demand Charge - \$/kW				4.05	0.00	4.05	
Power Factor Adjustment - \$/kVA				0.32	0.00	0.32	
Voltage Discount, 220 kV and above Facilities Related Dema	and - \$/k\\/			1.00	0.00	1 00	
Time-Related Demand				-1.99	0.00	-1.99	
Summer Energy - \$/kWh				0.00 0.00000	0.00 -0.00064	0.00 -0.00064	

		Rates Eff	ective Decen	nber 2008	Proposed R	ates Effective C	October 1, 2009	
							,,	
Note: Residential rates based on seven cent T differential and baseline allocations set at 55%								
aggregate usage by CEC climate zone, assur	ning modification of							
AB1X as provided in Paragraph 4.b.iii and 4.b to be implemented effective with rate changes		Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Total Rate Change
TOU-8-B (Below 2kV)	made in 2010 for		Contraction	Total Hato		Contraction	Total rate	
Energy Charge - \$/kWh								
Sur	nmer Season On-Peak	0.01481	0.09517	0.10998	0.0122	25 0.12318	0.13543	23.14%
	Mid-peak	0.01481	0.07552	0.09033	0.0122		0.09335	3.34%
NAC-	Off-Peak	0.01481	0.04978	0.06459	0.0122	25 0.05451	0.06676	3.36%
WIF	nter Season Mid-peak	0.01481	0.07750	0.09231	0.0122	25 0.07244	0.08469	-8.25%
	Off-Peak	0.01481	0.05247	0.06728	0.0122		0.06384	-5.11%
Customer Channel Channel		450.04	0.00	450.04	F20 F	0.00	520.50	45.000/
Customer Charge - \$/month Facilities Related		458.04	0.00	458.04	530.5	0.00	530.50	15.82%
Demand Charge - \$/k		10.77	0.00	10.77	11.6	0.00	11.60	7.71%
Time Related Demand Charge - \$								
Sui	nmer Season On-Peak	0.00	15.23	15.23	0.0	0 18.74	18.74	23.05%
	Mid-Peak	0.00	5.14	5.14	0.0	5.28	5.28	2.72%
Win	nter Season							
VVII	Mid-Peak	0.00			0.0	0.00	0.00	
	Off-Peak	0.00			0.0		0.00	
Power Factor Adjustment - \$/kVA		0.18	0.00	0.18	0.2	7 0.00	0.27	50.00%
rower actor Aujustment - \$/KVA		0.18	0.00	0.10	0.2	, 0.00	0.27	50.00%
TOU-8-B (From 2 kV to 50 kV)								
Energy Charge - \$/kWh	nmer Season							
Sui	On-Peak	0.01434	0.09652	0.11086	0.0120	0.08907	0.10108	-8.82%
	Mid-peak	0.01434	0.07662	0.09096	0.0120		0.08627	-5.16%
Win	Off-Peak nter Season	0.01434	0.05049	0.06483	0.0120	0.05332	0.06533	0.77%
****	Mid-peak	0.01434	0.07864	0.09298	0.0120	0.07080	0.08281	-10.94%
	Off-Peak	0.01434	0.05324	0.06758	0.0120	0.04976	0.06177	-8.60%
Customer Charge - \$/month		275.69	0.00	275.69	284.7	5 0.00	284.75	3.29%
Facilities Related		210.00	0.00	270.00	204.7	0.00	204.70	0.2370
Demand Charge - \$/		10.21	0.00	10.21	10.9	B 0.00	10.98	7.54%
Time Related Demand Charge - \$	5/kW nmer Season							
Sui	On-Peak	0.00	15.48	15.48	0.0	0 22.70	22.70	46.64%
	Mid-Peak	0.00	5.24	5.24	0.0	0 6.36	6.36	21.37%
Win	nter Season							
	Mid-Peak	0.00			0.0	0.00	0.00	
	Off-Peak	0.00			0.0	0.00	0.00	
Power Factor Adjustment - \$/kVA		0.18	0.00	0.18	0.2	7 0.00	0.27	50.00%
* *								
TOU-8-B (Above 50 kV)								
Energy Charge - \$/kWh	nmer Season							
ou.	On-Peak	0.01289	0.07500	0.08789	0.011	0.08232	0.09348	6.36%
	Mid-peak	0.01289	0.05952	0.07241	0.011		0.07691	6.21%
Win	Off-Peak nter Season	0.01289	0.03911	0.05200	0.011	16 0.04571	0.05687	9.37%
****	Mid-peak	0.01289	0.06123	0.07412	0.011		0.07508	1.30%
	Off-Peak	0.01289	0.04137	0.05426	0.011	0.04540	0.05656	4.24%
Customer Charge - \$/month		2,427.22	0.00	2,427.22	2,183.5	0.00	2,183.50	-10.04%
Facilities Related		,		,	_,0.0		,	
Demand Charge - \$/k		2.80	0.00	2.80	4.0	5 0.00	4.05	44.64%
Time Related Demand Charge - \$ Sur	nmer Season							
ou	On-Peak	0.00	12.22	12.22	0.0		19.73	61.46%
	Mid-Peak	0.00	4.21	4.21	0.0	0 5.21	5.21	23.75%
Win	nter Season							
	Mid-Peak	0.00			0.0		0.00	
	Off-Peak	0.00			0.0	0.00	0.00	
Power Factor Adjustment - \$/kVA		0.20	0.00	0.20	0.3	2 0.00	0.32	60.00%
Voltage Discount, 220 kV and a		(0.05)	0.00	(0.05)	/4.0	9) 0.00	(4.00)	100 470/
	ed Demand - \$/kW ed Demand - \$/kW	(0.95)	0.00	(0.95)	(1.9	0.00	(1.99)	-109.47%
	Summer	0.00	(0.09)	(0.09)	0.0			-66.67%
	Energy - \$/kWh	0.00000	(0.00087)	(0.00087)		0 (0.00064)	(0.00064)	26.44%

	Rates Ef	fective Decer	mber 2008	Proposed Ra	ites Effective C	October 1, 2009	
						, ,	
Note: Residential rates based on seven cent Tier 3 - Tier 5 differential and baseline allocations set at 55% of average							
aggregate usage by CEC climate zone, assuming modification							Total Rate
AB1X as provided in Paragraph 4.b.iii and 4.b.v. CIA adjustme to be implemented effective with rate changes made in 2010 for	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Change
TOUR Beatwar B (Balance State							
TOU-8-Backup-B (Below 2kV) Energy Charge - \$/kWh							
Summer Season							
On-Pei Mid-pei		0.09517 0.07552	0.10998 0.09033	0.0122 0.0122		0.13543 0.09335	23.14% 3.34%
Off-Pea		0.04978	0.06459	0.0122		0.06676	3.36%
Winter Season							
Mid-pe Off-Pea		0.07750 0.05247	0.09231 0.06728	0.0122 0.0122		0.08469 0.06384	-8.25% -5.11%
Customer Charge - \$/month	444.51	0.00	444.51	437.69	0.00	437.69	-1.53%
Time Related Demand Charge - \$/kW							
Summer Season On-Pe	ak 0.00	15.23	15.23	0.00	18.74	18.74	23.05%
Mid-Pei		5.14	5.14	0.00		5.28	2.72%
ME-to- O.							
Winter Season Mid-Pe	ak 0.00			0.00	0.00	0.00	
Off-Pea				0.00		0.00	
Power Factor Adjustment - \$/kVA	0.18	0.00	0.18	0.27	0.00	0.27	50.00%
•	5.10	3.50	00	5.27	3.30	U.E.	55.5570
TOU-8-Backup-B (From 2 kV to 50 kV) Energy Charge - \$/kWh							
Summer Season							
On-Per		0.09652	0.11086	0.0120		0.10108	-8.82%
Mid-per Off-Per		0.07662 0.05049	0.09096 0.06483	0.0120 0.0120		0.08627 0.06533	-5.16% 0.77%
Winter Season	an 0.01101	0.00010	0.00100	0.0120	. 0.00002	0.00000	0.1170
Mid-pe: Off-Pe:		0.07864 0.05324	0.09298 0.06758	0.0120 0.0120		0.08281 0.06177	-10.94% -8.60%
Customer Charge - \$/month	267.71	0.00	267.71	234.96	0.00	234.96	-12.23%
Time Related Demand Charge - \$/kW							
Summer Season On-Pe	ak 0.00	15.48	15.48	0.00	22.70	22.70	46.64%
Mid-Per		5.24	5.24	0.00		6.36	21.37%
Winter Season							
Mid-Pe				0.00	0.00	0.00	
Off-Pea	ak 0.00			0.00	0.00	0.00	
Power Factor Adjustment - \$/kVA	0.18	0.00	0.18	0.27	0.00	0.27	50.00%
TOU-8-Backup-B (Above 50 kV)							
Energy Charge - \$/kWh							
Summer Season							
On-Pei Mid-pei		0.07500 0.05952	0.08789 0.07241	0.0111 0.0111		0.09348 0.07691	6.36% 6.21%
Off-Pea		0.03911	0.05200	0.0111		0.05687	9.37%
Winter Season Mid-pe	ak 0.01289	0.06123	0.07412	0.0111	6 0.06392	0.07508	1.30%
Off-Pea		0.00123	0.05426	0.0111		0.05656	4.24%
Contains Channel Channel	0.055.00	0.00	0.055.00	4 004 00	0.00	4 004 00	00.50%
Customer Charge - \$/month	2,355.83	0.00	2,355.83	1,801.69	0.00	1,801.69	-23.52%
Time Related Demand Charge - \$/kW							
Summer Season On-Pe	ak 0.00	12.22	12.22	0.00	19.73	19.73	61.46%
Mid-Pe		4.21	4.21	0.00		5.21	23.75%
Winter Season							
Mid-Pe:				0.00		0.00	
Off-Pea	ak 0.00			0.00	0.00	0.00	
Power Factor Adjustment - \$/kVA	0.20	0.00	0.20	0.32	0.00	0.32	60.00%
Voltage Discount, 220 kV and above							
Facilities Related Demand - \$/k		0.00	(0.95)	(1.99	0.00	(1.99)	-109.47%
Time-Related Demand - \$/k		(0.00)	(0.00)	0.00	(0.45)	(0.45)	66 670/
Summ Energy - \$/kV		(0.09) (0.00087)		0.00			-66.67% 26.44%
37							

	Rates Ef	fective Decen	nber 2008	Propose	ed Rat	es Effective O	ctober 1, 2009	
Note: Residential rates based on seven cent Tier 3 - Tier 5								
differential and baseline allocations set at 55% of average aggregate usage by CEC climate zone, assuming modification of								
AB1X as provided in Paragraph 4.b.iii and 4.b.v. CIA adjustment								Total Rate
to be implemented effective with rate changes made in 2010 for	Delivery	Generation	Total Rate	Deliv	ery	Generation	Total Rate	Change
TOU-8-CPP (Below 2kV)								
Critical Peak Pricing Energy Charge - \$/kWh								
Summer Season On-Peak	0.01481	0.08698	0.10179	0	01225	0.12318	0.13543	33.05%
Mid-peak	0.01481	0.06875	0.08356	0.	01225	0.08110	0.09335	11.72%
Off-Peak Winter Season	0.01481	0.04978	0.06459	0.	01225	0.05451	0.06676	3.36%
Mid-peak Off-Peak	0.01481 0.01481	0.07058 0.05247	0.08539 0.06728		01225 01225		0.08469 0.06384	-0.82% -5.11%
Оп-Реак	0.01481	0.05247	0.06728	U.	01225	0.05159	0.06384	-5.11%
Customer Charge - \$/month Facilities Related	458.04	0.00	458.04	5	30.50	0.00	530.50	15.82%
Demand Charge - \$/kW	10.77	0.00	10.77		11.60	0.00	11.60	7.71%
Time Related Demand Charge - \$/kW Summer Season								
On-Peak Mid-Peak	0.00	15.23 5.14	15.23 5.14		0.00	18.74 5.28	18.74 5.28	23.05% 2.72%
Off-Peak	0.00	5.14	5.14		0.00	3.20	3.20	2.12/0
Winter Season Mid-Peak	0.00				0.00	0.00	0.00	
Off-Peak	0.00				0.00	0.00	0.00	
Power Factor Adjustment - \$/kVA	0.18	0.00	0.18		0.27	0.00	0.27	50.00%
CPP Event Energy Charge - \$kWh Summer CPP Non-Event Credit				0.0	0000	1.36229	1.36229	
On-Peak Demand Credit - \$kWh					0.00	(12.47)	(12.47)	
TOU-8-CPP (From 2 kV to 50 kV) Critical Peak Pricing Energy Charge - \$\(\)kWh								
Summer Season On-Peak	0.01424	0.08847	0.10391	0	01201	0.08907	0.10109	1 699/
Mid-peak	0.01434 0.01434	0.06999	0.10281 0.08433	0.	01201 01201	0.07426	0.10108 0.08627	-1.68% 2.30%
Off-Peak Winter Season	0.01434	0.05049	0.06483	0.	01201	0.05332	0.06533	0.77%
Mid-peak	0.01434	0.07185	0.08619		01201		0.08281	-3.92%
Off-Peak	0.01434	0.05324	0.06758	0.	01201	0.04976	0.06177	-8.60%
Customer Charge - \$/month Facilities Related	275.69	0.00	275.69	2	84.75	0.00	284.75	3.29%
Demand Charge - \$/kW Time Related Demand Charge - \$/kW	10.21	0.00	10.21		10.98	0.00	10.98	7.54%
Summer Season On-Peak	0.00	15.48	15.48		0.00	22.70	22.70	46.64%
Mid-Peak Off-Peak	0.00	5.24	5.24		0.00	6.36	6.36	21.37%
Winter Season								
Mid-Peak Off-Peak	0.00				0.00	0.00	0.00	
Power Factor Adjustment - \$/kVA	0.18	0.00	0.18		0.27	0.00	0.27	50.00%
CPP Event Energy Charge - \$kWh	0.10	0.00	0.10	0.0	0000	1.33322	1.33322	30.0070
Summer CPP Non-Event Credit On-Peak Demand Credit - \$kWh					0.00	(12.20)	(12.20)	
TOU-8-CPP (Above 50 kV)								
Critical Peak Pricing								
Energy Charge - \$/kWh Summer Season								
On-Peak	0.01289 0.01289	0.06940 0.05484	0.08229 0.06773		01116 01116		0.09348 0.07691	13.60% 13.55%
Mid-peak Off-Peak	0.01289	0.05484	0.05200		01116 01116		0.07691	9.37%
Winter Season Mid-peak	0.01289	0.05646	0.06935	0.	01116	0.06392	0.07508	8.26%
Off-Peak	0.01289	0.04137	0.05426		01116		0.05656	4.24%
Customer Charge - \$/month	2,427.22	0.00	2,427.22	2,1	33.50	0.00	2,183.50	-10.04%
Facilities Related Demand Charge - \$/kW Time Related Demand Charge - \$/kW	2.80	0.00	2.80		4.05	0.00	4.05	44.64%
Summer Season On-Peak	0.00	12.22	12.22		0.00	19.73	19.73	61.46%
Mid-Peak Off-Peak	0.00	4.21	4.21		0.00	5.21	5.21	23.75%
Winter Season								
Mid-Peak Off-Peak	0.00				0.00	0.00	0.00	
Power Factor Adjustment - \$/kVA	0.20	0.00	0.20		0.32	0.00	0.32	60.00%
CPP Event Energy Charge - \$kWh	0.20	0.00	0.20	0.0	0.32	1.28157	1.28157	00.00/6
Summer CPP Non-Event Credit On-Peak Demand Credit - \$kWh					0.00	(13.02)	(13.02)	
Voltage Discount, 220 kV and above						, ,	,	
Facilities Related Demand - \$/kW	(0.95)	0.00	(0.95)		(1.99)	0.00	(1.99)	-109.47%
Time-Related Demand - \$/kW Summer	0.00	(0.09)	(0.09)		0.00	(0.15)	(0.15)	-66.67%
Energy - \$/kWh	0.00000	(0.00087)	(0.00087)		00000		(0.00064)	26.44%

Rates Effective December 2008 Principle Rules Rule			D	D	1 0000	1 5	10.	F# 11 0		
### Total Rate T			Rates E	ttective Dece	mber 2008	Propo	sed Rate	es Effective O	ctober 1, 2009	
Total Rate Delivery Generation Total Rate Delivery Generation Total Rate Delivery Generation Total Rate Delivery Generation Total Rate Total Rate Total Rate Total Rate Delivery Generation Total Rate Total Rate Total Rate Delivery Generation Total Rate Delivery Generation Total Rate Delivery Generation Total Rate Total Rate Total Rate Delivery Generation Total Rate Delivery Generation Total Rate Total Rate Total Rate Delivery Generation Total Rate Delivery Generation Total Rate Delivery Generation Total Rate Total Rate Total Rate Delivery Generation Total Rate Total Rate Total Rate Total Rate Delivery Generation Total Rate Total R	Note: Residential rates based on seven	cent Tier 3 - Tier 5								
Toular Paragraph 4 bit and 4 by CM adjustment to be implemented efficitive with rate defictive with rate deficitive with rate of the property of t										
Does implemented effective with rate changes made in 2010 for Delivery Generation Total Rate Chan Rate Ch										Total Rate
Energy Charge - \$IkWh			Delivery	Generation	Total Rate	De	livery	Generation	Total Rate	Change
Energy Charge - \$IkWh				•	•					
Summer Season On-Peak 0.02802 0.30216 0.32818 Mid-peak 0.02802 0.102502 0.14827 Off-Peak 0.02802 0.02502 0.14827 Off-Peak 0.02802 0.05451 0.08053 Off-Peak 0.02802 0.05451 0.08053 Off-Peak 0.02802 0.05159 0.07761 Off-Peak 0.02802 Off-Peak 0.02802 Off-Peak 0.02802 Off-Peak 0.02802 Off-Peak										
On-Peak 0,26602 0,30216 0,32818 Mid-peak 0,26602 0,10255 0,1	Energy Charge - \$/kvvn	Summer Season								
Off-Peak 0.02602 0.05451 0.08053 Mici-peak 0.02602 0.07244 0.08046 Off-Peak 0.02602 0.07144 0.08046 Off-Peak 0.02602 0.05159 0.07761 Off-Peak 0.02602 0.05159 0.07761 Off-Peak 0.02602 0.05159 0.07761 Off-Peak 0.02603 Off-Peak 0.02603 Off-Peak 0.027 Off-Peak 0.027 Off-Peak 0.027 Off-Peak 0.02406 Off-Peak Off-Peak 0.02406 Off-Peak O							0.02602	0.30216	0.32818	
Winter Season Mich-peak 0.02602 0.07244 0.09846 O.07612 O.07761 O.0776							0.02602	0.12025	0.14627	
Mid-peak Off-Peak							0.02602	0.05451	0.08053	
Off-Peak								0.07044	0.00040	
Customer Charge - \$/month 530.50 0.00 530.50 Power Factor Adjustment - \$/kVA 0.27 0.00 0.27 TOU-8 (From 2 kV to 50 kV) - Option R										
Facilities Related Demand Charge - \$ikW	OII-Feak				'	J.U20U2	0.05159	0.07761		
Demand Charge - \$\text{kVA}	Customer Charge - \$/mor	nth					530.50	0.00	530.50	
Power Factor Adjustment - \$/kVA		*****								
TOU-8 (From 2 kV to 50 kV) - Option R Energy Charge - \$/kWh Summer Season On-Peak Off-Peak O	Demand Char	ge - \$/kW					5.80	0.00	5.80	
TOU-8 (From 2 kV to 50 kV) - Option R Energy Charge - \$/kWh Summer Season On-Peak Off-Peak O	Power Factor Adjustment	- \$/kVA					0.27	0.00	0.27	
Energy Charge - \$/kWh Summer Season On-Peak Mid-peak Off-Peak Ou2406 O130545 O132951 Mid-peak O1406 O14076 O17968 Mid-peak O102406 O17978 Winter Season Mid-peak O02406 O17980 O07382 Customer Charge - \$/month Facilities Related Demand Charge - \$/kWA O127 TOU-8 (Above 50 kV) - Option R Energy Charge - \$/kWA O17982 Summer Season On-Peak O17982 O17982 TOU-8 (Above 50 kV) - Option R Energy Charge - \$/kWA O17982 Customer Charge - \$/kWA O17982 TOU-8 (Above 50 kV) - Option R Energy Charge - \$/kWA O17982 Customer Charge - \$/kWA O18980 Winter Season O18980 Winter Season Mid-peak O19990 O1	. over i deter rajustinent	Ψ					0.27	0.00	0.21	
Summer Season		on R								
On-Peak	Energy Charge - \$/kvvn	Summer Season								
Mid-peak 0,02406 0,1368 0,14374 0,02406 0,05332 0,07738							0.02406	0.30545	0.32951	
Winter Season Mid-peak 0.02406 0.07080 0.09486 Off-Peak 0.02406 0.04976 0.07382 Off-Peak 0.02406 0.04976 0.07382 Off-Peak 0.02406 0.04976 0.07382 Off-Peak 0.02406 0.04976 0.07382 Off-Peak 0.02406 0.04976 O.07382 Off-Peak 0.000 0.000 0.000 Off-Peak 0.000 0.000 Off-Peak Off-										
Mid-peak Off-Peak 0.02406 0.07080 0.09486 Off-Peak 0.02406 0.04976 0.07382 0.07382 0.07486 0.02406 0.04976 0.07382 0.07382 0.004976 0.07382 0.07382 0.004976 0.07382 0.07382 0.004976 0.07382 0.004976 0.07382 0.07382 0.004976 0.07382 0.004976 0.07382 0.004976 0.07382 0.004976 0.07382 0.004976 0.07482 0.		Off-Peak					0.02406	0.05332	0.07738	
Off-Peak 0.02406 0.04976 0.07382										
Customer Charge - \$/month										
Facilities Related Demand Charge - \$/kW		Оп-Реак					J.02406	0.04976	0.07382	
Demand Charge - \$/kW 5.49 0.00 5.49	Customer Charge - \$/mor	nth					284.75	0.00	284.75	
Power Factor Adjustment - \$/kVA 0.27 0.00 0.27 TOU-8 (Above 50 kV) - Option R Energy Charge - \$/kWh Summer Season On-Peak Mid-peak Off-Peak 0.01309 0.06116 0.27425 Mid-peak 0.01309 0.04571 0.05880 Winter Season Mid-peak 0.01309 0.04571 0.05880 Winter Season Mid-peak 0.01309 0.04571 0.05880 Off-Peak 0.01309 0.04571 0.05880 Winter Season Mid-peak 0.01309 0.04539 0.05848 Customer Charge - \$/month Facilities Related Demand Charge - \$/kW 3.06 0.00 3.06 Power Factor Adjustment - \$/kVA 3.06 0.00 3.06 Voltage Discount, 220 kV and above Facilities Related Demand - \$/kW Summer 0.00 0.00 0.00										
TOU-8 (Above 50 kV) - Option R Energy Charge - \$/kWh Summer Season On-Peak Mid-peak Off-Peak Winter Season Mid-peak Off-Peak Winter Season Mid-peak Off-Peak Off-Peak 0.01309 0.04571 0.05860 Winter Season Mid-peak Off-Peak 0.01309 0.04571 0.05860 Winter Season Mid-peak 0.01309 0.04539 0.05848 Customer Charge - \$/month Facilities Related Demand Charge - \$/kW 3.06 Power Factor Adjustment - \$/kVA 3.06 Voltage Discount, 220 kV and above Facilities Related Demand - \$/kW Summer 0.00 0.00 0.00 0.00	Demand Char	ge - \$/kW					5.49	0.00	5.49	
Energy Charge - \$/kWh Summer Season On-Peak Mid-peak Off-Peak Off-Peak Winter Season Mid-peak Off-Peak	Power Factor Adjustment	- \$/kVA					0.27	0.00	0.27	
Energy Charge - \$/kWh Summer Season On-Peak Mid-peak Off-Peak Off-Peak Winter Season Mid-peak Off-Peak	TOUR (Above 50 kV) Ontion B									
Summer Season On-Peak On-Peak On-Peak On-Peak On-Peak On-Peak On-Peak On-Peak On-Peak On-Peak On-Peak On-Peak On-Peak On-Peak On-Peak On-Peak On-Peak On-Peak On-Peak On-Neak										
Mid-peak 0.01309 0.10047 0.11356 Off-Peak 0.01309 0.04571 0.05880 Off-Peak 0.01309 0.04571 0.05880 Off-Peak 0.01309 0.04571 0.05880 Off-Peak 0.01309 0.04571 0.05880 Off-Peak 0.01309 0.04539 0.05848 Off-Peak 0.01309 0.05848	3, 4 4 34 4	Summer Season								
Off-Peak 0.01309 0.04571 0.05880 Winter Season Mid-peak 0.01309 0.06391 0.07700 0.05848 Customer Charge - \$/month 2183.50 0.05848 Customer Charge - \$/month 2183.50 0.00 2183.50 Facilities Related Demand Charge - \$/kW 3.06 0.00 3.06 Power Factor Adjustment - \$/kVA 0.32 0.00 0.32 Voltage Discount, 220 kV and above Facilities Related Demand - \$/kW 1 mere Related Demand - \$/kW		On-Peak					0.01309	0.26116	0.27425	
Winter Season Mid-peak 0.01309 0.06391 0.07700 0.07700 0.07700 0.07901 0.07700 0.07901										
Mid-peak Off-Peak 0.01309 0.06391 0.07700 0.01309 0.04539 0.05848 0.07700 0.01309 0.04539 0.05848 0.07700 0.01309 0.04539 0.05848 0.07700 0.01309 0.04539 0.05848 0.07700 0.05848 0.07700 0.07						1	0.01309	0.04571	0.05880	
Off-Peak 0.01309 0.04539 0.05848 Customer Charge - \$/month 2183.50 0.00 2183.50 Facilities Related 3.06 0.00 3.06 Demand Charge - \$/kW 0.32 0.00 0.32 Voltage Discount, 220 kV and above 5.6 clilities Related Demand - \$/kW -1.00 0.00 -1.00 Time-Related Demand - \$/kW 0.00 0.00 0.00 0.00							าการกด	0.06391	0.07700	
Facilities Related Demand Charge - \$/kW 3.06 0.00 3.06 Power Factor Adjustment - \$/kVA 0.32 0.00 0.32 Voltage Discount, 220 kV and above Facilities Related Demand - \$/kW -1.00 0.00 -1.00 Time-Related Demand - \$/kW Summer 0.00 0.00 0.00										
Facilities Related Demand Charge - \$/kW 3.06 0.00 3.06 Power Factor Adjustment - \$/kVA 0.32 0.00 0.32 Voltage Discount, 220 kV and above Facilities Related Demand - \$/kW -1.00 0.00 -1.00 Time-Related Demand - \$/kW Summer 0.00 0.00 0.00										
Demand Charge - \$/kW 3.06 0.00 3.06 Power Factor Adjustment - \$/kVA 0.32 0.00 0.32 Voltage Discount, 220 kV and above Facilities Related Demand - \$/kW Time-Related Demand - \$/kW Summer -1.00 0.00 -1.00 Summer 0.00 0.00 0.00 0.00		nth					2183.50	0.00	2183.50	
Power Factor Adjustment - \$/kVA 0.32 0.00 0.32 Voltage Discount, 220 kV and above Facilities Related Demand - \$/kW -1.00 0.00 -1.00 Time-Related Demand - \$/kW Summer 0.00 0.00 0.00		ao - \$/k\N					3.06	0.00	3.06	
Voltage Discount, 220 kV and above	Demand Char	Ac Alvan					3.00	0.00	3.06	
Facilities Related Demand - \$/kW	Power Factor Adjustment	- \$/kVA					0.32	0.00	0.32	
Time-Related Demand - \$/kW Summer 0.00 0.00 0.00	Voltage Discount, 220 kV	and above								
Summer 0.00 0.00 0.00							-1.00	0.00	-1.00	
			\$/kW							
Energy - \$7KVVN 0.00000 -0.00064 (0.00064)										
		⊏⊓ergy - ⊅/KWn				1	0.0000	-u.00064	(0.00064)	

		Rates Ef	fective Decen	nber 2008	Proposed Rat	es Effective C	October 1, 2009	_
differentia aggregate	idential rates based on seven cent Tier 3 - Tier 5 l and baseline allocations set at 55% of average usage by CEC climate zone, assuming modification of provided in Paragraph 4.bii and 4.bv. CIA adjustment							Т
	emented effective with rate changes made in 2010 for	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	
PA-1	Energy Charge - \$/kWh	0.02559	0.10973	0.13532	0.03306	0.10163	0.13469	
	Customer Charge - \$/month	30.02	0.00	30.02	40.80	0.00	40.80	
	Service Charge - \$/hp	2.23	0.00	2.23	1.95	0.00	1.95	
	Off Peak Credit - \$/hp	(2.01)	0.00	(2.01)	0.00	(1.72)	(1.72)	
	Voltage Discount, Energy - \$/kWh From 2 kV to 50 kV From 51 kV to 219 kV 220 kV and above	0.00000 0.00000	(0.00199) (0.00433)	(0.00199) (0.00433)	0.00000 0.00000 0.00000	(0.00468)	(0.00210) (0.00468) (0.00473)	
	Voltage Discount, Connected Load - \$/Hp From 2 kV to 50 kV From 51 kV to 219 kV 220 kV and above	(0.14) (4.66)	0.00 0.00	(0.14) (4.66)	(0.03) (0.95) (0.96)		(0.03) (0.95) (0.96)	
PA-2								
	Energy Charge - \$/kWh Summer Winter	0.01551 0.01551	0.07351 0.07171	0.08902 0.08722	0.01225 0.01225		0.11557 0.07430	
	Customer Charge - \$/month	58.91	0.00	58.91	80.04	0.00	80.04	
	Demand Charge - \$/kW	8.83	0.00	8.83	7.26	0.00	7.26	
	Time Related Demand Charge - \$/kW Summer Season	0.00	0.00	0.00	0.00	3.50	3.50	
	Winter Season TOU Option Meter Charge - \$/month	0.00	0.00	0.00	0.00	0.00	0.00	
	TOU-RTEM Voltage Discount, Facilities Related Demand - \$/kW	158.83	0.00	158.83	86.55	0.00	86.55	
	From 2 kV to 50 kV From 51 kV to 219 kV 220 kV and above	(0.19) (6.25)	0.00 0.00	(0.19) (6.25)	(0.09) (2.98) (6.18)	0.00	(0.09) (2.98) (6.18)	
	Voltage Discount, Time-Related Demand - \$/kW From 2 kV to 50 kV From 51 kV to 219 kV 220 kV and above	0.00 0.00	0.00 0.00	0.00 0.00	0.00 0.00 0.00	(0.35) (0.96) (0.97)	(0.35) (0.96) (0.97)	
	Voltage Discount, Energy - \$/kWh	0.00000	(0.00400)	(0.00400)				
	From 2 kV to 50 kV From 51 kV to 219 kV 220 kV and above	0.00000 0.00000	(0.00199) (0.00433)	(0.00199) (0.00433)	0.00000 0.00000 0.00000	(0.00312)	(0.00140) (0.00312) (0.00316)	
A-RTP	Energy Charge - \$/kWh	0.01356		Variable*	0.01152	Variable*	Variable*	
	Customer Charge - \$/month	83.73	0.00	83.73	113.76	0.00	113.76	
	Facilities Related Demand Charge - \$/kW	4.46	0.00	4.46	7.05	0.00	7.05	
	Voltage Discount, Hourly Rates - %							
	From 2 kV to 50 kV above 50 kV Voltage Discount, Facilities Related Demand - \$/kW From 2 kV to 50 kV From 51 kV to 219 kV	0.00% 0.00%	-2.38% -5.19%	-2.38% -5.19%	0.00% 0.00% (0.10) (3.04)		-2.39% -5.32% (0.10) (3.04)	
	220 kV and above				(6.09)		(6.09)	
	Power Factor Adjustment - \$/kVA Greater than 50 kV 50 kV or less	0.20 0.18	0.00 0.00	0.20 0.18	0.32 0.27	0.00 0.00	0.32 0.27	
See RTP	Schedules for PA-RTP.							
ΓΟU-PA (Rate A)							
	Energy Charge - \$/kWh Summer Season							
	On-Peak Mid-peak Off-Peak	0.01356 0.01356 0.01356	0.10204 0.08615 0.03509	0.11560 0.09971 0.04865	0.01152 0.01152 0.01152	0.08689	0.20000 0.09841 0.05678	
	Winter Season Mid-peak Off-Peak	0.01356 0.01356	0.09745 0.03509	0.11101 0.04865	0.01152 0.01152		0.08757 0.05529	
	Customer Charge - \$/month	83.73	0.00	83.73	113.76	0.00	113.76	
	Service Charge - \$/hp	3.75	1.03	4.78	5.28	0.00	5.28	
	Voltage Discount, Energy - \$/kWh From 2 kV to 50 kV From 51 kV to 219 kV 220 kV and above	0.00000 0.00000	(0.00199) (0.00432)	(0.00199) (0.00432)	0.00000 0.00000 0.00000	(0.00294)	(0.00132) (0.00294) (0.00298)	
	Voltage Discount, Connected Load - \$/Hp From 2 kV to 50 kV From 51 kV to 219 kV	(0.14) (4.68)	0.00	(0.14) (4.68)	(0.07) (2.28)		(0.07) (2.28)	

	Rates Ef	fective Decen	nber 2008	Proposed Ra	tes Effective C	october 1, 2009	
Note: Residential rates based on seven cent Tier 3 - Tier 5 differential and baseline allocations set at 55% of average							
aggregate usage by CEC climate zone, assuming modification of							
AB1X as provided in Paragraph 4.b.iii and 4.b.v. CIA adjustment	5 "						Total Rate
to be implemented effective with rate changes made in 2010 for	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Change
TOU-PA (Rate B)							
Energy Charge - \$/kWh							
Summer Season							
On-Peak	0.01356	0.09989	0.11345	0.0115		0.10950	-3.48%
Mid-peak Off-Peak	0.01356 0.01356	0.08224 0.03510	0.09580 0.04866	0.0115 0.0115		0.07538 0.05680	-21.32% 16.73%
Winter Season	0.01356	0.03510	0.04866	0.0115.	2 0.04528	0.05680	10.73%
Mid-peak	0.01356	0.09320	0.10676	0.0115	0.06345	0.07497	-29.78%
Off-Peak	0.01356	0.03510	0.04866	0.0115		0.05530	13.65%
Customer Charge - \$/month	83.73	0.00	83.73	113.76	0.00	113.76	35.87%
Facilities Related Demand Charge - \$/kW	5.01	0.00	5.01	7.05	0.00	7.05	40.72%
Time Related Demand Charge - \$/kW	3.01	0.00	3.01	7.00	0.00	7.03	40.7276
Summer Season							
On-Peak	0.00	9.77	9.77	0.00	10.65	10.65	9.01%
Mid-Peak	0.00	0.00	0.00	0.00	2.54	2.54	
Voltage Discount Facilities Balated Bernard Annua							
Voltage Discount, Facilities Related Demand - \$/kW From 2 kV to 50 kV	(0.19)	0.00	(0.19)	(0.10	0.00	(0.10)	47.37%
From 51 kV to 219 kV	(6.25)	0.00	(6.25)	(3.04	•	(3.04)	51.36%
220 kV and above	(0.20)	0.00	(0.20)	(6.09		(6.09)	31.3070
Voltage Discount, Time-Related Demand - \$/kW							
From 2 kV to 50 kV	0.00	(0.39)	(0.39)	0.00	(0.19)	(0.19)	51.28%
From 51 kV to 219 kV	0.00	(1.04)	(1.04)	0.00		(0.54)	48.08%
220 kV and above				0.00	(0.55)	(0.55)	
Voltage Discount, Energy - \$/kWh From 2 kV to 50 kV	0.00000	(0.00199)	(0.00199)	0.0000	(0.00132)	(0.00132)	33.62%
From 51 kV to 219 kV	0.00000	(0.00133)	(0.00133)	0.0000		(0.00132)	31.92%
220 kV and above		()	(/	0.0000		(0.00298)	
TOU-PA (Both Options)							
Power Factor Adjustment - \$/kVA Greater than 50 kV	0.20	0.00	0.20	0.32	0.00	0.32	60.00%
50 kV or less	0.20	0.00	0.20	0.32	0.00	0.32	50.00%
33 10 00	0.10	0.00	0.10	0.21	0.00	0.21	00.0070
TOU-PA-CPP							
Critical Peak Pricing							
Energy Charge - \$/kWh							
Summer Season On-Peak	0.01356	0.09162	0.10518	0.0115	0.09798	0.10950	4.11%
Mid-peak	0.01356	0.03102	0.08878	0.0115		0.07538	-15.09%
Off-Peak	0.01356	0.03510	0.04866	0.0115		0.05680	16.73%
Winter Season							
Mid-peak	0.01356	0.08540	0.09896	0.0115	0.06345	0.07497	-24.24%
Off-Peak	0.01356	0.03510	0.04866	0.0115	0.04378	0.05530	13.65%
Ourteman Observe Chromath	00.70	0.00	00.70	440.70	0.00	440.70	25.070/
Customer Charge - \$/month Facilities Related	83.73	0.00	83.73	113.76	0.00	113.76	35.87%
Demand Charge - \$/kW	5.01	0.00	5.01	7.05	0.00	7.05	40.72%
Time Related Demand Charge - \$/kW		· · ·			· · ·	·-	. =
Summer Season							
On-Peak	0.00	9.77	9.77	0.00		10.65	9.01%
Mid-Peak	0.00	0.00	0.00	0.00	2.54	2.54	
Voltage Discount, Facilities Related Demand - \$/kW							
From 2 kV to 50 kV	(0.19)	0.00	(0.19)	(0.10	0.00	(0.10)	47.37%
From 51 kV to 219 kV	(6.25)	0.00	(6.25)	(3.04	•	(3.04)	51.36%
220 kV and above				(6.09	0.00	(6.09)	
Voltage Discount, Time-Related Demand - \$/kW							
From 2 kV to 50 kV	0.00	(0.39)	(0.39)	0.00		(0.19)	51.28%
From 51 kV to 219 kV	0.00	(1.04)	(1.04)	0.00		(0.54)	48.08%
220 kV and above Voltage Discount, Energy - \$/kWh				0.00	(0.55)	(0.55)	
From 2 kV to 50 kV	0.00000	(0.00199)	(0.00199)	0.0000	(0.00132)	(0.00132)	33.62%
From 51 kV to 219 kV	0.00000	(0.00432)	(0.00432)	0.0000		(0.00294)	31.92%
220 kV and above		,		0.0000		(0.00298)	
Power Factor Adjustment - \$/kVA							
Greater than 50 kV	0.20	0.00	0.20	0.32		0.32	60.00%
50 kV or less	0.18	0.00	0.18	0.27		0.27	50.00%
CPP Event Energy Charge - \$kWh Summer CPP Non-Event Credit				0.0000	1.36229	1.36229	
On-Peak Demand Credit - \$kWh				0.00	(8.69)	(8.69)	
				5.00	(2.50)	(0)	

	Rates Effe	ective Decen	nber 2008	E	roposed Rate	es Effective O	ctober 1, 2009	
Note: Residential rates based on seven cent Tier 3 - Tier 5								
differential and baseline allocations set at 55% of average								
aggregate usage by CEC climate zone, assuming modification of AB1X as provided in Paragraph 4.b.iii and 4.b.v. CIA adjustment								Total Rate
to be implemented effective with rate changes made in 2010 for	Delivery	Generation	Total Rate		Delivery	Generation	Total Rate	Change
TOU-PA-5								
Energy Charge - \$/kWh								
Summer Season On-Peak	0.01362	0.06646	0.08008		0.01166	0.09448	0.10614	32.54%
Mid-peak	0.01362	0.05368	0.06730		0.01166	0.06440	0.07606	13.02%
Off-Peak	0.01362	0.03173	0.04535		0.01166	0.04174	0.05340	17.75%
Winter Season Mid-peak	0.01362	0.05666	0.07028		0.01166	0.05611	0.06777	-3.57%
Off-Peak	0.01362	0.03352	0.07020		0.01166	0.03959	0.05125	8.72%
Customer Charge - \$/month	85.06	0.00	85.06		115.57	0.00	115.57	35.87%
Minimum Charge - \$/kW Summer Season	9.94	29.46	39.40		10.68	29.46	40.14	1.88%
Winter Season	8.42	11.99	20.41		9.16	11.99	21.15	3.63%
Facilities Related								
Demand Charge - \$/kW Time Related Demand Charge - \$/kW	9.95	0.00	9.95		9.79	0.00	9.79	-1.61%
Summer Season								
On-Peak	0.00	10.49	10.49		0.00	14.25	14.25	35.84%
Mid-Peak	0.00	0.00	0.00		0.00	4.00	4.00	
Winter Season								
Mid-Peak	0.00				0.00	0.00	0.00	
Off-Peak	0.00				0.00	0.00	0.00	
5								
Power Factor Adjustment - \$/kVA Greater than 50 kV	0.20	0.00	0.20		0.32	0.00	0.32	60.00%
50 kV or less	0.18	0.00	0.18		0.27	0.00	0.27	50.00%
Voltage Discount, Facilities Related Demand - \$/kW From 2 kV to 50 kV	(0.19)	0.00	(0.19)		(0.14)	0.00	(0.14)	26.32%
From 51 kV to 219 kV	(6.24)	0.00	(6.24)		(4.50)	0.00	(4.50)	27.88%
220 kV and above	()		· · · · · ·		(7.76)	0.00	(7.76)	
Voltage Discount, Time-Related Demand - \$/kW	0.00	(0.00)	(0.00)		0.00	(0.04)	(0.04)	00.540/
From 2 kV to 50 kV From 51 kV to 219 kV	0.00 0.00	(0.39) (1.04)	(0.39) (1.04)		0.00 0.00	(0.31) (0.86)	(0.31) (0.86)	20.51% 17.31%
220 kV and above	0.00	(1.04)	(1.04)		0.00	(0.87)	(0.87)	17.5170
Voltage Discount, Energy - \$/kWh								
From 2 kV to 50 kV From 51 kV to 219 kV	0.00000	(0.00199) (0.00432)	(0.00199) (0.00432)		0.00000	(0.00134) (0.00299)	(0.00134) (0.00299)	32.54% 30.81%
220 kV and above	0.00000	(0.00432)	(0.00432)		0.00000	(0.00299)	(0.00299)	30.61%
						(, , , , , ,	(, , , , ,	
TOU-PA-ICE								
Energy Charge - \$/kWh Summer Season								
On-Peak	0.01885	0.13670	0.15555		0.01647	0.14141	0.15788	1.50%
Mid-peak	0.01885	0.07425	0.09310		0.01647	0.07803	0.09450	1.50%
Off-Peak	0.01885	0.02293	0.04178		0.01647	0.02594	0.04241	1.51%
Winter Season Mid-peak	0.01885	0.09385	0.11270		0.01647	0.09792	0.11439	1.50%
Off-Peak	0.01885	0.02293	0.04178		0.01647	0.02594	0.04241	1.51%
Customer Charge - \$/month Facilities Related	50.14	0.00	50.14		50.89	0.00	50.89	1.50%
Demand Charge - \$/kW	3.02	0.00	3.02		3.07	0.00	3.07	1.66%
Time Related Demand Charge - \$/kW								
Summer Season								
On-Peak Mid-Peak	1.09 0.00	0.05 0.00	1.14 0.00		1.09 0.00	0.07 0.00	1.16 0.00	1.75%
ind i dak	0.00	0.00	0.00		0.00	0.00	0.00	
Voltage Discount, Facilities Related Demand - \$/kW								
From 2 kV to 50 kV From 51 kV to 219 kV	(0.10)	0.00	(0.10)		(0.10)	0.00	(0.10)	0.00%
220 kV and above	(2.39)	0.00	(2.39)		(2.39) 0.00	0.00	(2.39) 0.00	0.00%
Voltage Discount, Time-Related Demand - \$/kW								
From 2 kV to 50 kV	(0.18)	0.00	(0.18)		(0.18)	0.00	(0.18)	0.00%
From 51 kV to 219 kV 220 kV and above	(1.09)	0.00	(1.09)		(1.09) 0.00	0.00	(1.09) 0.00	0.00%
Voltage Discount, Energy - \$/kWh					0.00	0.00	0.00	
From 2 kV to 50 kV	0.00000	(0.00068)	(0.00068)		0.00000	(0.00068)	(0.00068)	0.00%
From 51 kV to 219 kV	0.00000	(0.00145)	(0.00145)		0.00000	(0.00145)	(0.00145)	0.00%
220 kV and above					0.00000	0.00000	0.00000	
Power Factor Adjustment - \$/kVA								
Greater than 50 kV	0.20	0.00	0.20		0.20	0.00	0.20	0.00%
50 kV or less	0.18	0.00	0.18		0.18	0.00	0.18	0.00%

	Rates Eff	ective Decen	nber 2008	P	roposed Rate	es Effective O	ctober 1, 2009	
ote: Residential rates based on seven cent Tier 3 - Tier 5								
fferential and baseline allocations set at 55% of average								
ggregate usage by CEC climate zone, assuming modification of								Total Ra
B1X as provided in Paragraph 4.b.iii and 4.b.v. CIA adjustment be implemented effective with rate changes made in 2010 for	Delivery	Generation	Total Rate		Delivery	Generation	Total Rate	Chang
be implemented effective with rate changes made in 2010 for	Delivery	Generation	Total Rate	L	Delivery	Generation	Total Rate	Chang
DU-PA-SOP								
Energy Charge - \$/kWh								
Summer Season								
On-Peak	0.01356	0.08150	0.09506		0.01152	0.07996	0.09148	-3.7
Off-peak	0.01356	0.05672	0.07028		0.01152	0.05491	0.06643	-5.4
Super Off-Peak	0.01356	0.03404	0.04760		0.01152	0.03287	0.04439	-6.74
Winter Season								
Off-peak	0.01356	0.05689	0.07045		0.01152	0.06289	0.07441	5.62
Super Off-Peak	0.01356	0.03368	0.04724		0.01152	0.03251	0.04403	-6.8
Customer Charge - \$/month	83.73	0.00	83.73		113.76	0.00	113.76	35.8
Facilities Related	63.73	0.00	03.73		113.76	0.00	113.76	33.0
Demand Charge - \$/kW	5.01	0.00	5.01		7.05	0.00	7.05	40.72
Time Related Demand Charge - \$/kW	5.01	0.00	5.01		7.05	0.00	7.05	40.7
Summer Season								
On-Peak	0.00	18.56	18.56		0.00	24.44	24.44	31.6
Off-Peak	0.00	0.00	0.00		0.00	0.00	0.00	31.0
On-1 care	0.00	0.00	0.00		0.00	0.00	0.00	
Winter Season								
Off-Peak	0.00				0.00	0.00	0.00	
Super Off-Peak	0.00				0.00	0.00	0.00	
Other Charges								
Power Factor Adjustment - \$/kVA								
Greater than 50 kV	0.20	0.00	0.20		0.32	0.00	0.32	60.0
50 kV or less	0.18	0.00	0.18		0.27	0.00	0.27	50.00
Voltage Discount, Facilities Related Demand - \$/kW								
From 2 kV to 50 kV	(0.19)	0.00	(0.19)		(0.10)	0.00	(0.10)	47.3
From 51 kV to 219 kV	(6.25)	0.00	(6.25)		(3.04)	0.00	(3.04)	51.3
220 kV and above					(6.09)	0.00	(6.09)	
Voltage Discount, Time-Related Demand - \$/kW								
From 2 kV to 50 kV	0.00	(0.39)	(0.39)		0.00	(0.19)	(0.19)	51.2
From 51 kV to 219 kV	0.00	(1.04)	(1.04)		0.00	(0.54)	(0.54)	48.0
220 kV and above					0.00	(0.55)	(0.55)	
Voltage Discount, Energy - \$/kWh								
From 2 kV to 50 kV	0.00000	(0.00199)	(0.00199)		0.00000	(0.00132)	(0.00132)	33.6
From 51 kV to 219 kV	0.00000	(0.00432)	(0.00432)		0.00000	(0.00294)	(0.00294)	31.9
220 kV and above					0.00000	(0.00298)	(0.00298)	
2-1								
Interruptible Credit								
\$/kWh	(0.00933)	0.00000	(0.00933)		(0.01164)	0.00000	(0.01164)	-24.7
BIP Option Credit (\$/KW)								
Summer On Peak					(17.22)	0.00	(17.22)	
					(2.66)	0.00	(2.66)	
Summer Mid - Peak					(3.66)	0.00	(3.66)	

Note: Pos		Rates Eff	ective Decen	nber 2008	Proposed Ra	tes Effective C	october 1, 2009	
Note: Das								
	sidential rates based on seven cent Tier 3 - Tier 5							
aggregate	usage by CEC climate zone, assuming modification of							T-4-11
	provided in Paragraph 4.b.iii and 4.b.v. CIA adjustment lemented effective with rate changes made in 2010 for	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Total I Char
AL-2		,						
	Option A	0.01959	0.06018	0.07977	0.0165	2 0.05537	0.07189	-9
	Energy Charge - \$/kWh	0.01939	0.00016	0.07977	0.0165	2 0.05557	0.07109	-9
	Option B							
	Energy Charge - \$/kWh Summer Season							
	On-Peak				0.0504	4 0.12875	0.17919	
	Off-Peak				0.0165	2 0.05537	0.07189	
	Winter Season On-Peak				0.0504	4 0.07875	0.12919	
	Off-Peak				0.0165		0.07189	
	Both Options Customer Charge - \$/month	9.27	0.00	9.27	14.00	0.00	14.00	51
	Customer Charge - \$/month	5.21	0.00	5.21	14.00	0.00	14.00	31
WL								
	Energy Charge - \$/kWh Rate A - Other Charges	0.02442	0.06018	0.08460	0.0239	0.05537	0.07933	-6
	High Pressure Sodium Vapor Lamp - \$/lamp	/month						
	50 Watt	7.44	0.00	7.44	8.43		8.43	13
	70 Watt 100 Watt	7.52	0.00	7.52	8.52		8.52	13
	150 Watt	7.91 7.91	0.00	7.91 7.91	8.96 8.96		8.96 8.96	13 13
	Metal Halide Lamp - \$/lamp/month	7.01	0.00	7.01	0.00	0.00	0.00	
	100 Watt	13.89	0.00	13.89	15.73		15.73	13
	175 Watt Mercury Vapor Lamp - \$/lamp/month	12.76	0.00	12.76	14.45	0.00	14.45	13
	75 Watt	7.57	0.00	7.57	8.58	0.00	8.58	13
	Rate B - Other Charges							
	High Pressure Sodium Vapor Lamp - \$/lamp							
	50 Watt 70 Watt	7.44 7.52	0.00	7.44 7.52	8.43 8.52		8.43 8.52	13 13
	100 Watt	7.91	0.00	7.91	8.96		8.96	13
	150 Watt	7.91	0.00	7.91	8.96	0.00	8.96	13
	Metal Halide Lamp - \$/lamp/month 100 Watt	13.89	0.00	13.89	15.73	0.00	15.73	13
	175 Watt	12.76	0.00	12.76	14.45		14.45	13
	Mercury Vapor Lamp - \$/lamp/month							
	75 Watt	3.40	0.00	3.40	3.85	0.00	3.85	13
	Rate C - Other Charges							
	High Pressure Sodium Vapor Lamp - \$/lamp	/month						
	50 Watt	0.51	0.00	0.51	0.58		0.58	13
	70 Watt 100 Watt	0.51 0.51	0.00	0.51 0.51	0.58 0.58		0.58 0.58	13
	150 Watt	0.51	0.00	0.51	0.58		0.58	13 13
	Metal Halide Lamp - \$/lamp/month							
	100 Watt	1.96	0.00	1.96	2.22		2.22	13
	175 Watt Mercury Vapor Lamp - \$/lamp/month	1.74	0.00	1.74	1.97	0.00	1.97	13
	75 Watt	0.53	0.00	0.53	0.60	0.00	0.60	13
	Minimum Charge - \$/month							
	Rate A Rate B	100.00 50.00	0.00	100.00 50.00	100.00 50.00		100.00 50.00	0
	<u>Kale B</u>	30.00	0.00	30.00	30.00	0.00	30.00	,
6-1								
	Energy Charge - \$/kWh	0.02442	0.06018	0.08460	0.0239	0.05537	0.07933	-6
	All Night Service Midnight Service	0.02442	0.06018	0.08460	0.0239		0.07933	-c -6
	• •							
	Other Charges - All Night/Midnight Service							
	Incandescent Lamps - \$/lamp/month 103 Watt	8.45	0.00	8.45	9.56	0.00	9.56	13
	202 Watt	8.49	0.00	8.49	9.61		9.61	13
		0.04	0.00	8.61	9.75		9.75	13
	327 Watt	8.61			10.27	0.00	10.27	13
	448 Watt	9.07	0.00	9.07				
	448 Watt Mercury Vapor Lamps - \$/lamp/month	9.07			8.70	0.00	8.70	15
	448 Watt		0.00 0.00 0.00	7.69 7.73	8.70 8.75		8.70 8.75	
	448 Watt Mercury Vapor Lamps - \$flamp/month 100 Watt 175 Watt 250 Watt	9.07 7.69 7.73 8.26	0.00 0.00 0.00	7.69 7.73 8.26	8.75 9.35	0.00 0.00	8.75 9.35	10 10
	448 Watt Mercury Vapor Lamps - \$/lamp/month 100 Watt 175 Watt 250 Watt 400 Watt	9.07 7.69 7.73 8.26 8.70	0.00 0.00 0.00 0.00	7.69 7.73 8.26 8.70	8.75 9.35 9.85	0.00 0.00 0.00	8.75 9.35 9.85	10 10 10
	448 Watt Mercury Vapor Lamps - \$flamp/month 100 Watt 175 Watt 250 Watt	9.07 7.69 7.73 8.26	0.00 0.00 0.00	7.69 7.73 8.26	8.75 9.35	0.00 0.00 0.00 0.00	8.75 9.35	10 10 10 10
	448 Watt Mercury Vapor Lamps - \$/lamp/month 100 Watt 175 Watt 250 Watt 400 Watt 700 Watt 1,000 Watt High Pressure Sodium Vapor Lamps - \$/lam	9.07 7.69 7.73 8.26 8.70 9.80 9.45	0.00 0.00 0.00 0.00 0.00 0.00	7.69 7.73 8.26 8.70 9.80 9.45	8.75 9.35 9.85 11.10 10.70	0.00 0.00 0.00 0.00 0.00	8.75 9.35 9.85 11.10 10.70	10 10 10 10 10
	448 Watt Mercury Vapor Lamps - \$/lamp/month 100 Watt 175 Watt 250 Watt 400 Watt 700 Watt 1,000 Watt High Pressure Sodium Vapor Lamps - \$/lam 50 Watt	9.07 7.69 7.73 8.26 8.70 9.80 9.45 p/month 7.66	0.00 0.00 0.00 0.00 0.00 0.00	7.69 7.73 8.26 8.70 9.80 9.45	8.75 9.35 9.85 11.10 10.70	0.00 0.00 0.00 0.00 0.00	8.75 9.35 9.85 11.10 10.70	10 10 10 10 10 10
	448 Watt Mercury Vapor Lamps - \$/lamp/month 100 Watt 175 Watt 250 Watt 400 Watt 700 Watt 1,000 Watt 1,000 Watt High Pressure Sodium Vapor Lamps - \$/lam 50 Watt 70 Watt	9.07 7.69 7.73 8.26 8.70 9.80 9.45 p/month 7.66 7.75	0.00 0.00 0.00 0.00 0.00 0.00 0.00	7.69 7.73 8.26 8.70 9.80 9.45 7.66 7.75	8.75 9.35 9.85 11.10 10.70 8.67 8.77	0.00 0.00 0.00 0.00 0.00 0.00	8.75 9.35 9.85 11.10 10.70 8.67 8.77	10 13 10 10 10 10 11
	448 Watt Mercury Vapor Lamps - \$/lamp/month 100 Watt 175 Watt 250 Watt 400 Watt 700 Watt 1,000 Watt High Pressure Sodium Vapor Lamps - \$/lam 50 Watt	9.07 7.69 7.73 8.26 8.70 9.80 9.45 p/month 7.66	0.00 0.00 0.00 0.00 0.00 0.00	7.69 7.73 8.26 8.70 9.80 9.45	8.75 9.35 9.85 11.10 10.70	0.00 0.00 0.00 0.00 0.00 0.00 0.00	8.75 9.35 9.85 11.10 10.70	10 10 10 10 10 10 11 11
	448 Watt Mercury Vapor Lamps - \$/lamp/month 100 Watt 175 Watt 250 Watt 400 Watt 700 Watt 1,000 Watt 1,000 Watt High Pressure Sodium Vapor Lamps - \$/lam 50 Watt 100 Watt 150 Watt 250 Watt	9.07 7.69 7.73 8.26 8.70 9.80 9.45 p/month 7.66 7.75 8.16 8.16 8.70	0.00 0.00 0.00 0.00 0.00 0.00 0.00 0.0	7.69 7.73 8.26 8.70 9.80 9.45 7.66 7.75 8.16 8.16	8.75 9.35 9.85 11.10 10.70 8.67 8.77 9.24 9.24 9.85	0.00 0.00 0.00 0.00 0.00 0.00 0.00 0.0	8.75 9.35 9.85 11.10 10.70 8.67 9.24 9.24 9.85	1: 1: 1: 1: 1: 1: 1: 1:
	448 Watt Mercury Vapor Lamps - \$/lamp/month 100 Watt 175 Watt 250 Watt 400 Watt 700 Watt 1,000 Watt 1,000 Watt High Pressure Sodium Vapor Lamps - \$/lam 50 Watt 70 Watt 100 Watt 150 Watt 250 Watt	9.07 7.69 7.73 8.26 8.70 9.80 9.45 p/month 7.66 7.75 8.16 8.16 8.70 8.77	0.00 0.00 0.00 0.00 0.00 0.00 0.00 0.0	7.69 7.73 8.26 8.70 9.80 9.45 7.66 7.75 8.16 8.16 8.70 8.77	8.75 9.35 9.85 11.10 10.70 8.67 8.77 9.24 9.24 9.85 9.94	0.00 0.00 0.00 0.00 0.00 0.00 0.00 0.0	8.75 9.35 9.85 11.10 10.70 8.67 8.77 9.24 9.24 9.85 9.94	10 10 11 11 11 10 11 11 11 11
	448 Watt Mercury Vapor Lamps - \$/lamp/month 100 Watt 175 Watt 250 Watt 400 Watt 700 Watt 1,000 Watt High Pressure Sodium Vapor Lamps - \$/lam 50 Watt 70 Watt 100 Watt 150 Watt 150 Watt 250 Watt 250 Watt 400 Watt	9.07 7.69 7.73 8.26 8.70 9.80 9.45 6/month 7.66 7.76 8.16 8.16 8.70 8.77 9.15	0.00 0.00 0.00 0.00 0.00 0.00 0.00 0.0	7.69 7.73 8.26 8.70 9.80 9.45 7.66 7.75 8.16 8.16	8.75 9.35 9.85 11.10 10.70 8.67 8.77 9.24 9.24 9.85	0.00 0.00 0.00 0.00 0.00 0.00 0.00 0.0	8.75 9.35 9.85 11.10 10.70 8.67 9.24 9.24 9.85	10 10 11 11 11 10 11 11 11 11
	448 Watt Mercury Vapor Lamps - \$/lamp/month 100 Watt 175 Watt 250 Watt 400 Watt 700 Watt 1,000 Watt 1,000 Watt High Pressure Sodium Vapor Lamps - \$/lam 50 Watt 70 Watt 100 Watt 150 Watt 250 Watt	9.07 7.69 7.73 8.26 8.70 9.80 9.45 6/month 7.66 7.76 8.16 8.16 8.70 8.77 9.15	0.00 0.00 0.00 0.00 0.00 0.00 0.00 0.0	7.69 7.73 8.26 8.70 9.80 9.45 7.66 7.75 8.16 8.16 8.70 8.77	8.75 9.35 9.85 11.10 10.70 8.67 8.77 9.24 9.24 9.85 9.94	0.00 0.00 0.00 0.00 0.00 0.00 0.00 0.0	8.75 9.35 9.85 11.10 10.70 8.67 8.77 9.24 9.24 9.85 9.94	13 13 13 13 13 13 13 14 15 15
	448 Watt Mercury Vapor Lamps - \$/lamp/month 100 Watt 175 Watt 250 Watt 400 Watt 700 Watt 1,000 Watt 1,000 Watt High Pressure Sodium Vapor Lamps - \$/lam 50 Watt 70 Watt 100 Watt 150 Watt 200 Watt 200 Watt 250 Watt 400 Watt Low Pressure Sodium Vapor Lamps - \$/lamp 35 Watt	9.07 7.69 7.73 8.26 8.70 9.80 9.45 6/month 7.66 7.76 8.16 8.70 8.77 9.15 6/month	0.00 0.00 0.00 0.00 0.00 0.00 0.00 0.0	7.69 7.73 8.26 8.70 9.80 9.45 7.66 7.75 8.16 8.70 8.77 9.15	8.75 9.35 9.86 11.10 10.70 8.67 9.24 9.24 9.88 9.94 10.36	0.00 0.00 0.00 0.00 0.00 0.00 0.00 0.0	8.75 9.35 9.85 11.10 10.70 8.67 8.77 9.24 9.85 9.94 10.36 11.35 11.04	15 15 15 16 15 15 15 15 16 17 18 18
	448 Watt Mercury Vapor Lamps - \$/lamp/month 100 Watt 175 Watt 250 Watt 400 Watt 700 Watt 1,000 Watt 1,000 Watt High Pressure Sodium Vapor Lamps - \$/lam 50 Watt 70 Watt 100 Watt 150 Watt 200 Watt 250 Watt 400 Watt Low Pressure Sodium Vapor Lamps - \$/lam 35 Watt	9.07 7.69 7.73 8.26 8.70 9.80 9.45 p/month 7.66 6.7.75 8.16 8.16 8.70 9.15 p/month 10.03	0.00 0.00 0.00 0.00 0.00 0.00 0.00 0.0	7.69 7.73 8.26 8.70 9.80 9.45 7.66 7.75 8.16 8.16 8.70 8.77 9.15	8.75 9.35 9.86 11.10 10.70 8.67 9.24 9.24 9.85 9.94 10.36	0.00 0.00 0.00 0.00 0.00 0.00 0.00 0.0	8.75 9.35 9.85 11.10 10.70 8.67 8.77 9.24 9.24 9.85 9.94 10.36	13 13 15 13 13 13 15 15 15 15 15 15 15 15 15 15 15 15 15

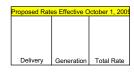
				Rates Et	fective Decer	nher 2008	Propo	sed Rate	es Effective C	October 1, 2009	
				tatos El	CCUVC DCCCI	IDCI 2000	Порс	Scu reac	23 Elicotive C	7CLODET 1, 2005	
	dential rates based on seven cent Tie and baseline allocations set at 55% of										
	usage by CEC climate zone, assumir										
	rovided in Paragraph 4.b.iii and 4.b.v mented effective with rate changes n			elivery	Concretion	Total Data		livery	Concretion	Total Bata	Total Rate Change
to be imple	inented effective with rate changes in	nade in 2010 loi		siivei y	Generation	Total Rate	1	ilivery	Generation	Total Rate	Change
LS-1 (Con											
	Other Charges - All Night/Midnigl Metal Halide Lamps - \$										
	Wotal Hallao Zampo 🔾	75 Watt		15.59	0.00	15.59		17.65	0.00	17.65	13.21%
		100 Watt		13.72	0.00	13.72		15.53	0.00	15.53	13.19%
		175 Watt 250 Watt		12.57 10.17	0.00	12.57 10.17		14.23 11.51	0.00	14.23 11.51	13.21% 13.18%
		400 Watt		9.70	0.00	9.70		10.98	0.00	10.98	13.20%
		1,000 Watt		13.13	0.00	13.13		14.87	0.00	14.87	13.25%
	Tap Device Annual Charge	1,500 Watt		19.22	0.00	19.22		21.76	0.00	21.76	13.22%
		\$/device		21.86	0.00	21.86		21.86	0.00	21.86	0.00%
LS-2											
L3-2	Energy Charge - \$/kWh										
		All Night Service		0.02442	0.06018	0.08460		0.02396	0.05537	0.07933	-6.23%
		Midnight Service	(0.02442	0.06018	0.08460		0.02396	0.05537	0.07933	-6.23%
	Multiple Service (Other Charges)										
	All Night/Midnight Service										
	Rate A Incandescent Extended	d Service Lamps									
		- \$/lamp/month		1.74	0.00	1.74		1.97	0.00	1.97	13.22%
	Mercury Vapor Lamps	©/ /		4 74	0.00	4.74		4.07	0.00	4.07	42.000/
	High Pressure Sodium	- \$/lamp/month Vapor Lamps - \$/	lamp/month	1.74	0.00	1.74		1.97	0.00	1.97	13.22%
		50 Watt	,	1.74	0.00	1.74		1.97	0.00	1.97	13.22%
		70 Watt		1.74	0.00	1.74		1.97	0.00	1.97	13.22%
		100 Watt 150 Watt		1.74 1.74	0.00	1.74 1.74		1.97 1.97	0.00	1.97 1.97	13.22% 13.22%
		200 Watt		1.74	0.00	1.74		1.97	0.00	1.97	13.22%
		250 Watt		1.74	0.00	1.74		1.97	0.00	1.97	13.22%
		310 Watt 400 Watt		1.74 1.74	0.00	1.74 1.74		1.97 1.97	0.00	1.97 1.97	13.22% 13.22%
	Low Pressure Sodium										
	Metal Halide Lamps	-\$/lamp/month		1.74	0.00	1.74		1.97	0.00	1.97	13.22%
	Wetai Hailde Lamps	-\$/lamp/month		1.74	0.00	1.74		1.97	0.00	1.97	13.22%
	All Other Lamps										
		-\$/lamp/month		1.74	0.00	1.74		1.97	0.00	1.97	13.22%
	Rate B										
	Incandescent Extended			0.50	0.00	2.50		4.05	0.00	4.05	42.420/
	Mercury Vapor Lamps	- \$/lamp/month		3.58	0.00	3.58		4.05	0.00	4.05	13.13%
		- \$/lamp/month		3.58	0.00	3.58		4.05	0.00	4.05	13.13%
	High Pressure Sodium	Vapor Lamps - \$/ 50 Watt	lamp/month	3.58	0.00	3.58		4.05	0.00	4.05	13.13%
		70 Watt		3.58	0.00	3.58		4.05	0.00	4.05	13.13%
		100 Watt		3.58	0.00	3.58		4.05	0.00	4.05	13.13%
		150 Watt 200 Watt		3.58 3.58	0.00	3.58 3.58		4.05 4.05	0.00	4.05 4.05	13.13% 13.13%
		250 Watt		3.58	0.00	3.58		4.05	0.00	4.05	13.13%
		310 Watt		3.58	0.00	3.58		4.05	0.00	4.05	13.13%
	Low Pressure Sodium	400 Watt		3.58	0.00	3.58		4.05	0.00	4.05	13.13%
	Low Flessure Socium	-\$/lamp/month		3.58	0.00	3.58		4.05	0.00	4.05	13.13%
	Metal Halide Lamps										
	All Other Lamps	-\$/lamp/month		3.58	0.00	3.58		4.05	0.00	4.05	13.13%
	All Other Earlips	-\$/lamp/month		3.58	0.00	3.58		4.05	0.00	4.05	13.13%
	Carian Camata-										
	Series Service Series Service Power Fabtor - \$/kV	'ar		0.18	0.00	0.18		0.27	0.00	0.27	50.00%
	All Night/Midnight Service Incandescent Extended	40									
	incandescent Extended	-\$/lamp/month		7.98	0.00	7.98		9.04	0.00	9.04	13.28%
	Mercury Vapor Lamps										
	High Pressure Sodium	-\$/lamp/month	lamn/month	7.98	0.00	7.98		9.04	0.00	9.04	13.28%
	riigii Fressure Souluiii	50 Watt	iamp/monu	7.98	0.00	7.98		9.04	0.00	9.04	13.28%
		70 Watt		7.98	0.00	7.98		9.04	0.00	9.04	13.28%
		100 Watt 150 Watt		7.98 7.98	0.00	7.98 7.98		9.04 9.04	0.00 0.00	9.04 9.04	13.28% 13.28%
		200 Watt		7.98	0.00	7.98		9.04	0.00	9.04	13.28%
		250 Watt	N/A				N/A				
		310 Watt 400 Watt	N/A N/A				N/A N/A				
	Low Pressure Sodium		IN/A				IN/A				
		-\$/lamp/month		7.98	0.00	7.98		9.04	0.00	9.04	13.28%
	Metal Halide Lamps	-\$/lamp/month	N/A				N/A				
	All Other Lamps										
		-\$/lamp/month		7.98	0.00	7.98		9.04	0.00	9.04	13.28%
	Series Service Voltage Discount, E	nergy - \$/kWh	C	0.00000	(0.00227)	(0.00227)		0.00000	(0.00164)	(0.00164)	27.58%

		Rates Eff	ective Decen	nber 2008	Proposed Rate	s Effective O	ctober 1, 2009	
	sidential rates based on seven cent Tier 3 - Tier 5 al and baseline allocations set at 55% of average							
	e usage by CEC climate zone, assuming modification of							
	provided in Paragraph 4.b.iii and 4.b.v. CIA adjustment							Tota
to be impl	elemented effective with rate changes made in 2010 for	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Ch
I S-2 Cor	ntinued - (Optional Service - Relamp)							
L3-2 C011	Incandescent Extended Service Lamps							
	-\$/lamp/month	N/A			N/A			
	Mercury Vapor Lamps							
	-\$/lamp/month	N/A			N/A			
	High Pressure Sodium Vapor Lamps - \$/lamp/month							
	50 Watt	0.45	0.00	0.45	0.51	0.00	0.51	
	70 Watt 100 Watt	0.45 0.45	0.00	0.45 0.45	0.51 0.51	0.00	0.51 0.51	
	150 Watt	0.45	0.00	0.45	0.51	0.00	0.51	
	200 Watt	0.46	0.00	0.46	0.52	0.00	0.52	
	250 Watt	0.46	0.00	0.46	0.52	0.00	0.52	
	310 Watt	N/A	0.00					
	400 Watt	0.47	0.00	0.47	0.53	0.00	0.53	
	Low Pressure Sodium Vapor Lamps							
	-\$/lamp/month	N/A	0.00	N/A	N/A			
	Metal Halide Lamps							
	-\$/lamp/month	N/A		N/A	N/A			
	All Other Lamps -\$/lamp/month	N/A		N/A	N/A			
	-\$/iamp/month	IN/A		N/A	IN/A			
.S-3								
	Energy Charge - \$/kWh	0.01960	0.06018	0.07978	0.01652	0.05537	0.07189	
	Customer Charge - \$/month							
	Multiple Service	9.27	0.00	9.27	14.00	0.00	14.00	
	Series Service	725.49	0.00	725.49	725.49	0.00	725.49	•
	Optional Relamp Service Charge (\$/lamp/month)							
	High Pressure Sodium Vapor Lamps							
	50 Watt 70 Watt	0.45	0.00	0.45 0.45	0.51	0.00 0.00	0.51 0.51	1
	100 Watt	0.45 0.45	0.00	0.45	0.51 0.51	0.00	0.51	
	150 Watt	0.45	0.00	0.45	0.51	0.00	0.51	
	200 Watt	0.46	0.00	0.46	0.52	0.00	0.52	
	250 Watt	0.46	0.00	0.46	0.52	0.00	0.52	
	400 Watt	0.47	0.00	0.47	0.53	0.00	0.53	
	Series Service							
	Voltage Discount, Energy - \$/kWh	0.00000	(0.00227)	(0.00227)	0.00000	(0.00164)	(0.00164)	2
L-1								
·L-1	Energy Charge - \$/kWh							
	All Night Service	0.02442	0.06018	0.08460	0.02396	0.05537	0.07933	
	Midnight Service	0.02442	0.06018	0.08460	0.02396	0.05537	0.07933	
	Pole Charge - \$/pole/month	4.66	0.00	4.66	5.28	0.00	5.28	•
	Other Charges - All Night/Midnight Service							
	Mercury Vapor Lamps - \$/lamp/month 175 Watt	6.06	0.00	6.06	6.86	0.00	6.86	
	400 Watt	6.67	0.00	6.67	7.56	0.00	7.56	
	High Pressure Sodium Vapor Lamps - \$/lam		0.00	0.01	7.00	0.00	7.00	
	50 Watt	5.98	0.00	5.98	6.77	0.00	6.77	
	70 Watt	6.06	0.00	6.06	6.86	0.00	6.86	
	100 Watt	6.06	0.00	6.06	6.86	0.00	6.86	
	150 Watt	6.06	0.00	6.06	6.86	0.00	6.86	
	200 Watt	6.67	0.00	6.67	7.56	0.00	7.56	
	250 Watt	6.78	0.00	6.78	7.67	0.00	7.67	
	400 Watt	7.19	0.00	7.19	8.14	0.00	8.14	•
	Low Pressure Sodium Vapor Lamps - \$/lam		0.00	7.05	2.7-	0.00	0.00	
	35 Watt 55 Watt	7.85	0.00	7.85	8.89	0.00	8.89	
	90 Watt	7.85 9.36	0.00	7.85	8.89	0.00	8.89	
	90 Watt 135 Watt	9.36	0.00 0.00	9.36 9.08	10.60 10.28	0.00	10.60 10.28	1
	180 Watt	9.22	0.00	9.00	10.43	0.00	10.28	
			2.30					
	Metal Halide Lamps - \$/lamp/month		0.00	6.57	7.44	0.00	7.44	
	Metal Halide Lamps - \$/lamp/month 70 Watt	6.57	0.00					
	70 Watt 100 Watt	6.57 7.20	0.00	7.20	8.15	0.00	8.15	
	70 Watt 100 Watt 175 Watt	7.20 6.29	0.00 0.00	6.29	7.13	0.00	7.13	1
	70 Watt 100 Watt 175 Watt 250 Watt	7.20 6.29 6.45	0.00 0.00 0.00	6.29 6.45	7.13 7.30	0.00 0.00	7.13 7.30	1 1
	70 Watt 100 Watt 175 Watt 250 Watt 400 Watt	7.20 6.29 6.45 6.79	0.00 0.00 0.00 0.00	6.29 6.45 6.79	7.13 7.30 7.68	0.00 0.00 0.00	7.13 7.30 7.68	1 1 1
	70 Watt 100 Watt 175 Watt 250 Watt	7.20 6.29 6.45	0.00 0.00 0.00	6.29 6.45	7.13 7.30	0.00 0.00	7.13 7.30	1 1 1 1 1

		Rates E	ffective Decer	mber 2008	Pro	oposed Rat	es Effective C	October 1, 2009	
Note: Resi	idential rates based on seven cent Tier 3 - Tier 5								
	I and baseline allocations set at 55% of average								
	usage by CEC climate zone, assuming modification of								
	provided in Paragraph 4.b.iii and 4.b.v. CIA adjustment								Total Rate
	emented effective with rate changes made in 2010 for	Delivery	Generation	Total Rate		Delivery	Generation	Total Rate	Change
	3				_				
TC-1									
10-1	Energy Charge - \$/kWh	0.03245	0.07460	0.10705		0.04785	0.06704	0.11489	7.32%
	Energy Charge - \$/KVVII	0.03243	0.07460	0.10705		0.04765	0.06704	0.11409	1.32%
	Customer Charge - \$/day	0.413	0.000	0.413		0.477	0.000	0.477	15.50%
	Three-Phase Service - \$/day	0.138	0.000	0.138		0.030	0.000	0.030	-78.26%
WTR									
	Energy Charge - \$/Device/Month								
	50 0 - 50 kWh/month	4.35	3.73	8.08		14.20	3.35	17.55	117.17%
	100 51 - 100 kWh/month	5.98	7.46	13.44		16.61	6.71	23.32	73.47%
	150 101 - 150 kWh/month	7.62	11.19	18.81		19.00	10.06	29.06	54.48%
	200 151 - 200 kWh/month	9.23	14.92	24.15		21.40	13.41	34.81	44.13%
			18.65	29.51		23.78	16.76	40.54	37.37%
		10.86							
	300 251 - 300 kWh/month	12.46	22.38	34.84		26.17	20.12	46.29	32.84%
	350 301 - 350 kWh/month	14.08	26.11	40.19		28.55	23.46	52.01	29.42%
	400 351 - 400 kWh/month	15.72	29.84	45.56		30.97	26.82	57.79	26.83%
	450 401 - 450 kWh/month	17.34	33.57	50.91		33.35	30.17	63.52	24.77%
	500 451 - 500 kWh/month	18.97	37.31	56.28		35.77	33.53	69.30	23.14%
	Customer Charge - \$/Month	9.18	0.00	9.18		17.29	0.00	17.29	88.34%
	· · · · · · · · · · · · · · · · · · ·	3.10	0.00	3.10			0.00	20	55.5 F/0
	Three-Phase Service - \$/day	0.14	0.00	0.14		0.030	0.000	0.030	-78.57%
	Tillee-Filase Service - \$/day	0.14	0.00	0.14		0.030	0.000	0.030	-10.31 /6
		40.40		40.40		40.00	0.00	40.00	00 770/
	Inspection Charge - \$/Device/Month	10.18	0.00	10.18		12.60	0.00	12.60	23.77%
	Initialization of Service Charge -	6.79	0.00	6.79		6.79	0.00	6.79	0.00%
	One-time charge								
Wi-Fi-1									
	Energy Charge - \$/Device/Month	0.94	1.90	2.84		1.30	1.71	3.01	5.89%
	3, 4 4 3 4 4 4 4 4 4 4 4 4 4 4 4 4 4 4 4								
	Customer Charge - \$/Month	4.08	0.00	4.08		4.62	0.00	4.62	13.24%
	Oustomer Onlarge - wiwonin	4.00	0.00	4.00		4.02	0.00	4.02	10.2470
	Inventory/Maintenance Charge -	2.54	0.00	2.54		2.88	0.00	2.88	13.39%
		2.54	0.00	2.54		2.88	0.00	2.88	13.39%
	\$/Devoce/Month								
	Initialization of Service Charge -	8.55	0.00	8.55		9.68	0.00	9.68	13.22%
	One time charge/service account								
STANDBY	Y								
	Capacity Reservation Charge - \$/kW								
	500 kW or less					5.05	0.00	5.05	
	OUD NAA OI IE22					0.00	0.00	5.05	
	Below 2 kV					5.05	0.00	5.05	
	From 2 kV to 50 kV					4.80	0.00	4.80	
	above 50, but < 220 kV					1.24	0.00	1.24	
	220 kV and above					0.65	0.00	0.65	
Backı	up Generation Time-Related Demand Charge - \$/kW								
	500 kW or less					OAT	OAT	OAT	
	Below 2 kV								
	Summer On Peak					0.00	11.96	11.96	
	Summer Mid Peak					0.00	3.11	3.11	
	Cullinol Wild Feak					0.00	0.11	5.11	
	From 2 kV to 50 kV								
						0.00	40.00	40.00	
	Summer On Peak					0.00	12.80	12.80	
	Summer Mid Peak					0.00	3.24	3.24	
	above 50, but < 220 kV								
	Summer On Peak					0.00	11.49	11.49	
	Summer Mid Peak					0.00	2.12	2.12	
	220 kV and above								
	Summer On Peak					0.00	11.37	11.37	
	Summer Mid Peak					0.00	2.10	2.10	
	Odminor wild Feak					0.00	2.10	2.10	

Note: Residential rates based on seven cent Tier 3 - Tier 5 differential and baseline allocations set at 55% of average aggregate usage by CEC climate zone, assuming modification of AB1X as provided in Paragraph 4.b.ii and 4.b.v. ClA adjustment to be implemented effective with rate changes made in 2010 for PPP

Rates Effective December 2008 Delivery Generation Total Rate





Energy Charge - \$/kWh PEAK Plus Event Time Period (2pm-6pm) PEAK Plus Event Credit - On-Peak

California Alternate Rates for Energy Discount - %

Optional	CPP	rider	<	200	kW
----------	-----	-------	---	-----	----

CPP Event Energy Charge - \$/kWh		
DOMESTIC		
DOMESTIC CARE		
GS-1		
TOU-GS-1		
GS-2		
GS-2-TOU		
PA-1		

PA-2 AG-TOU TOU-PA-5

Summer Non-Event Energy Credit - \$/kWh DOMESTIC DOMESTIC CARE GS-1 TOU-GS-1

Summer Non-Event Demand Credit - \$/kWh GS-2 GS-2-TOU (On-Peak Dmand) PA-2

AG-TOU TOU-PA-5

Default CPP rider > 200 kW

TOU-8-SEC 2 p.m. to 6 p.m CPP Event Energy Charge - \$/kWh Summer On Peak Demand Credit - \$/kW

2 p.m. to 6 p.m CPP Event Energy Charge - \$/kWh Summer On Peak Demand Credit - \$/kW

TOU-8-SUB 2 p.m. to 6 p.m CPP Event Energy Charge - \$/kWh Summer On Peak Demand Credit - \$/kW

AG-TOU 2 p.m. to 6 p.m CPP Event Energy Charge - \$/kWh Summer On Peak Demand Credit - \$/kW

2 p.m. to 6 p.m CPP Event Energy Charge - \$/kWh Summer On Peak Demand Credit - \$/kW

0.00000	1.36229	1.36229
0.00000	1.36229	1.36229
0.00000	1.36229	1.36229
0.00000	1.36229	1.36229
0.00000	1.36229	1.36229
0.00000	1.36229	1.36229
0.00000	1.36229	1.36229
0.00000	1.36229	1.36229
0.00000	1.36229	1.36229
0.00000	1.36229	1.36229

0.00000	(0.04032)	(0.04032)
0.00000	(0.03798)	(0.03798)
0.00000	(0.04044)	(0.04044)
0.00000	(0.04044)	(0.04044)
0.00000	(0.02752)	(0.02752)

0.00	(10.19)	(10.19)
0.00	(9.39)	(9.39)
0.00	(7.44)	(7.44)
0.00	(8.69)	(8.69)
0.00	(12.39)	(12.39)

1.36229	1.36229
(11.62)	(11.62)

1.36229

1 28157

(12.47)

1.33322	1.33322
(12.20)	(12.20)

1.36229

1.28157

(12.47)

0.00000

0.00000

0.00000

0.00000 (13.02) (13.02) 0.00000 1.36229 1.36229 0.00000 (8.69) (8.69)