STATE OF CALIFORNIA

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

Edmund G. Brown Jr., *Governor*

December 5, 2012

Advice Letter 3517-E

Brian K. Cherry
Vice President, Regulation and Rates
Pacific Gas and Electric Company
77 Beale Street, Mail Code B10C
P.O. Box 770000
San Francisco, CA 94177

Subject: Notice of Federal Energy Regulatory Commission Rate Increase Filing (TO12)

Dear Mr. Cherry:

Advice Letter 3517-E is effective November 16, 2012.

Sincerely,

Edward Randolph

Edward F. Randolph, Director
Energy Division

Pacific Gas and Electric Company®

Brian K. Cherry
Vice President
Regulatory Relations

77 Beale Street, Room 1087
San Francisco, CA 94105

Mailing Address
Mail Code B10C
Pacific Gas and Electric Company
P.O. Box 770000
San Francisco, CA 94177

August 24, 2009

Advice 3517-E
(Pacific Gas and Electric Company ID U 39 E)

Public Utilities Commission of the State of California

<u>Subject:</u> **Notice of Federal Energy Regulatory Commission Rate Increase Filing (TO12)**

<u>Purpose</u>

Pacific Gas and Electric Company (PG&E) hereby submits this advice letter to provide the California Public Utilities Commission (Commission) with notice of PG&E's recent filing with the Federal Energy Regulatory Commission (FERC) requesting a transmission rate increase for its retail electric customers. The purpose of PG&E's FERC filing is to request rates for 2010 that reflect PG&E's most current estimates of the cost of providing transmission service.

<u>Background</u>

PG&E's twelfth FERC-jurisdictional electric transmission revenue requirement request (TO12) was filed with the FERC on July 30, 2009, and assigned FERC Docket No. ER09-1521-000.

The Commission has long recognized that FERC has jurisdiction over unbundled retail electric transmission rates in California, including transmission services provided under the FERC-approved California Independent System Operator Corporation (ISO) Tariff. To the extent that FERC decisions addressing ISO or other transmission service have been issued, they are deemed reasonable for purposes of inclusion in retail electric rates. See *New York v. FERC,* 535 US 1. (2002). In this decision, the Court held that "when a bundled retail sale is unbundled and becomes separate transmission and power sales transactions, the resulting transmission transaction falls within the Federal Sphere of regulation," *Id.* at 12 (citing FERC Order 888 approvingly, citations omitted).

Approved on May 26, 2005, Commission Resolution E-3930 established a process for CPUC notification and review of transmission-related changes, and embodies this understanding in new Process Element 1, where it states, "The Commission recognizes that under the filed rate doctrine, the Commission should allow a pass through of these transmission rates that are filed with and become effective at the FERC."

In its TO12 docket, PG&E has requested a $202.6 million increase over its currently effective retail transmission rates, which would represent, approximately, a 27 percent increase over currently-authorized transmission access rates. However, because transmission access rates account for a relatively small fraction of total bundled service rates (approximately 7 percent), the resulting system average bundled service rate increase would be only approximately 1.6 percent. PG&E has requested an effective date of October 1, 2009 for this rate change. Between now and that date, PG&E expects FERC to either accept the filed rates and authorize these rates to become effective on the requested date (subject to refund), or to accept the filing but suspend the effective date for a period of up to five months, with a possible effective date of March 1, 2010.

<u>Compliance with Resolution E-3930</u>

PG&E submits this advice letter pursuant to Process Element 3 of Resolution E-3930. Consistent with past practice, PG&E has also provided the Commission with a complete copy of the multiple-volume FERC filing and the Settlement on the same dates as filed with FERC, by service to Mr. Frank Lindh of the Commission's Legal Division.

Pursuant to Process Elements 3 through 5 of Resolution E-3930, PG&E provides in Attachment A, a complete copy of its Exhibit PGE-19, as filed in the TO12 docket. Exhibit PGE-19 includes a complete statement of PG&E's current and proposed retail transmission rates. In this advice letter, PG&E requests authority to revise each corresponding transmission rate component of its CPUC-jurisdictional tariffs on the date on which FERC ultimately authorizes these changes to become effective (subject to refund), and to make corresponding adjustments to PG&E's total applicable CPUC-jurisdictional rates, with exceptions only as described below for the residential tariffs.

As described under Process Elements 5 and 6 of Resolution E-3930, the constraints of California Assembly Bill 1X (AB 1X) continue to apply to total pre-California Solar Initiative (CSI) rates for residential usage up to 130 percent of baseline ("Tier 1 and 2 usage"). As shown in Attachment A, PG&E's TO12 filing would increase the transmission access component of total rates under each of PG&E's applicable residential tariffs, from $0.01006 to $0.01253 per kilowatt-hour (kWh).[1] Consistent with past practice, PG&E proposes to meet AB 1X

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1 The applicable residential tariff of $0.01006 per kWh represents the final approved rate in Order Approving Uncontested Settlement, Docket No. ER08-1318, Pacific Gas and Electric Co., 127 FERC ¶ 61,252 (2009). PG&E presented the rates ultimately approved in

requirements for the TO12 rate change by: (1) making the indicated adjustment to the transmission rate component of each residential tariff (increase of $0.00247 per kWh), applicable to all tiers; (2) decreasing the distribution and generation rates proportionately so that total pre-CSI residential rates for usage up to 130 percent of baseline do not change; (3) increasing the pre-CSI, non-California Alternate Rates for Energy (CARE), surcharges for usage in excess of 130 percent of baseline proportionately to ensure the non-CSI distribution and generation revenue allocated to the residential class is fully collected; and (4) adding CSI adders that vary by tier to determine the total rates.[2]

The result of these adjustments will be to hold PG&E's total pre-CSI bundled service rates fixed for residential Tier 1 and Tier 2 usage under 130 percent of baseline, as required by AB 1X. The method adopted in Decision (D.) 07-09-004 in PG&E's 2007 General Rate Case (GRC) Phase 2 proceeding (A.06-03-005) will be used to develop the necessary adjustments to the distribution and generation components of rates for usage in excess of 130 percent of baseline.

As anticipated under Process Element 4 of Resolution E-3930, PG&E will supplement this advice letter when the requested TO12 rate changes are approved, modified, denied or have been otherwise acted upon by FERC. When FERC authorizes rates to become effective, PG&E will also provide complete updated tariff sheets, including final adjustments to the generation rate components of the residential tariffs based on the specific method for adjusting upper-tier generation rates that is in effect on the date the FERC rate changes are to become effective.

<u>Protests</u>

Anyone wishing to protest this filing may do so by letter sent via U.S. mail, by facsimile or electronically, any of which must be received no later than September 14, 2009, which is 20 days after the date of this filing. Protests should be mailed to:

CPUC Energy Division
Tariff Files, Room 4005
DMS Branch
505 Van Ness Avenue
San Francisco, California 94102
Facsimile: (415) 703-2200
E-mail: jnj@cpuc.ca.gov and mas@cpuc.ca.gov

Copies of protests also should be mailed to the attention of the Director, Energy

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that decision to the CPUC in Advice 3497-E.

2 SB 1 authorized an exception to AB 1X or Water Code Section 80110 to allow total rates for residential usage less than 130 percent of baseline to increase by the amount of the CSI adder in Tiers 1 and 2.

Division, Room 4004, at the address shown above.

The protest also should be sent via U.S. mail (and by facsimile and electronically, if possible) to PG&E at the address shown below on the same date it is mailed or delivered to the Commission:

Brian K. Cherry
Vice President, Regulatory Relations
Pacific Gas and Electric Company
77 Beale Street, Mail Code B10C
P.O. Box 770000
San Francisco, California 94177

Facsimile: (415) 973-7226
E-mail: PGETariffs@pge.com

Effective Date

PG&E requests that this advice filing become effective on either October 1, 2009, or as soon as practicable after FERC authorizes these changes to become effective. PG&E proposes to consolidate the electric rate changes resulting from the transmission rate change, to the extent practicable, with the first planned rate change after FERC authorizes PG&E's request.

Notice

In accordance with General Order 96-B, Section IV, a copy of this advice letter is being sent electronically and via U.S. mail to parties shown on the attached list. Address changes to the General Order 96-B service list should be directed to San Heng at (415) 973-2640. Send all electronic approvals to PGETariffs@pge.com. Advice letter filings can also be accessed electronically at: **http://www.pge.com/tariffs**.

Brian Cherry ob

Vice President - Regulatory Relations

Service List: A.02-11-017

Attachment A: Exhibit 19 of PG&E's TO12 filing, FERC Docket No. ER09-1521-000

CALIFORNIA PUBLIC UTILITIES COMMISSION

ADVICE LETTER FILING SUMMARY
ENERGY UTILITY

MUST BE COMPLETED BY UTILITY (Attach additional pages as needed)

Company name/CPUC Utility No. **Pacific Gas and Electric Company (ID U39 M)**

Utility type:

☒ ELC ☒ GAS

☐ PLC ☐ HEAT ☐ WATER

Contact Person: Olivia M. Brown

Phone #: 415.973.9312

E-mail: oxb4@pge.com

EXPLANATION OF UTILITY TYPE

ELC = Electric GAS = Gas ☐
PLC = Pipeline HEAT = Heat WATER = Water

(Date Filed/ Received Stamp by CPUC)

Advice Letter (AL) #: 3517-E **Tier:** 2

Subject of AL: Notice of Federal Energy Regulatory Commission Rate Increase Filing (TO12)

Keywords (choose from CPUC listing): Compliance

AL filing type: ☐ Monthly ☐ Quarterly ☐ Annual ☒ One-Time ☐ Other ______________

If AL filed in compliance with a Commission order, indicate relevant Decision/Resolution #: Resolution E-3930

Does AL replace a withdrawn or rejected AL? No. If so, identify the prior AL: No

Summarize differences between the AL and the prior withdrawn or rejected AL: No.

Is AL requesting confidential treatment? If so, what information is the utility seeking confidential treatment for: No

Confidential information will be made available to those who have executed a nondisclosure agreement: N/A

Name(s) and contact information of the person(s) who will provide the nondisclosure agreement and access to the confidential information: N/A

Resolution Required? ☐ Yes ☒No

Requested effective date: October 1, 2009 No. of tariff sheets: N/A

Estimated system annual revenue effect (%): N/A

Estimated system average rate effect (%): N/A

When rates are affected by AL, include attachment in AL showing average rate effects on customer classes (residential, small commercial, large C/I, agricultural, lighting). N/A

Tariff schedules affected: N/A

Service affected and changes proposed: N/A

Protests, dispositions, and all other correspondence regarding this AL are due no later than 20 days after the date of this filing, unless otherwise authorized by the Commission, and shall be sent to:

CPUC, Energy Division
Tariff Files, Room 4005
DMS Branch
505 Van Ness Ave., San Francisco, CA 94102
jnj@cpuc.ca.gov and mas@cpuc.ca.gov

Pacific Gas and Electric Company
Attn: Brian K. Cherry, Vice President, Regulatory Relations
77 Beale Street, Mail Code B10C
P.O. Box 770000
San Francisco, CA 94177
E-mail: PGETariffs@pge.com

Attachment A: Exhibit 19 of PG&E's TO12 filing, FERC Docket No. ER09-1521-000

FILING WITH THE FEDERAL ENERGY REGULATORY COMMISSION

PACIFIC GAS AND ELECTRIC COMPANY

TRANSMISSION OWNER TARIFF
2010

EXHIBIT PGE-19

TRANSMISSION OWNER TARIFF

FERC DOCKET NO. ___________________

PACIFIC GAS AND ELECTRIC COMPANY

TRANSMISSION OWNER TARIFF

TO12

CLEAN VERSION

the ISO as the Participating TO's agent, as provided in Section 5.6 of this TO Tariff.

2. Termination. This TO Tariff may be terminated by the Participating TO upon such advance notice and with such authorization as FERC may require.

3. TO Definitions. Capitalized terms used in this TO Tariff shall have the meanings set out below unless otherwise stated or the context otherwise requires. Capitalized terms used in this Tariff and not defined below shall have the meanings set out in the ISO Tariff.

3.1 **Access Charge.** A charge paid by all UDCs, MSSs and, in certain cases, Scheduling Coordinators delivering Energy to Gross Load, as set forth in Section 26.1 of the ISO Tariff. The Access Charge includes the High Voltage Access Charge, the Transition Charge and the Low Voltage Access Charge, as applicable.

3.2 **AGC.** Generation equipment that automatically responds to signals from the ISO's EMS control in real time to control the power output of electric generators within a prescribed area in response to a change in system frequency, tieline loading, or the relation of these to each other, so as to maintain the target system frequency and/or the established interchange with other areas within the predetermined limits.

3.3 **Ancillary Services.** Regulation, Spinning Reserve, Non-Spinning Reserve, Voltage Support and Black Start together with such other interconnected operation services as the ISO may develop in cooperation with Market Participants to support the transmission of Energy from Generation resources to Loads while maintaining reliable operation of the ISO Controlled Grid in accordance with Good Utility Practice.

3.4 **Applicable Reliability Criteria.** The reliability standards established by NERC, to serve all Generation and Demand. "Congested" shall be construed accordingly.

3.12 Congestion Management. The alleviation of Congestion in accordance with applicable ISO Protocols and Good Utility Practice.

3.13 Converted Rights. Those transmission service rights defined in Section 4.3.1.6 of the ISO Tariff.

3.14 CPUC. The California Public Utilities Commission, or its successor.

3.15 [Omitted].

3.16 Demand. The rate at which Energy is delivered to Loads and Scheduling Points by Generation, transmission or distribution facilities. It is the product of voltage and the in-phase component of alternating current measured in units of watts or standard multiples thereof, e.g., 1,000 W = 1 kW, 1,000 kW = 1 MW, etc.

3.17 Direct Assignment Facilities. Facilities or portions of facilities that are owned by the Participating TO necessary to physically and electrically interconnect a particular party requesting Interconnection under this TO Tariff to the ISO Controlled Grid at the point of interconnection. Direct Assignment Facilities shall be specified in the Interconnection Agreement that governs Interconnection service to such party and shall be subject to FERC approval.

3.18 Dispatch. The operating control of an integrated electric system to: i) assign specific Generation Units and other sources of supply to effect the supply to meet the relevant area Demand taken as Load rises or falls; ii) control operations and

3.23 Energy. The electrical energy produced, flowing, or supplied by generation, transmission, or distribution facilities, being the integral with respect to time of the instantaneous power, measured in units of watt-hours or standard multiples thereof, e.g., 1,000 Wh = 1 kWh, 1,000 kWh = 1 MW, etc.

3.24 Entitlement. The right of a Participating TO obtained through contract or other means to use another entity's transmission facilities for the transmission of Energy.

3.25 Existing Contracts. The contracts which grant transmission service rights in existence on the ISO Operations Date (including any contracts entered into pursuant to such contracts) as may be amended in accordance with their terms or by agreement between the parties thereto from time to time.

3.26 Existing Rights. Those transmission service rights defined in Section 16.1 of the ISO Tariff.

3.27 Expedited Interconnection Agreement. A contract between a party which has submitted a Request for Expedited Interconnection Procedures and the Participating TO under which the Participating TO agrees to process, on an expedited basis, the Completed Interconnection Application of such party and which sets forth the terms, conditions, and cost responsibilities for such interconnection.

3.28 Facilities Study Agreement. An agreement between a Participating TO and either a party requesting Interconnection to the ISO Controlled Grid, Market Participant, Project Sponsor, or identified principal beneficiaries pursuant to which the party requesting such Interconnection, Market Participants, Project Sponsor, or identified principal beneficiaries agrees to reimburse the Participating TO for the cost of performing or reviewing a Facilities Study.

3.29 Facility or Facilities Study. An engineering study conducted to determine required modifications to the Participating TO's transmission system, including the estimated cost and scheduled completion date for such modifications that will be required to provide needed services.

3.30 FERC. The Federal Energy Regulatory Commission, or its successor.

3.31 FPA. The Federal Power Act, 16 U.S.C. § 791a et seq., as it may be amended from time to time.

3.32 [Omitted].

3.33 [Omitted].

3.34 Generating Unit. An individual electric generator and its associated plant and apparatus whose electrical output is capable of being separately identified and metered or a Physical Scheduling Plant that, in either case, is: (a) located within the ISO Control Area; (b) connected to the ISO Controlled Grid, either directly or via interconnected transmission, or distribution facilities; and (c) that is capable of producing and delivering net Energy (Energy in excess of a generating station's internal power requirements).

Standby Service from the Participating TO or can be curtailed concurrently with an outage of the Generating Unit serving the Load.

3.38 High Voltage Access Charge. A component of the Access Charge determined by the ISO under Section 26.1 of the ISO Tariff.

3.39 High Voltage Transmission Facility. A transmission facility under the operational control of the ISO that is owned by the Participating TO or to which the Participating TO has an Entitlement that may be associated with a Converted Right, which operates at a voltage at or above 200 kilovolts, and supporting facilities, and the costs of which are not directly assigned to one or more specific customers.

3.40 High Voltage Transmission Revenue Requirement. The portion of the Participating TO's TRR associated with and allocable to the Participating TO's High Voltage Transmission Facilities and Converted Rights associated with High Voltage Transmission Facilities.

3.41 High Voltage Utility-Specific Rate. The Participating TO's High Voltage Transmission Revenue Requirement divided by the Participating TO's forecast of its Gross Load.

3.42 High Voltage Wheeling Access Charge. The Wheeling Access Charge assessed by the ISO associated with the recovery of the Participating TO's High Voltage Transmission Revenue Requirement in accordance with Section 26.1 of the ISO Tariff.

3.43 [Omitted].

[Reserved for Future Use]

3.44 Interconnection. Transmission facilities, other than additions or replacements to existing facilities that: i) connect one system to another system where the facilities emerge from one and only one substation of the two systems and are functionally separate from the ISO Controlled Grid facilities such that the facilities are, or can be, operated and planned as a single facility; or ii) are identified as radial transmission lines pursuant to contract; or iii) produce Generation at a single point on the ISO Controlled Grid; provided that such interconnection does not include facilities that, if not owned by the Participating TO, would result in a reduction in the ISO's Operational Control of the Participating TO's portion of the ISO Controlled Grid.

3.45 Interconnection Agreement. A contract between a party requesting Interconnection and the Participating TO that owns the transmission facility with which the requesting party wishes to interconnect.

3.46 Interconnection Application. An application that requests Interconnection to the ISO Controlled Grid.

3.47 Interest. Interest shall be calculated in accordance with the methodology costs of which are not directly assigned to one or more specific customers.

3.61 Low Voltage Transmission Revenue Requirement. The portion of the Participating TO's TRR associated with and allocable to the Participating TO's Low Voltage Transmission Facilities and Converted Rights associated with Low Voltage Transmission Facilities.

3.62 Low Voltage Wheeling Access Charge. The Wheeling Access Charge associated with the recovery of the Participating TO's Low Voltage Transmission Revenue Requirement in accordance with Section 26.1 of the ISO Tariff.

3.63 Market Participant. An entity, including a Scheduling Coordinator, who participates in the Energy marketplace through the buying, selling, transmission, or distribution of Energy or Ancillary Services into, out of, or through the ISO Controlled Grid.

3.64 MSS (Metered Subsystem). A geographically contiguous system, located within a single zone which has been operating as an electric utility for a number of years prior to the ISO Operations Date as a municipal utility, water district, irrigation district, state agency or federal power marketing authority subsumed within the ISO Balancing Authority Area and encompassed by ISO certified revenue quality meters at each interface point with the ISO Controlled Grid and ISO-certified revenue quality meters on all Generating Units or, if aggregated, each individual resource and Participating Load internal to the system, which is operated in accordance with a MSS agreement described in Section 4.9.1 of the ISO Tariff.

3.65 NERC. The North American Electric Reliability Council or its successor.

3.66 [Omitted].

3.67 [Omitted].

3.68 New High Voltage Transmission Facility. A High Voltage Transmission Facility of the Participating TO that enters service on or after the Transition Date described in Section 4 of Appendix F, Schedule 3 of the ISO Tariff, or a capital addition made on or after the Transition Date described in Section 4.1 of Appendix F, Schedule 3 of the ISO Tariff to a High Voltage Transmission Facility that existed prior to the Transition Date.

3.69 New Participating TO. A Participating TO that is not an Original Participating TO.

3.70 Non-Participating TO. A TO that is not a party to the TCA or for the purposes of Sections 16.1 of the ISO Tariff the holder of transmission service rights under an Existing Contract that is not a Participating TO.

3.71 Non-Spinning Reserve. The portion of off-line generating capacity that is capable of being synchronized and ramping to a specified load in ten minutes (or load that is capable of being interrupted in ten minutes) and that is capable of running (or being interrupted) for at least two hours.

3.72 Operational Control. The rights of the ISO under the Transmission Control Agreement and the ISO Tariff to direct Participating TOs how to operate their transmission lines and facilities and other electric plant affecting the reliability of those lines and facilities for the purpose of affording comparable non-discriminatory transmission access and meeting Applicable Reliability Criteria.

3.73 Original Participating TO. A Participating TO that was a Participating TO as of January 1, 2000. The Original Participating TOs are Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas and Electric Company.

accordance with Section 24 of the ISO Tariff.

3.80 Regional Transmission Group ("RTG"). A voluntary organization approved by FERC and composed of transmission owners, transmission users, and other entities, organized to efficiently coordinate the planning, expansion and use of transmission on a regional and inter-regional basis.

3.81 Regulation. The service provided either by Generating Units certified by the ISO as equipped and capable of responding to the ISO's direct digital control (AGC) signals, or by System Resources that have been certified by the ISO as capable of delivering such service to the ISO Balancing Authority Area, in an upward and downward direction to match, on a Real Time basis, Demand and resources, consistent with established NERC and WSCC reliability standards, including any requirements of the NRC. Regulation is used to control the Power output of electric generators within a prescribed area in response to a change in system frequency, tieline loading, or the relation of these to each other so as to maintain the target system frequency and/or the established Interchange with other Balancing Authority Areas within the predetermined Regulation Limits. Regulation includes both the increase of output by a Generating Unit or System Resource (Regulation Up) and the decrease in output by a Generating Unit or System Resource (Regulation Down). Regulation Up and Regulation Down are distinct capacity products, with separately stated requirements and ASMPs in each Settlement Period.

3.82 Reliability Criteria. Pre-established criteria that are to be followed in order to maintain desired performance of the ISO Controlled Grid under contingency or steady state conditions.

3.83 Reliability Services Balancing Account ("RSBA"). A mechanism to ensure that all transmission related Reliability Services Costs, as that term is defined in the Master Definitions Supplement, Appendix A to the currently effective ISO Tariff, which are deemed by the ISO as necessary to maintain reliable electric service in the ISO Control Area and whose costs are billed to the Participating TO by the ISO pursuant to the ISO Tariff, are allocated to and received from End-Use Customers, TO Tariff Wholesale Customers, and Existing Contract customers to which PG&E's Reliability Services Tariff (or reliability services-related contract amendments apply), withdrawing Energy from the ISO Controlled Grid on the Participating TO's transmission system.

3.84 Reliability Services Charge. A charge paid by End Use Customers, TO Tariff Wholesale Customers, and Existing Contract customers who take service under the Reliability Services Tariff or a Reliability Services Rate Schedule, whichever is applicable, withdrawing Energy from the ISO Controlled Grid on the Participating TO's transmission system, as set forth in Section 15 of this TO Tariff. The Reliability

Services Charge will recover the Participating TO's reliability services costs, as annually calculated from the balance in the RSBA and a forecast of Reliability Services costs for the following year, from End Use Customers, TO Tariff Wholesale Customers, and Existing Contract customers to which PG&E's Reliability Services Tariff (or reliability services-related contract amendments) applies. In order to mitigate the initial rate increase Wholesale Customers will experience from these Reliability Services Charges, the otherwise applicable Reliability Services Charge will be multiplied by a factor of one-third (1/3) until December 31, 2001, and a factor of two-thirds (2/3) from January 1, 2002 until December 31, 2002. Any Reliability Services costs that are not collected from either TO Tariff Wholesale Customers or Existing Contract customers to which PG&E's Reliability Services Tariff (or reliability services-related contract amendments) applies, prior to December 31, 2002, due to the mitigation described above will be allocated to and collected from End Use Customers. Additionally, if FERC, should disallow recovery of any Reliability Services costs from Wholesale Customers those costs shall be included in the allocation to End Use Customers.

3.85 **Reliability Upgrade.** The transmission facilities, other than Direct Assignment Facilities, beyond the first point of Interconnection necessary to interconnect a wholesale load safely and reliably to the ISO Controlled Grid, which would not have been necessary but for the Interconnection of a wholesale load, including network upgrades necessary to remedy short circuit or stability problems resulting from the interconnection of a wholesale load to the ISO Controlled Grid. Reliability Upgrades also include, consistent with WSCC practice, the facilities necessary to mitigate any adverse impact a wholesale load's interconnection may have on a path's WSCC path rating. Reliability Upgrades shall be specified in the Interconnection Agreement that governs Interconnection service to the wholesale load and shall be subject to FERC approval.

3.86 **[Omitted].**

3.87 Request for Expedited Interconnection Procedures. A written request by which an applicant for Interconnection can request expedited processing of its Interconnection Application.

3.88 Scheduling Coordinator. An entity certified by the ISO for the purposes of undertaking the functions specified in Section 4.5.3 of the ISO Tariff.

3.89 Scheduling Point. A location at which the ISO Controlled Grid or a transmission facility owned by a Transmission Ownership Right holder is connected, by a group of transmission paths for which a physical, non-simultaneous transmission capacity rating has been established for Congestion Management, to transmission facilities that are outside the ISO's Operational Control.

3.90 Standby Service. Service provided by the Participating TO which allows a Standby Service Customer, among other things, access to High Voltage Transmission Facilities for the delivery of backup power on an instantaneous basis to ensure that Energy may be reliably delivered to the Standby Service Customer in the event of an outage of a Generating Unit serving the customer's Load.

3.91 Standby Service Customer. A retail End-Use Customer of the Participating TO that receives Standby Service and pays a Standby Rate.

3.92 Standby Transmission Demand Rate. The Demand portion of a rate assessed a Standby Service Customer by the Participating TO, as approved by the Local Regulatory Authority or FERC, as applicable, for Standby Service which compensates the Participating TO for, among other things, costs of High Voltage Transmission Facilities.

3.93 Standby Transmission Demand Revenue. The transmission revenue associated with the demand portion of Standby Service rates collected by the firm contractual rights to use transmission facilities.

3.103 <u>Transmission Revenue Balancing Account Adjustment ("TRBAA")</u>. A mechanism established by the Participating TO which will ensure that all Transmission Revenue Credits flow through to or are received from End-Use Customers. The TRBAA will also ensure that Transmission Revenue Credits and other credits specified in Section 6, 8, and 13 of Appendix F, Schedule 3 of the ISO Tariff, flow through to other Participating TOs and Wheeling customers for purposes of calculating the High Voltage Access Charge, Low Voltage Access Charge, High Voltage Wheeling Access Charge, Low Voltage Wheeling Access Charge and High Voltage Utility-Specific Access Charge. The 2012 TRBAA will also include an adjustment, if any, for the difference between 1) $10,427,584 and 2) actual revenues received by the Participating TO that are associated with calendar year 2010 and related to transmission for others in accordance with Existing Contracts.

3.104 <u>Transmission Revenue Credit</u>. The proceeds received from the ISO and charges imposed by the ISO that are received and paid by the Participating TO in its role as a Participating TO, as defined by "Transmission Revenue Credit" in the Master Definitions Supplement, Appendix A to the currently effective ISO Tariff.

3.105 <u>Transmission Revenue Requirement ("TRR")</u>. The total annual authorized revenue requirement associated with transmission facilities and Entitlements turned over to the Operational Control of the ISO by the Participating TO. The costs of any transmission facility turned over to the Operational Control of the ISO shall be fully included in the Participating TO's TRR. The TRR is shown in Appendix I.

3.106 <u>Uncontrollable Force</u>. Any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm, flood, earthquake, explosion, any curtailment, order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities or any other cause beyond the reasonable control of the ISO or Market Participant or the PX or PX Participant (as the case may be) which could not be
civilian authorities or any other cause beyond the reasonable control of the ISO or Market Participant or the PX or PX Participant (as the case may be) which could not be

avoided through the exercise of Good Utility Practice.

3.107 <u>Usage Charge</u>. The amount of money, per 1kW of scheduled flow, that the ISO charges a Scheduling Coordinator for use of a specific congested Inter-Zonal Interface during a given hour.

3.108 <u>Utility Distribution Company ("UDC")</u>. An entity that owns a Distribution System for the delivery of Energy to and from the ISO Controlled Grid, and/or that provides regulated retail electric service to End-Users.

3.109 <u>Voltage Support</u>. Services provided by Generating Units or other equipment such as shunt capacitors, static var compensators, or synchronous condensers that are required to maintain established grid voltage criteria. This service is required under normal or system emergency conditions.

3.110 <u>Western System Coordinating Council ("WSCC")</u>. The Western System Coordinating Council or its successor.

3.111 <u>Wheeling Access Charge</u>. The charge assessed by the ISO that is paid by a Scheduling Coordinator for Wheeling in accordance with Section 26.1.4.1 of the ISO Tariff. Wheeling Access Charges shall not apply for Wheeling under a bundled non-economy Energy coordination agreement of a Participating TO executed prior to July 9, 1996. The Wheeling Access Charge consists of a High Voltage Wheeling Access Charge and, if applicable, a Low Voltage Wheeling Access Charge.

3.112 <u>Wheeling Out</u>. Except for Existing Rights exercised under an Existing Contract in accordance with Sections 16.1 of the ISO Tariff, the use of the ISO Controlled Grid for the transmission of Energy from a Generating Unit located within the ISO Controlled Grid to serve a Load located outside the transmission and Distribution System of a Participating TO.

3.113 <u>Wheeling Through</u>. Except for Existing Rights exercised under an Existing Contract in accordance with Sections 16.1 of the ISO Tariff, the use of the ISO Controlled Grid for the transmission of Energy from a resource located outside the ISO Controlled Grid to serve a Load located outside the transmission and Distribution System of a Participating TO.

3.114 <u>Wheeling</u>. Wheeling Out or Wheeling Through.

3.115 <u>Wholesale Customer</u>. A person wishing to purchase Energy and Ancillary Services at a Bulk Supply Point or a Scheduling Point for resale.

3.116 [Omitted].

4. Eligibility. Transmission service over a Participating TO's system shall be provided only to Eligible Customers. Any dispute as to whether an End-Use Customer is eligible for wholesale transmission service shall be resolved by FERC and any dispute as to whether an End-Use Customer is eligible for service under this TO Tariff shall be resolved by the Local Regulatory Authority.

5. Access Charges and Transmission Rates.

5.1 Low Voltage Access Charge. The Low Voltage Access Charge shall be determined in accordance with the ISO Tariff. The Low Voltage Access Charge customer shall pay the Participating TO a Low Voltage Access Charge equal to the product of the Participating TO's Low Voltage Access Charge rate and the kilowatt-hours of transmission service provided under the ISO Tariff to the Low Voltage Access Charge customers. The Participating TO shall not assess the Low Voltage Access Charge to any other Participating TO for transmission service over Low Voltage Transmission Facilities that such other Participating TO receives and pays for under an Existing Contract. Where a customer receives deliveries of energy at voltage levels both above and below 200 kV, the Low Voltage Access Charge shall be applied only to

5.5 Transmission Revenue Balancing Account Adjustment ("TRBAA"). The Participating TO shall maintain a Transmission Revenue Balancing Account ("TRBA") that will ensure that all Transmission Revenue Credits associated with transmission service from the ISO are flowed through to or recovered from, as appropriate, customers taking service. The TRBAA shall be equal to:

$$TRBAA = Cr + Cf + I + FFU$$

Where:

Cr = The principal balance in the TRBA recorded in FERC Account No. 254 as of September 30 of the year prior to commencement of the January billing cycle. This balance represents the unamortized balance in the TRBA from the previous period and the difference in the amount of revenues or expenditures from Transmission Revenue Credits and the amount of such revenues or expenditures that has been refunded to or collected from customers through operation of the TRBAA, plus an allocation for a three year amortization of ETC Cost Differentials and for purposes of calculating the 2012 TRBAA, the difference between 1) $10,427,584 and 2) actual revenues received by the Participating TO which are associated with calendar year 2010 and are related to transmission for others in accordance with Existing Contracts, will be added to the TRBA on December 31, 2010;

Cf = The forecast of Transmission Revenue Credits for the following calendar year;

I = The interest balance for the TRBA, which shall be calculated using the interest rate pursuant to Section 35.19(a) of FERC's regulations under the Federal Power Act (18 CFR Section 35.19(a)). Interest shall be calculated based on the average TRBA principal balance each month, compounded quarterly; and

FFU = Franchise Fees and Uncollectible Accounts.

APPENDIX I
Transmission and Reliability Services Revenue Requirements [1]

1. **The Transmission Revenue Requirement for purposes of calculating End-User transmission rates shall be $925,582,401, which is composed of the Base Transmission Revenue Requirement of $946,425,145, and the TRBAA of ($20,842,744).[2]**

2. **For purposes of the ISO's calculation of Access Charges under Section 26.1 of the ISO Tariff:**

   a. **The High Voltage Transmission Revenue Requirement shall be $366,491,032, which is composed of a High Voltage Base Transmission Revenue Requirement of $434,012,133, Standby Transmission Demand Revenue credit of ($1,648,424), and a High Voltage TRBAA of ($65,872,678).**

   b. **The Low Voltage Transmission Revenue Requirement shall be $465,444,793, which is composed of a Low Voltage Base Transmission Revenue Requirement of $497,648,749, Standby Transmission Demand Revenue credit of ($1,962,595), and a Low Voltage TRBAA of ($30,241,361).**

   c. **The High Voltage Transmission Revenue Requirement associated with New High Voltage Transmission Facilities is $206,875,128, which is composed of a High Voltage Base Transmission Revenue Requirement of $245,897,227, Standby Transmission Demand Revenue credit of ($933,572), and a High Voltage TRBAA of ($38,088,527).**

   d. **The forecast of Gross Load at the High Voltage/Low Voltage interface is 90,326,715 megawatt-hours.**

[1] Total revenue requirement associated with transmission facilities and entitlements turned over to the operational control of the ISO by the Participating TO, which reflects a reduction or increase for Transmission Revenue Credits.

[2] The TRBAA amount includes ($71,411,984) calculated pursuant to Section 5.5 plus $50,569,240 calculated pursuant to Section 5.5.1.

APPENDIX II

Access Charges for Wholesale Transmission

	Per kWh
High Voltage Access Charge ……………………………….	**See ISO Tariff**
Low Voltage Access Charge………………………………..	**$0.005153**
High Voltage Utility-Specific Access Charge…………….	**$0.004057**

High Voltage Wheeling Access Charge

High Voltage Wheeling Access Charge…………………...See ISO Tariff

Low Voltage Wheeling Access Charge

High Voltage Wheeling Access Charge…………………...See ISO Tariff

Low Voltage Wheeling Access Charge.………………….. $0.005153

APPENDIX III

Access Charges for End-Use Service [1, 2]

TABLE OF CONTENTS

[1] These charges represent the rates for recovery of the Base Transmission Revenue Requirement.
A TRBAA Rate of ($0.00021) per kWh (Docket No. ER09-34-000) and a TACBAA Rate of ($0.00006) per kWh (Docket No. ER09-376-000) shall also apply to all of the rate schedules described in this Appendix.

[2] The applicability of these rates is described in the California Public Utilities Commission jurisdictional retail tariffs.

RESIDENTIAL SCHEDULES		TO RATES	ECRA RATES
SCHEDULE E-1 **SCHEDULE E-3** **SCHEDULE EL-1 (CARE)** **SCHEDULES E-6 AND EL-6 (CARE)** **SCHEDULES E-7 AND EL-7 (CARE)** **SCHEDULES E-A7 AND EL-A7 (CARE)** **SCHEDULE E-8** **SCHEDULE EL-8 (CARE)** **SCHEDULE E-9**	**SCHEDULE EE** **SCHEDULE EM AND EML (CARE)** **SCHEDULE ES AND ESL (CARE)** **SCHEDULE ESR AND ESRL (CARE)** **SCHEDULE ET AND ETL (CARE)**		
Energy Charges ($/kWh)		$0.01253	($0.00117)

COMMERCIAL & INDUSTRIAL SCHEDULES	TO RATES	ECRA RATES
SCHEDULE A-1 **SCHEDULE A-6** **SCHEDULE A-15** **SCHEDULE TC-1**		
Energy Charges ($/kWh)	$0.01171	($0.00110)
SCHEDULE A-10		
BASIS FOR DEMAND CHARGE: The customer will be billed for demand according to the customer's "maximum demand" each month. The number of kW used will be recorded over 15-minute intervals; the highest 15-minute average in the month will be the customer's maximum demand. SPECIAL CASES: (1) If the customer's use of energy is intermittent or subject to severe fluctuations, a 5-minute interval may be used, and (2) If the customer uses welders, the demand charge will be subject to the minimum demand charges for those welders' ratings, as explained in Section J of PG&E's CPUC Rule 2.		
Maximum Demand Charge ($/kW/mo)	$4.01	
Energy Charges ($/kWh)		($0.00098)
SCHEDULE E-19		
BASIS FOR DEMAND CHARGE: Demand will be averaged over 15-minute intervals for customers whose maximum demand exceeds 499 kW. "Maximum demand" will be the highest of all the 15-minute averages for the billing month. If the customer's use of electricity is intermittent or subject to severe fluctuations, a 5-minute interval may be used. If the customer has any welding machines, the diversified resistance welder load, calculated in accordance with Section J of PG&E's CPUC Rule 2, will be considered the maximum demand if it exceeds the maximum demand that results from averaging the demand over 15-minute intervals. The customer's maximum-peak-period demand will be the highest of all the 15-minute averages for the peak period during the billing month. • This schedule has three demand charges, a maximum-peak-period-demand charge, a maximum-part-peak-period and a maximum demand charge. The maximum-peak-period demand charge per kilowatt applies to the maximum demand during the month's peak hours, the maximum part-peak-period demand charge applies to the maximum demand during the month's part-peak hours, and the maximum demand charge per kilowatt applies to the maximum demand at any time during the month. The bill will include all of these demand charges. • The monthly charges may be increased or decreased based upon the power factor. POWER FACTOR ADJUSTMENTS: Bills will be adjusted based on the power factor for all customers except those selecting voluntary E-19 service. The power factor is computed from the ratio of lagging reactive kilovolt-ampere-hours to the kilowatt-hours consumed in the month. Power factors are rounded to the nearest whole percent. The rates in this rate schedule are based on a power factor of 85 percent. If the average power factor is greater than 85 percent, the total monthly bill will be reduced by the product of the power factor rate and the kilowatt-hour usage for each percent. For customers taking Non-Firm Service, power factor adjustments will be applied to the customer's total bill, net of charges and credits billed under Schedule E-NF.		
SCHEDULE E-19 Demand Charges ($/kW/mo)	$4.01	
Energy Charges ($/kWh)		($0.00098)

	TO RATES	ECRA RATES
SCHEDULE E-20		

BASIS FOR DEMAND CHARGE: Demand will be averaged over 15-minute intervals. "Maximum demand" will be the highest of all the 15-minute averages for the billing month. If the customer's use of electricity is intermittent or subject to severe fluctuations, a 5-minute interval may be used. If the customer has any welding machines, the diversified resistance welder load, calculated in accordance with Section J of PG&E's CPUC Rule 2, will be considered the maximum demand if it exceeds the maximum demand that results from averaging the demand over 15-minute intervals. The customer's maximum-peak-period demand will be the highest of all the 15-minute averages for the peak period during the billing month.

- Schedule E-20 has three demand charges, a maximum-peak-period demand charge, a maximum-part-peak-period demand charge, and a maximum-demand charge. The maximum-peak-period demand charge per kilowatt applies to the maximum demand during the month's peak hours, the maximum-part-peak demand charge applies to the maximum demand during the month's part-peak hours, and the maximum demand charge per kilowatt applies to the maximum demand at any time during the month. The bill will include all of these demand charges.
- The monthly charges may be increased or decreased based upon the power factor, using the same method as described above for Schedule E-19.

	TO RATES	ECRA RATES
SCHEDULE E-20 Demand Charges ($/kW/mo)	$4.06	
Energy Charges ($/kWh)		($0.00081)
SCHEDULE E-37		
Energy Charges ($/kWh)	$0.00932	($0.00081)
SCHEDULE S		

RESERVATION CAPACITY: The Reservation Capacity to be used for billing under the above rates shall be as set forth in the customer's contract for service. For new or revised contracts, the Reservation Capacity shall be determined by the customer. However, if the customer's standby demand exceeds this new contracted capacity in any billing month, that standby demand shall become the new Reservation or Contract Capacity for 12 months, beginning with that month. See Special Condition 7 for the definition of Reservation Capacity for Supplemental Standby Service customers.

The **Reservation Charge**, in dollars per kilowatt (kW), applies to 85 percent of the customer's Reservation Capacity, as defined in Special Condition 1 of the tariffs.

POWER FACTOR ADJUSTMENT: When the customer’s Reservation Capacity is greater than 500 kW, the bill will be adjusted based on the power factor. The power factor is derived from the ratio of kWh to kVAh consumed in the month. Power factors are averaged and rounded to the nearest whole percent.

The rates in this rate schedule are based on a power factor of 85 percent. If the average power factor is greater than 85 percent, the total monthly bill will be reduced by the product of the power factor adjustment rate and the kilowatt-hour usage for each percentage point above 85 percent. If the average power factor is less than 85 percent, the total monthly bill will be increased by the product of the power factor adjustment rate and the kilowatt-hour usage for each percentage point below 85 percent.

The customer shall pay only the greater of the power factor adjustment and the reactive demand charge.

Generators for which ISO standards apply must also meet power factor requirements specified in the ISO tariff.

	TO RATES	ECRA RATES
Energy Charges ($/kWh)	$0.00859	($0.00309)
Reservation Charge ($/kW/mo)	$0.48	

	TO RATES	ECRA RATES
AGRICULTURAL SCHEDULES		
The CPUC-jurisdictional retail tariffs should be referred to for detailed descriptions of how agricultural demand charges are assessed.		
SCHEDULE AG-1 **SCHEDULE AG-R** **SCHEDULE AG-V** **SCHEDULE AG-4** **SCHEDULE AG-5** **SCHEDULE AG-ICE**		
Energy Charges ($/kWh)	$0.00932	($0.00081)
STREETLIGHTING SCHEDULES		
SCHEDULE LS-1 **SCHEDULE LS-2** **SCHEDULE LS-3** **SCHEDULE OL-1**		
Energy Charges ($/kWh)	$0.00504	($0.00069)

PACIFIC GAS AND ELECTRIC COMPANY

TRANSMISSION OWNER TARIFF

TO12

REDLINED VERSION

the ISO as the Participating TO's agent, as provided in Section 5.6 of this TO Tariff.

2. Termination. This TO Tariff may be terminated by the Participating TO upon such advance notice and with such authorization as FERC may require.

3. TO Definitions. Capitalized terms used in this TO Tariff shall have the meanings set out below unless otherwise stated or the context otherwise requires. Capitalized terms used in this Tariff and not defined below shall have the meanings set out in the ISO Tariff.

3.1 Access Charge. A charge paid by all UDCs, MSSs and, in certain cases, Scheduling Coordinators delivering Energy to Gross Load, as set forth in Section 26.1 of the ISO Tariff. The Access Charge includes the High Voltage Access Charge, the Transition Charge and the Low Voltage Access Charge, as applicable.

3.2 AGC. Generation equipment that automatically responds to signals from the ISO's EMS control in real time to control the power output of electric generators within a prescribed area in response to a change in system frequency, tieline loading, or the relation of these to each other, so as to maintain the target system frequency and/or the established interchange with other areas within the predetermined limits.

3.3 Ancillary Services. Regulation, Spinning Reserve, Non-Spinning Reserve, ~~Replacement Reserve,~~ Voltage Support and Black Start together with such other interconnected operation services as the ISO may develop in cooperation with Market Participants to support the transmission of Energy from Generation resources to Loads while maintaining reliable operation of the ISO Controlled Grid in accordance with Good Utility Practice.

3.4 Applicable Reliability Criteria. The reliability standards established by NERC, to serve all Generation and Demand. "Congested" shall be construed accordingly.

3.12 Congestion Management. The alleviation of Congestion in accordance with applicable ISO Protocols and Good Utility Practice.

3.13 Converted Rights. Those transmission service rights defined in Section 4.3.1.6~~16.2.1A.1~~ of the ISO Tariff.

3.14 CPUC. The California Public Utilities Commission, or its successor.

3.15 [Omitted].

3.16 Demand. The rate at which Energy is delivered to Loads and Scheduling Points by Generation, transmission or distribution facilities. It is the product of voltage and the in-phase component of alternating current measured in units of watts or standard multiples thereof, e.g., 1,000 W = 1 kW, 1,000 kW = 1 MW, etc.

3.17 Direct Assignment Facilities. Facilities or portions of facilities that are owned by the Participating TO necessary to physically and electrically interconnect a particular party requesting Interconnection under this TO Tariff to the ISO Controlled Grid at the point of interconnection. Direct Assignment Facilities shall be specified in the Interconnection Agreement that governs Interconnection service to such party and shall be subject to FERC approval.

3.18 Dispatch. The operating control of an integrated electric system to: i) assign specific Generation Units and other sources of supply to effect the supply to meet the relevant area Demand taken as Load rises or falls; ii) control operations and

3.23 Energy. The electrical energy produced, flowing, or supplied by generation, transmission, or distribution facilities, being the integral with respect to time of the instantaneous power, measured in units of watt-hours or standard multiples thereof, e.g., 1,000 Wh = 1 kWh, 1,000 kWh = 1 MW, etc.

3.24 Entitlement. The right of a Participating TO obtained through contract or other means to use another entity's transmission facilities for the transmission of Energy.

3.25 Existing Contracts. The contracts which grant transmission service rights in existence on the ISO Operations Date (including any contracts entered into pursuant to such contracts) as may be amended in accordance with their terms or by agreement between the parties thereto from time to time.

3.26 Existing Rights. Those transmission service rights defined in Section 16.1~~2.1.1~~ of the ISO Tariff.

3.27 Expedited Interconnection Agreement. A contract between a party which has submitted a Request for Expedited Interconnection Procedures and the Participating TO under which the Participating TO agrees to process, on an expedited basis, the Completed Interconnection Application of such party and which sets forth the terms, conditions, and cost responsibilities for such interconnection.

3.28 Facilities Study Agreement. An agreement between a Participating TO and either a party requesting Interconnection to the ISO Controlled Grid, Market Participant, Project Sponsor, or identified principal beneficiaries pursuant to which the party requesting such Interconnection, Market Participants, Project Sponsor, or identified principal beneficiaries agrees to reimburse the Participating TO for the cost of performing or reviewing a Facilities Study.

3.29 Facility or Facilities Study. An engineering study conducted to determine required modifications to the Participating TO's transmission system, including the estimated cost and scheduled completion date for such modifications that will be required to provide needed services.

3.30 FERC. The Federal Energy Regulatory Commission, or its successor.

3.31 FPA. The Federal Power Act, 16 U.S.C. § 791a et seq., as it may be amended from time to time.

3.32 [Omitted]~~Firm Transmission Right ("FTR")~~. ~~A contractual right, subject to the terms and conditions of the ISO Tariff, that entitles the FTR Holder to receive, for each hour of the term of the FTR, a portion of the Usage Charges received by the ISO for transportation of energy from a specific originating Zone to a specific receiving Zone and, in the event of an uneconomic curtailment to manage Day-Ahead congestion, to a Day-Ahead scheduling priority higher than that of a schedule using Converted Rights capacity that does not have an FTR.~~

3.33 [Omitted]~~FTR Holder~~. ~~The owner of an FTR, as registered with the ISO.~~

3.34 Generating Unit. An individual electric generator and its associated plant and apparatus whose electrical output is capable of being separately identified and metered or a Physical Scheduling Plant that, in either case, is: (a) located within the ISO Control Area; (b) connected to the ISO Controlled Grid, either directly or via interconnected transmission, or distribution facilities; and (c) that is capable of producing and delivering net Energy (Energy in excess of a generating station's internal power requirements).

Standby Service from the Participating TO or can be curtailed concurrently with an outage of the Generating Unit serving the Load.

3.38 High Voltage Access Charge. A component of the Access Charge determined by the ISO under Section 26.1 of the ISO Tariff.

3.39 High Voltage Transmission Facility. A transmission facility under the operational control of the ISO that is owned by the Participating TO or to which the Participating TO has an Entitlement that may be associated with a Converted Right, which operates at a voltage at or above 200 kilovolts, and supporting facilities, and the costs of which are not directly assigned to one or more specific customers.

3.40 High Voltage Transmission Revenue Requirement. The portion of the Participating TO's TRR associated with and allocable to the Participating TO's High Voltage Transmission Facilities and Converted Rights associated with High Voltage Transmission Facilities.

3.41 High Voltage Utility-Specific Rate. The Participating TO's High Voltage Transmission Revenue Requirement divided by the Participating TO's forecast of its Gross Load.

3.42 High Voltage Wheeling Access Charge. The Wheeling Access Charge assessed by the ISO associated with the recovery of the Participating TO's High Voltage Transmission Revenue Requirement in accordance with Section 26.1 of the ISO Tariff.

3.43 [Omitted].

[Reserved for Future Use]

~~**3.43 Inter-zonal Interface.** The (i) group of transmission paths between two adjacent Zones of the ISO Controlled Grid, for which a physical, non-simultaneous transmission~~

~~capacity rating (the rating of the interface) has been established or will be established prior to the use of the interface for Congestion Management; (ii) the group of transmission paths between an ISO Zone and an adjacent Scheduling Point, for which a physical, non-simultaneous transmission capacity rating (the rating of the interface) has been established or will be established prior to the use of the interface for Congestion Management; or (iii) the group of transmission paths between two adjacent Scheduling Points, where the group of paths has an established transfer capability and established transmission rights.~~

3.44 Interconnection. Transmission facilities, other than additions or replacements to existing facilities that: i) connect one system to another system where the facilities emerge from one and only one substation of the two systems and are functionally separate from the ISO Controlled Grid facilities such that the facilities are, or can be, operated and planned as a single facility; or ii) are identified as radial transmission lines pursuant to contract; or iii) produce Generation at a single point on the ISO Controlled Grid; provided that such interconnection does not include facilities that, if not owned by the Participating TO, would result in a reduction in the ISO's Operational Control of the Participating TO's portion of the ISO Controlled Grid.

3.45 Interconnection Agreement. A contract between a party requesting Interconnection and the Participating TO that owns the transmission facility with which the requesting party wishes to interconnect.

3.46 Interconnection Application. An application that requests Interconnection to the ISO Controlled Grid.

3.47 Interest. Interest shall be calculated in accordance with the methodology costs of which are not directly assigned to one or more specific customers.

3.61 Low Voltage Transmission Revenue Requirement. The portion of the Participating TO's TRR associated with and allocable to the Participating TO's Low Voltage Transmission Facilities and Converted Rights associated with Low Voltage Transmission Facilities.

3.62 Low Voltage Wheeling Access Charge. The Wheeling Access Charge associated with the recovery of the Participating TO's Low Voltage Transmission Revenue Requirement in accordance with Section 26.1 of the ISO Tariff.

3.63 Market Participant. An entity, including a Scheduling Coordinator, who participates in the Energy marketplace through the buying, selling, transmission, or distribution of Energy or Ancillary Services into, out of, or through the ISO Controlled Grid.

3.64 MSS (Metered Subsystem). A geographically contiguous system~~ of a New Participating TO~~, located within a single ~~Z~~zone which has been operating as an electric utility for a number of years prior to the ISO Operations Date as a municipal utility, water district, irrigation district, state agency or federal power marketing authority subsumed within the ISO ~~Control~~ Balancing Authority Area and encompassed by ISO certified revenue quality meters at each interface point with the ISO Controlled Grid and ISO-certified revenue quality meters on all Generating Units or, if aggregated, each individual resource and Participating Load internal to the system, which is operated in accordance with a~~n~~ MSS agreement described in Section ~~10.2.7.1~~4.9.1 of the ISO Tariff.

3.65 NERC. The North American Electric Reliability Council or its successor.

3.66 [Omitted].

3.67 [Omitted].

3.68 New High Voltage Transmission Facility. A High Voltage Transmission Facility of the Participating TO that enters service on or after the Transition Date described in Section 4 of Appendix F, Schedule 3 of the ISO Tariff, or a capital addition made on or after the Transition Date described in Section 4.1 of Appendix F, Schedule 3 of the ISO Tariff to a High Voltage Transmission Facility that existed prior to the Transition Date.

3.69 New Participating TO. A Participating TO that is not an Original Participating TO.

3.70 Non-Participating TO. A TO that is not a party to the TCA or for the purposes of Sections 16.1 ~~and 16.2~~ of the ISO Tariff the holder of transmission service rights under an Existing Contract that is not a Participating TO.

3.71 Non-Spinning Reserve. The portion of off-line generating capacity that is capable of being synchronized and ramping to a specified load in ten minutes (or load that is capable of being interrupted in ten minutes) and that is capable of running (or being interrupted) for at least two hours.

3.72 Operational Control. The rights of the ISO under the Transmission Control Agreement and the ISO Tariff to direct Participating TOs how to operate their transmission lines and facilities and other electric plant affecting the reliability of those lines and facilities for the purpose of affording comparable non-discriminatory transmission access and meeting Applicable Reliability Criteria.

3.73 Original Participating TO. A Participating TO that was a Participating TO as of January 1, 2000. The Original Participating TOs are Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas and Electric Company.

accordance with Section 24 of the ISO Tariff.

3.80 Regional Transmission Group ("RTG"). A voluntary organization approved by FERC and composed of transmission owners, transmission users, and other entities, organized to efficiently coordinate the planning, expansion and use of transmission on a regional and inter-regional basis.

3.81 Regulation. The service provided either by Generating Units certified by the ISO as equipped and capable of ~~operating with AGC which will enable such units to~~ responding to the ISO's direct digital control (AGC) signals, or by System Resources that have been certified by the ISO as capable of delivering such service to the ISO Balancing Authority Area, -in an upward and downward direction to match, on a R~~r~~eal T~~t~~ime basis, Demand and resources, consistent with established NERC and WSCC ~~operating criteria~~reliability standards, including any requirements of the NRC. Regulation is used to control the ~~p~~Power output of electric generators within a prescribed area in response to a change in system frequency, tieline loading, or the relation of these to each other so as to maintain the target system frequency and/or the established I~~i~~nterchange with other Balancing Authority A~~a~~reas within the predetermined Regulation L~~l~~imits. Regulation includes both the increase of output by a Generating Unit or System Resource (Regulation Up) and the decrease in output by a Generating Unit or System Resource (Regulation Down). Regulation Up and Regulation Down are distinct capacity products, with separately stated requirements and ASMPs in each Settlement Period.

3.82 Reliability Criteria. Pre-established criteria that are to be followed in order to maintain desired performance of the ISO Controlled Grid under contingency or steady state conditions.

3.83 Reliability Services Balancing Account ("RSBA"). A mechanism to ensure that all transmission related Reliability Services Costs, as that term is defined in the Master Definitions Supplement, Appendix A to the currently effective ISO Tariff, which are deemed by the ISO as necessary to maintain reliable electric service in the ISO Control Area and whose costs are billed to the Participating TO by the ISO pursuant to the ISO Tariff, are allocated to and received from End-Use Customers, TO Tariff Wholesale Customers, and Existing Contract customers to which PG&E's Reliability Services Tariff (or reliability services-related contract amendments apply), withdrawing Energy from the ISO Controlled Grid on the Participating TO's transmission system.

3.84 Reliability Services Charge. A charge paid by End Use Customers, TO Tariff Wholesale Customers, and Existing Contract customers who take service under the Reliability Services Tariff or a Reliability Services Rate Schedule, whichever is applicable, withdrawing Energy from the ISO Controlled Grid on the Participating TO's transmission system, as set forth in Section 15 of this TO Tariff. The Reliability

Services Charge will recover the Participating TO's reliability services costs, as annually calculated from the balance in the RSBA and a forecast of Reliability Services costs for the following year, from End Use Customers, TO Tariff Wholesale Customers, and Existing Contract customers to which PG&E's Reliability Services Tariff (or reliability services-related contract amendments) applies. In order to mitigate the initial rate increase Wholesale Customers will experience from these Reliability Services Charges, the otherwise applicable Reliability Services Charge will be multiplied by a factor of one-third (1/3) until December 31, 2001, and a factor of two-thirds (2/3) from January 1, 2002 until December 31, 2002. Any Reliability Services costs that are not collected from either TO Tariff Wholesale Customers or Existing Contract customers to which PG&E's Reliability Services Tariff (or reliability services-related contract amendments) applies~~)~~, prior to December 31, 2002, due to the mitigation described above will be allocated to and collected from End Use Customers. Additionally, if FERC, should disallow recovery of any Reliability Services costs from Wholesale Customers those costs shall be included in the allocation to End Use Customers.

3.85 Reliability Upgrade. The transmission facilities, other than Direct Assignment Facilities, beyond the first point of Interconnection necessary to interconnect a wholesale load safely and reliably to the ISO Controlled Grid, which would not have been necessary but for the Interconnection of a wholesale load, including network upgrades necessary to remedy short circuit or stability problems resulting from the interconnection of a wholesale load to the ISO Controlled Grid. Reliability Upgrades also include, consistent with WSCC practice, the facilities necessary to mitigate any adverse impact a wholesale load's interconnection may have on a path's WSCC path rating. Reliability Upgrades shall be specified in the Interconnection Agreement that governs Interconnection service to the wholesale load and shall be subject to FERC approval.

3.86 [Omitted].~~Replacement Reserve.~~ ~~Generating capacity that is dedicated to the ISO, capable of starting up if not already operating, being synchronized to the ISO Controlled Grid, and ramping to a specified load point within a sixty (60) minute period, the output~~

~~of which can be continuously maintained for a two hour period. Also, Curtailable Demand that is capable of being curtailed within sixty minutes and that can remain curtailed for two hours.~~

3.87 Request for Expedited Interconnection Procedures. A written request by which an applicant for Interconnection can request expedited processing of its Interconnection Application.

3.88 Scheduling Coordinator. An entity certified by the ISO for the purposes of undertaking the functions specified in Section 4.5.3 of the ISO Tariff.

3.89 Scheduling Point. A location at which the ISO Controlled Grid or a transmission facility owned by a Transmission Ownership Right holder is connected, by a group of transmission paths for which a physical, non-simultaneous transmission capacity rating has been established for Congestion Management, to transmission facilities that are outside the ISO's Operational Control. ~~A Scheduling Point typically is physically located at an "outside" boundary of the ISO Controlled Grid (e.g., at the point of interconnection between a Control Area utility and the ISO Controlled Grid). For most practical purposes, a Scheduling Point can be considered to be a Zone that is outside the ISO's Controlled Grid.~~

3.90 Standby Service. Service provided by the Participating TO which allows a Standby Service Customer, among other things, access to High Voltage Transmission Facilities for the delivery of backup power on an instantaneous basis to ensure that Energy may be reliably delivered to the Standby Service Customer in the event of an outage of a Generating Unit serving the customer's Load.

3.91 Standby Service Customer. A retail End-Use Customer of the Participating TO that receives Standby Service and pays a Standby Rate.

3.92 Standby Transmission Demand Rate. The Demand portion of a rate assessed a Standby Service Customer by the Participating TO, as approved by the Local Regulatory Authority or FERC, as applicable, for Standby Service which compensates the Participating TO for, among other things, costs of High Voltage Transmission Facilities.

3.93 Standby Transmission Demand Revenue. The transmission revenue associated with the demand portion of Standby Service rates collected by the firm contractual rights to use transmission facilities.

3.103 Transmission Revenue Balancing Account Adjustment ("TRBAA"). A mechanism established by the Participating TO which will ensure that all Transmission Revenue Credits flow through to or are received from End-Use Customers. The TRBAA will also ensure that Transmission Revenue Credits and other credits specified in Section 6, 8, and 13 of Appendix F, Schedule 3 of the ISO Tariff, flow through to other Participating TOs and Wheeling customers for purposes of calculating the High Voltage Access Charge, Low Voltage Access Charge, High Voltage Wheeling Access Charge, Low Voltage Wheeling Access Charge and High Voltage Utility-Specific Access Charge. The 2012 TRBAA will also include an adjustment, if any, for the difference between 1) $10,427,584 and 2) actual revenues received by the Participating TO that are associated with calendar year 2010 and related to transmission for others in accordance with Existing Contracts.

3.104 Transmission Revenue Credit. The proceeds received from the ISO and charges imposed by the ISO that are received and paid by the Participating TO in its role as a Participating TO, as defined by "Transmission Revenue Credit" in the Master Definitions Supplement, Appendix A to the currently effective ISO Tariff.

3.105 Transmission Revenue Requirement ("TRR"). The total annual authorized revenue requirement associated with transmission facilities and Entitlements turned over to the Operational Control of the ISO by the Participating TO. The costs of any transmission facility turned over to the Operational Control of the ISO shall be fully included in the Participating TO's TRR. The TRR is shown in Appendix I.

3.106 Uncontrollable Force. Any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm, flood, earthquake, explosion, any curtailment, order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities or any other cause beyond the reasonable control of the ISO or Market Participant or the PX or PX Participant (as the case may be) which could not be
civilian authorities or any other cause beyond the reasonable control of the ISO or Market Participant or the PX or PX Participant (as the case may be) which could not be

avoided through the exercise of Good Utility Practice.

3.107 Usage Charge. The amount of money, per 1kW of scheduled flow, that the ISO charges a Scheduling Coordinator for use of a specific congested Inter-Zonal Interface during a given hour.

3.108 Utility Distribution Company ("UDC"). An entity that owns a Distribution System for the delivery of Energy to and from the ISO Controlled Grid, and/or that provides regulated retail electric service to End-Users.

3.109 Voltage Support. Services provided by Generating Units or other equipment such as shunt capacitors, static var compensators, or synchronous condensers that are required to maintain established grid voltage criteria. This service is required under normal or system emergency conditions.

3.110 Western System Coordinating Council ("WSCC"). The Western System Coordinating Council or its successor.

3.111 Wheeling Access Charge. The charge assessed by the ISO that is paid by a Scheduling Coordinator for Wheeling in accordance with Section 26.1.4.1 of the ISO Tariff. Wheeling Access Charges shall not apply for Wheeling under a bundled non-economy Energy coordination agreement of a Participating TO executed prior to July 9, 1996. The Wheeling Access Charge consists of a High Voltage Wheeling Access Charge and, if applicable, a Low Voltage Wheeling Access Charge.

3.112 Wheeling Out. Except for Existing Rights exercised under an Existing Contract in accordance with Sections 16.1 ~~and 16.2~~ of the ISO Tariff, the use of the ISO Controlled Grid for the transmission of Energy from a Generating Unit located within the ISO Controlled Grid to serve a Load located outside the transmission and Distribution System of a Participating TO.

3.113 Wheeling Through. Except for Existing Rights exercised under an Existing Contract in accordance with Sections 16.1 ~~and 16.2~~ of the ISO Tariff, the use of the ISO Controlled Grid for the transmission of Energy from a resource located outside the ISO Controlled Grid to serve a Load located outside the transmission and Distribution System of a Participating TO.

3.114 Wheeling. Wheeling Out or Wheeling Through.

3.115 Wholesale Customer. A person wishing to purchase Energy and Ancillary Services at a Bulk Supply Point or a Scheduling Point for resale.

3.116 [Omitted].~~Zone.~~ ~~A portion of the ISO Controlled Grid within which Congestion is expected to be small in magnitude or to occur infrequently. "Zonal" shall be construed accordingly.~~

4. Eligibility. Transmission service over a Participating TO's system shall be provided only to Eligible Customers. Any dispute as to whether an End-Use Customer is eligible for wholesale transmission service shall be resolved by FERC and any dispute as to whether an End-Use Customer is eligible for service under this TO Tariff shall be resolved by the Local Regulatory Authority.

5. Access Charges and Transmission Rates.

5.1 Low Voltage Access Charge. The Low Voltage Access Charge shall be determined in accordance with the ISO Tariff. The Low Voltage Access Charge customer shall pay the Participating TO a Low Voltage Access Charge equal to the product of the Participating TO's Low Voltage Access Charge rate and the kilowatt-hours of transmission service provided under the ISO Tariff to the Low Voltage Access Charge customers. The Participating TO shall not assess the Low Voltage Access Charge to any other Participating TO for transmission service over Low Voltage Transmission Facilities that such other Participating TO receives and pays for under an Existing Contract. Where a customer receives deliveries of energy at voltage levels both above and below 200 kV, the Low Voltage Access Charge shall~~Shell~~ be applied only to

5.5 Transmission Revenue Balancing Account Adjustment ("TRBAA"). The Participating TO shall maintain a Transmission Revenue Balancing Account ("TRBA") that will ensure that all Transmission Revenue Credits associated with transmission service from the ISO are flowed through to or recovered from, as appropriate, customers taking service. The TRBAA shall be equal to:

$$\text{TRBAA} = \text{Cr} + \text{Cf} + \text{I} + \text{FFU}$$

Where:

Cr = The principal balance in the TRBA recorded in FERC Account No. 254 as of September 30 of the year prior to commencement of the January billing cycle. This balance represents the unamortized balance in the TRBA from the previous period and the difference in the amount of revenues or expenditures from Transmission Revenue Credits and the amount of such revenues or expenditures that has been refunded to or collected from customers through operation of the TRBAA, plus an allocation for a three year amortization of ETC Cost Differentials and for purposes of calculating the 2012 TRBAA, the difference between 1) $10,427,584 and 2) actual revenues received by the Participating TO which are associated with calendar year 2010 and are related to transmission for others in accordance with Existing Contracts, will be added to the TRBA on December 31, 2010;

Cf = The forecast of Transmission Revenue Credits for the following calendar year;

I = The interest balance for the TRBA, which shall be calculated using the interest rate pursuant to Section 35.19(a) of FERC's regulations under the Federal Power Act (18 CFR Section 35.19(a)). Interest shall be calculated based on the average TRBA principal balance each month, compounded quarterly; and

FFU = Franchise Fees and Uncollectible Accounts.~~; and~~

APPENDIX I

Transmission and Reliability Services Revenue Requirements [1]

1. **The Transmission Revenue Requirement for purposes of calculating End-User transmission rates shall be $925,582,401~~755,157,256~~, which is composed of the Base Transmission Revenue Requirement of $946,425,145~~776,000,000~~, and the TRBAA of ($20,842,744).[2]**

2. **For purposes of the ISO's calculation of Access Charges under Section 26.1 of the ISO Tariff:**

   a. **The High Voltage Transmission Revenue Requirement shall be $366,491,032~~301,443,169~~, which is composed of a High Voltage Base Transmission Revenue Requirement of $434,012,133~~369,744,597~~, Standby Transmission Demand Revenue credit of ($1,648,424~~2,417,651~~), and a High Voltage TRBAA of ($65,872,678~~65,883,777~~).**

   b. **The Low Voltage Transmission Revenue Requirement shall be $465,444,793~~360,848,710~~, which is composed of a Low Voltage Base Transmission Revenue Requirement of $497,648,749~~393,755,403~~, Standby Transmission Demand Revenue credit of ($1,962,595~~2,676,431~~), and a Low Voltage TRBAA of ($30,241,361~~30,230,262~~).**

   c. **The High Voltage Transmission Revenue Requirement associated with New High Voltage Transmission Facilities is $206,875,128~~166,550,793~~, which is composed of a High Voltage Base Transmission Revenue Requirement of $245,897,227~~205,082,649~~, Standby Transmission Demand Revenue credit of ($933,572~~1,340,105~~), and a High Voltage TRBAA of ($38,088,527~~37,191,751~~).**

   d. **The forecast of Gross Load at the High Voltage/Low Voltage interface is 90,326,715~~94,466,738~~ megawatt-hours.**

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1 Total revenue requirement associated with transmission facilities and entitlements turned over to the operational control of the ISO by the Participating TO, which reflects a reduction or increase for Transmission Revenue Credits.

2 The TRBAA amount includes ($71,411,984) calculated pursuant to Section 5.5 plus $50,569,240 calculated pursuant to Section 5.5.1.

APPENDIX II

Access Charges for Wholesale Transmission

Per kWh

High Voltage Access Charge ……………………………….See ISO Tariff

Low Voltage Access Charge……………………………….. $0.005153~~0.003820~~

High Voltage Utility-Specific Access Charge…………….$0.004057~~0.003191~~

High Voltage Wheeling Access Charge

High Voltage Wheeling Access Charge…………………...See ISO Tariff

Low Voltage Wheeling Access Charge

High Voltage Wheeling Access Charge…………………...See ISO Tariff

Low Voltage Wheeling Access Charge.………………….. $0.005153~~0.003820~~

APPENDIX III

Access Charges for End-Use Service [1, 2]

TABLE OF CONTENTS

[1] These charges represent the rates for recovery of the Base Transmission Revenue Requirement. A TRBAA Rate of ($0.00021) per kWh (Docket No. ER09-34-000) and a TACBAA Rate of ($0.00006) per kWh (Docket No. ER09-376-000) shall also apply to all of the rate schedules described in this Appendix.

[2] The applicability of these rates is described in the California Public Utilities Commission jurisdictional retail tariffs.

RESIDENTIAL SCHEDULES		TO RATES	ECRA RATES
SCHEDULE E-1 **SCHEDULE E-3** **SCHEDULE EL-1 (CARE)** **SCHEDULES E-6 AND EL-6 (CARE)** **SCHEDULES E-7 AND EL-7 (CARE)** **SCHEDULES E-A7 AND EL-A7 (CARE)** **SCHEDULE E-8** **SCHEDULE EL-8 (CARE)** **SCHEDULE E-9**	**SCHEDULE EE** **SCHEDULE EM AND EML (CARE)** **SCHEDULE ES AND ESL (CARE)** **SCHEDULE ESR AND ESRL (CARE)** **SCHEDULE ET AND ETL (CARE)**		
Energy Charges ($/kWh)		$0.01253	($0.00117)

~~**APPENDIX III**~~

~~**Access Charges for End-Use Service**~~

~~**Table of Contents**~~

~~**[1] These charges represent the rates for recovery of the Base Transmission Revenue Requirement.**~~
~~**A TRBAA Rate of ($0.00021) per kWh and a TACBAA Rate of ($0.00006) per kWh**~~
~~**shall also apply to all of the rate schedules described in this Appendix.**~~

~~**[2] The applicability of these rates is described in the California Public Utilities Commission jurisdictional retail tariffs.**~~

~~**RESIDENTIAL SCHEDULES**~~		~~TO RATES~~	~~ECRA RATES~~
~~**SCHEDULE E-1**~~	~~**SCHEDULE EE**~~		
~~**SCHEDULE E-3**~~	~~**SCHEDULE EM AND EML (CARE)**~~		
~~**SCHEDULE EL-1 (CARE)**~~	~~**SCHEDULE ES AND ESL (CARE)**~~		
~~**SCHEDULES E-6 AND EL-6 (CARE)**~~	~~**SCHEDULE ESR AND ESRL (CARE)**~~		
~~**SCHEDULES E-7 AND EL-7 (CARE)**~~	~~**SCHEDULE ET AND ETL (CARE)**~~		
~~**SCHEDULES E-A7 AND EL-A7 (CARE)**~~			
~~**SCHEDULE E-8**~~			
~~**SCHEDULE EL-8 (CARE)**~~			
~~**SCHEDULE E-9**~~			
~~Energy Charge ($/kWh)~~		~~$0.01006~~	~~($0.00117)~~

COMMERCIAL & INDUSTRIAL SCHEDULES	TO RATES	ECRA RATES
SCHEDULE A-1 **SCHEDULE A-6** **SCHEDULE A-15** **SCHEDULE TC-1**		
Energy Charges ($/kWh)	$0.01171	($0.00110)

SCHEDULE A-10

BASIS FOR DEMAND CHARGE: The customer will be billed for demand according to the customer's "maximum demand" each month. The number of kW used will be recorded over 15-minute intervals; the highest 15-minute average in the month will be the customer's maximum demand. SPECIAL CASES: (1) If the customer's use of energy is intermittent or subject to severe fluctuations, a 5-minute interval may be used, and (2) If the customer uses welders, the demand charge will be subject to the minimum demand charges for those welders' ratings, as explained in Section J of PG&E's CPUC Rule 2.

	TO RATES	ECRA RATES
Maximum Demand Charge ($/kW/mo)	$4.01	
Energy Charges ($/kWh)		($0.00098)

SCHEDULE E-19

BASIS FOR DEMAND CHARGE: Demand will be averaged over 15-minute intervals for customers whose maximum demand exceeds 499 kW. "Maximum demand" will be the highest of all the 15-minute averages for the billing month. If the customer's use of electricity is intermittent or subject to severe fluctuations, a 5-minute interval may be used. If the customer has any welding machines, the diversified resistance welder load, calculated in accordance with Section J of PG&E's CPUC Rule 2, will be considered the maximum demand if it exceeds the maximum demand that results from averaging the demand over 15-minute intervals. The customer's maximum-peak-period demand will be the highest of all the 15-minute averages for the peak period during the billing month.

- This schedule has three demand charges, a maximum-peak-period-demand charge, a maximum-part-peak-period and a maximum demand charge. The maximum-peak-period demand charge per kilowatt applies to the maximum demand during the month's peak hours, the maximum part-peak-period demand charge applies to the maximum demand during the month's part-peak hours, and the maximum demand charge per kilowatt applies to the maximum demand at any time during the month. The bill will include all of these demand charges.
- The monthly charges may be increased or decreased based upon the power factor.

POWER FACTOR ADJUSTMENTS: Bills will be adjusted based on the power factor for all customers except those selecting voluntary E-19 service. The power factor is computed from the ratio of lagging reactive kilovolt-ampere-hours to the kilowatt-hours consumed in the month. Power factors are rounded to the nearest whole percent.

The rates in this rate schedule are based on a power factor of 85 percent. If the average power factor is greater than 85 percent, the total monthly bill will be reduced by the product of the power factor rate and the kilowatt-hour usage for each percent.

For customers taking Non-Firm Service, power factor adjustments will be applied to the customer's total bill, net of charges and credits billed under Schedule E-NF.

	TO RATES	ECRA RATES
SCHEDULE E-19 Demand Charges ($/kW/mo)	$4.01	
Energy Charges ($/kWh)		($0.00098)

~~**COMMERCIAL & INDUSTRIAL SCHEDULES**~~	~~TO RATES~~	~~ECRA RATES~~
~~**SCHEDULE A-1**~~		
~~**SCHEDULE A-6**~~		
~~**SCHEDULE A-15**~~		
~~**SCHEDULE TC-1**~~		
~~Energy Charges ($/kWh)~~	~~$0.00952~~	~~($0.00110)~~

~~**Schedule A-10**~~

~~BASIS FOR DEMAND CHARGE: The customer will be billed for demand according to the customer's "maximum demand" each month. The number of kW used will be recorded over 15-minute intervals; the highest 15-minute average in the month will be the customer's maximum demand. SPECIAL CASES: (1) If the customer's use of energy is intermittent or subject to severe fluctuations, a 5-minute interval may be used, and (2) If the customer uses welders, the demand charge will be subject to the minimum demand charges for those welders' ratings, as explained in Section J of PG&E's CPUC Rule 2.~~

~~Maximum Demand Charge ($/kW/mo)~~	~~$2.96~~	
~~Energy Charge ($/kWh)~~		~~(0.00098)~~

~~**Schedule E-19**~~

~~BASIS FOR DEMAND CHARGE: Demand will be averaged over 15-minute intervals for customers whose maximum demand exceeds 499 kW. "Maximum demand" will be the highest of all the 15-minute averages for the billing month. If the customer's use of electricity is intermittent or subject to severe fluctuations, a 5-minute interval may be used. If the customer has any welding machines, the diversified resistance welder load, calculated in accordance with Section J of PG&E's CPUC Rule 2, will be considered the maximum demand if it exceeds the maximum demand that results from averaging the demand over 15-minute intervals. The customer's maximum-peak-period demand will be the highest of all the 15-minute averages for the peak period during the billing month.~~

- ~~This schedule has three **demand charges**, a maximum-peak-period-demand charge, a maximum-part-peak-period and a maximum demand charge. The maximum-peak-period demand charge per kilowatt applies to the maximum demand during the month's peak hours, the maximum part-peak-period demand charge applies to the maximum demand during the month's part-peak hours, and the maximum demand charge per kilowatt applies to the maximum demand at any time during the month. The bill will include all of these demand charges.~~
- ~~The monthly charges may be increased or decreased based upon the power factor.~~

~~POWER FACTOR ADJUSTMENTS: Bills will be adjusted based on the power factor for all customers except those selecting voluntary E-19 service. The power factor is computed from the ratio of lagging reactive kilovolt-ampere-hours to the kilowatt-hours consumed in the month. Power factors are rounded to the nearest whole percent.~~

~~The rates in this rate schedule are based on a power factor of 85 percent. If the average power factor is greater than 85 percent, the total monthly bill will be reduced by the product of the power factor rate and the kilowatt-hour usage for each percent~~

~~For customers taking Non-Firm Service, power factor adjustments will be applied to the customer's total bill, net of charges and credits billed under Schedule E-NF.~~

~~**Schedule E-19** Demand Charges ($/kW/mo)~~	~~$2.96~~	
~~Energy Charges ($/kWh)~~		~~(0.00098)~~

	TO RATES	ECRA RATES
SCHEDULE E-20		

BASIS FOR DEMAND CHARGE: Demand will be averaged over 15-minute intervals. "Maximum demand" will be the highest of all the 15-minute averages for the billing month. If the customer's use of electricity is intermittent or subject to severe fluctuations, a 5-minute interval may be used. If the customer has any welding machines, the diversified resistance welder load, calculated in accordance with Section J of PG&E's CPUC Rule 2, will be considered the maximum demand if it exceeds the maximum demand that results from averaging the demand over 15-minute intervals. The customer's maximum-peak-period demand will be the highest of all the 15-minute averages for the peak period during the billing month.

- Schedule E-20 has three demand charges, a maximum-peak-period demand charge, a maximum-part-peak-period demand charge, and a maximum-demand charge. The maximum-peak-period demand charge per kilowatt applies to the maximum demand during the month's peak hours, the maximum-part-peak demand charge applies to the maximum demand during the month's part-peak hours, and the maximum demand charge per kilowatt applies to the maximum demand at any time during the month. The bill will include all of these demand charges.
- The monthly charges may be increased or decreased based upon the power factor, using the same method as described above for Schedule E-19.

	TO RATES	ECRA RATES
SCHEDULE E-20 Demand Charges ($/kW/mo)	$4.06	
Energy Charges ($/kWh)		($0.00081)
SCHEDULE E-37		
Energy Charges ($/kWh)	$0.00932	($0.00081)
SCHEDULE S		

RESERVATION CAPACITY: The Reservation Capacity to be used for billing under the above rates shall be as set forth in the customer's contract for service. For new or revised contracts, the Reservation Capacity shall be determined by the customer. However, if the customer's standby demand exceeds this new contracted capacity in any billing month, that standby demand shall become the new Reservation or Contract Capacity for 12 months, beginning with that month. See Special Condition 7 for the definition of Reservation Capacity for Supplemental Standby Service customers.

The **Reservation Charge**, in dollars per kilowatt (kW), applies to 85 percent of the customer's Reservation Capacity, as defined in Special Condition 1 of the tariffs.

POWER FACTOR ADJUSTMENT: When the customer's Reservation Capacity is greater than 500 kW, the bill will be adjusted based on the power factor. The power factor is derived from the ratio of kWh to kVAh consumed in the month. Power factors are averaged and rounded to the nearest whole percent.

The rates in this rate schedule are based on a power factor of 85 percent. If the average power factor is greater than 85 percent, the total monthly bill will be reduced by the product of the power factor adjustment rate and the kilowatt-hour usage for each percentage point above 85 percent. If the average power factor is less than 85 percent, the total monthly bill will be increased by the product of the power factor adjustment rate and the kilowatt-hour usage for each percentage point below 85 percent.

The customer shall pay only the greater of the power factor adjustment and the reactive demand charge.

Generators for which ISO standards apply must also meet power factor requirements specified in the ISO tariff.

	TO RATES	ECRA RATES
Energy Charges ($/kWh)	$0.00859	($0.00309)
Reservation Charge ($/kW/mo)	$0.48	

	~~TO RATES~~	~~ECRA RATES~~
~~**Schedule E-20**~~		

~~BASIS FOR DEMAND CHARGE: Demand will be averaged over 15-minute intervals. "Maximum demand" will be the highest of all the 15-minute averages for the billing month. If the customer's use of electricity is intermittent or subject to severe fluctuations, a 5-minute interval may be used. If the customer has any welding macines, the diversified resistance welder load, calculated in accordance with Section J of PG&E's CPUC Rule 2, will be considered the maximum demand if it exceeds the maximum demand that results from averaging the demand over 15-minute intervals. The customer's maximum-peak-period demand will be the highest of all the 15-minute averages for the peak period during the billing month.~~

– ~~Schedule E-20 has three **demand charges**, a maximum-peak-period demand charge, a maximum-part-peak-period demand charge, and a maximum-demand charge. The maximum-peak-period demand charge per kilowatt applies to the maximum demand during the month's peak hours, the maximum-part-peak demand charge applies to the maximum demand during the month's part-peak hours, and the maximum demand charge per kilowatt applies to the maximum demand at any time during the month. The bill will include all of these demand charges.~~

– ~~The monthly charges may be increased or decreased based upon the power factor, using the same method as described above for Schedule E-19.~~

~~**Schedule E-20** Demand Charges ($/kW/mo)~~	~~$3.22~~	
~~Energy Charges ($/kWh)~~		~~($0.00081)~~
~~**Schedule E-37**~~		
~~Energy Charges ($/kWh)~~	~~$0.00699~~	~~($0.00081)~~

~~**Schedule S**~~

~~RESERVATION CAPACITY: The Reservation Capacity to be used for billing under the above rates shall be as set forth in the customer's contract for service. For new or revised contracts, the Reservation Capacity shall be determined by the customer. However, if the customer's standby demand exceeds this new contracted capacity in any billing month, that standby demand shall become the new Reservation or Contract Capacity for 12 months, beginning with that month. See Special Condition 7 for the definition of Reservation Capacity for Supplemental Standby Service customers.~~

~~The **Reservation Charge**, in dollars per kilowatt (kW), applies to 85 percent of the customer's Reservation Capacity, as defined in Special Condition 1 of the tariffs.~~

~~POWER FACTOR ADJUSTMENT: When the customer's Reservation Capacity is greater than 500 kW, the bill will be adjusted based on the power factor. The power factor is derived from the ratio of kWh to kVAh consumed in the month. Power factors are averaged and rounded to the nearest whole percent.~~

~~The rates in this rate schedule are based on a power factor of 85 percent. If the average power factor is greater than 85 percent, the total monthly bill will be reduced by the product of the power factor adjustment rate and the kilowatt-hour usage for each percentage point above 85 percent. If the average power factor is less than 85 percent, the total monthly bill will be increased by the product of the power factor adjustment rate and the kilowatt-hour usage for each percentage point below 85 percent.~~

~~The customer shall pay only the greater of the power factor adjustment and the reactive demand charge.~~

~~Generators for which ISO standards apply must also meet power factor requirements specified in the ISO tariff.~~

~~**Schedule S**~~		
~~Energy Charges ($/kWh)~~	~~$0.01332~~	~~($0.00309)~~
~~Reservation Charge ($/kW/mo)~~	~~$0.38~~	

AGRICULTURAL SCHEDULES	TO RATES	ECRA RATES
The CPUC-jurisdictional retail tariffs should be referred to for detailed descriptions of how agricultural demand charges are assessed.		
SCHEDULE AG-1 **SCHEDULE AG-R** **SCHEDULE AG-V** **SCHEDULE AG-4** **SCHEDULE AG-5** **SCHEDULE AG-ICE**		
Energy Charges ($/kWh)	$0.00932	($0.00081)

STREETLIGHTING SCHEDULES		
SCHEDULE LS-1 **SCHEDULE LS-2** **SCHEDULE LS-3** **SCHEDULE OL-1**		
Energy Charges ($/kWh)	$0.00504	($0.00069)

~~AGRICULTURAL SCHEDULES~~	~~TO RATES~~	~~ECRA RATES~~
~~The CPUC- jurisdictional retail tariffs should be referred to for detailed descriptions of how agricultural demand charges are assessed.~~		
~~**SCHEDULE AG-1**~~ ~~**SCHEDULE AG-R**~~ ~~**SCHEDULE AG-V**~~ ~~**SCHEDULE AG-4**~~ ~~**SCHEDULE AG-5**~~ ~~**SCHEDULE AG-ICE**~~		
~~Energy Charges ($/kWh)~~	~~$0.00699~~	~~($0.00081)~~

~~STREETLIGHTING SCHEDULES~~		
~~**SCHEDULE LS-1**~~ ~~**SCHEDULE LS-2**~~ ~~**SCHEDULE LS-3**~~ ~~**SCHEDULE OL-1**~~		
~~Energy Charge ($/kWh)~~	~~$0.00594~~	~~($0.00069)~~

PG&E Gas and Electric
Advice Filing List
General Order 96-B, Section IV

Alcantar & Kahl
Ameresco
Anderson & Poole
Arizona Public Service Company
BART
BP Energy Company
Barkovich & Yap, Inc.
Bartle Wells Associates
C & H Sugar Co.
CA Bldg Industry Association
CAISO
CLECA Law Office
CSC Energy Services
California Cotton Ginners & Growers Assn
California Energy Commission
California League of Food Processors
California Public Utilities Commission
Calpine
Cameron McKenna
Cardinal Cogen
Casner, Steve
Chamberlain, Eric
Chevron Company
Chris, King
City of Glendale
City of Palo Alto
City of San Jose
Clean Energy Fuels
Coast Economic Consulting
Commerce Energy
Commercial Energy
Consumer Federation of California
Crossborder Energy
Davis Wright Tremaine LLP
Day Carter Murphy
Defense Energy Support Center
Department of Water Resources
Department of the Army
Dept of General Services
Division of Business Advisory Services
Douglas & Liddell
Douglass & Liddell
Downey & Brand
Duke Energy
Dutcher, John
Ellison Schneider & Harris LLP
FPL Energy Project Management, Inc.
Foster Farms
G. A. Krause & Assoc.
GLJ Publications
Goodin, MacBride, Squeri, Schlotz & Ritchie
Green Power Institute
Hanna & Morton
Hitachi
International Power Technology
Intestate Gas Services, Inc.
Los Angeles Dept of Water & Power
Luce, Forward, Hamilton & Scripps LLP
MBMC, Inc.
MRW & Associates
Manatt Phelps Phillips
Matthew V. Brady & Associates
McKenzie & Associates
Merced Irrigation District
Mirant
Modesto Irrigation District
Morgan Stanley
Morrison & Foerster
New United Motor Mfg., Inc.
Norris & Wong Associates
North Coast SolarResources
Northern California Power Association
Occidental Energy Marketing, Inc.
OnGrid Solar
Praxair
R. W. Beck & Associates
RCS, Inc.
Recon Research
SCD Energy Solutions
SCE
SMUD
SPURR
Santa Fe Jets
Seattle City Light
Sempra Utilities
Sierra Pacific Power Company
Silicon Valley Power
Southern California Edison Company
Sunshine Design
Sutherland, Asbill & Brennan
Tabors Caramanis & Associates
Tecogen, Inc.
Tiger Natural Gas, Inc.
Tioga Energy
TransCanada
Turlock Irrigation District
U S Borax, Inc.
United Cogen
Utility Cost Management
Utility Specialists
Verizon
Wellhead Electric Company
Western Manufactured Housing Communities Association (WMA)
eMeter Corporation