Pacific Gas and Electric Company®

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November 13, 2009

Advice 3558-E
(Pacific Gas and Electric Company ID U 39 E)

<u>Subject:</u> **Revision to Demand Response Tariffs in Compliance with Decision 09-08-027**

Public Utilities Commission of the State of California

Pacific Gas and Electric Company (PG&E) hereby submits revisions to various electric demand response (DR) tariffs. The affected sheets are included as Attachment 1.

Purpose and Background

On August 20, 2009, the Commission issued Decision (D.) 09-08-027 (Decision) adopting DR activities and budgets for 2009 through 2011. The Decision approved utility DR programs, funding, and cost recovery mechanisms.

In compliance with the Decision, PG&E proposes revisions to the tariff language in PG&E's DR rate schedules E–BIP - *Base Interruptible Program*, E-DBP – *Demand Bidding Program*, E-SLRP – *Scheduled Load Reduction Program*, E-OBMC - *Optional Binding Mandatory Curtailment Program*, E-CBP – *Capacity Bidding Program*, E-CPP - *Critical Peak Pricing Program*, E-PEAKCHOICE – *PeakChoice*, and Electric Preliminary Statement Part EC – *Demand Response Expenditures Balancing Account (DREBA)*.

The tariff changes include the following: 1) adding language capping emergency-triggered DR programs at their enrolled megawatts on August 20, 2009 as ordered by the Commission; 2) revising E-OBMC to include customers terminated in E-POBMC – Pilot Optional Binding Mandatory Curtailment Program; 3) eliminating direct-enrollment of customer in E-CBP; 4) changing the notification time in the PeakChoice program from noon to no later that 2:00 p.m. for notification on days preceding an event; 5) revising the DR program baselines to a 10-day individual baseline with the option of a day-of adjustment; 6) modifying the eligibility of certain DR programs to allow partial standby customers to participate, 7) removing language in E-CBP requiring Aggregator notification of ESPs of its DA customers as the utility will provide this notice; 8) removing and updating outdated language in E-CPP and E-DBP regarding Technical Assistance and Technology Incentives (TA/TI); 9) deleting references to the San Francisco Community Power (SFCP) Small Commercial Pilot Program in E-CBP as the pilot is terminated; and 10) adding two-way balancing account treatment for event-based program incentives in DREBA.

In addition, in compliance with the Decision, PG&E proposes to 1) terminate the E-POBMC and E-BEC – Business Energy Coalition program rate schedules and 2) eliminate form 79-1074 – Agreement for Customers Participating Directly in the Capacity Bidding Program.

Revisions to Existing Rate Schedules and Standard Forms

In compliance with D.09-08-027, PG&E proposes to make the following changes to its DR rate schedules:

Schedule E-BIP – Base Interruptible Program

- Add language specifying the program enrollment is capped at its current enrolled megawatts

Schedule E-DBP – Demand Bidding Program

- Adopt a new 10-day methodology for calculating settlement baselines, with an opt-in day-of adjustment. The day-of adjustment is capped at +/- 20 percent and is based on the first three of the four hours prior to the event.
- Remove and update outdated language regarding TA/TI

Schedule E-SLRP – Scheduled Load Reduction Program

- Add language specifying the program enrollment is capped at its current enrolled megawatts

Schedule E-OBMC – Optional Binding Mandatory Curtailment Program

- Add language specifying the program enrollment is capped at its current enrolled megawatts
- Adopt a new 10-day methodology for calculating settlement baselines, with an opt-in day-of adjustment. The day-of adjustment is capped at +/- 20 percent and is based on the first three of the four hours prior to the event.

Schedule E-CBP – Capacity Bidding Program

- Eliminate language allowing customers to directly enroll in the program
- Add language to allow customers taking partial standby service to participate in the program

- Adopt a new 10-day methodology for calculating settlement baselines, with an opt-in day-of adjustment. The day-of adjustment is capped at +/- 20 percent and is based on the first three of the four hours prior to the event.
- Removed outdated language stating that an Aggregator will notify Energy Service Provider (ESP) of its Direct Access (DA) customers when a CBP event has been scheduled. As part of the "Joint Status Report on Energy Service Provider Issues" filed on December 22, 2008, in compliance with the Scoping Memo of this proceeding, this issue was resolved and the utilities agreed to provide an ESP a list of DA customers enrolled in CBP on a monthly basis.
- Removed paragraph referencing the San Francisco Community Power (SFCP) Small Commercial Pilot Program, as the Commission approved the termination of this program effective November 30, 2009

Schedule E-CPP – Critical Peak Pricing Program

- Add language to allow customers taking partial standby service to participate in the program
- Remove and update outdated language regarding TA/TI

Schedule E-PEAKCHOICE – PeakChoice Program

- Add language to allow customers taking partial standby service to participate in the program
- Modify the event notification time to no later that 2:00 p.m. the day preceding an event to align with the California Independent System Operator (CAISO) market
- Adopt a new 10-day methodology for calculating settlement baselines, with an opt-in day-of adjustment. The day-of adjustment is capped at +/-20 percent and is based on the first three of the four hours prior to the event.

Schedule E-POBMC – Pilot Optional Binding Mandatory Curtailment Program

- Eliminate this rate schedule as authorized in the Decision on page 41 and Ordering Paragraph 3

Schedule E-BEC – Business Energy Coalition Program

- Eliminate this rate schedule as authorized in the Decision. As ordered in Ordering Paragraph 7, this program will be eliminated effective on November 18, 2009, which is within 90 days of the effective date of this decision.

Form 79-1074 – Agreement for Customers Participating Directly in the Capacity Bidding Program

- Eliminate this agreement as customers will no longer be allowed to directly enroll in this program as authorized in the Decision

Revisions to Existing Preliminary Statements

In compliance with Ordering Paragraph 37, the following changes allow two-way balancing account treatment for DR event-based program incentives effective January 1, 2009[1]:

Electric Preliminary Statement EC - Demand Response Expenditures Balancing Account

- Add one new, two-way balancing subaccount titled "Incentives" to DREBA to record the authorized budget and participation incentives paid to customers associated with event-based demand response programs. As a result of this change, another subaccount one-way "Operations" has been added to incorporate all other accounting procedures already authorized in the DREBA.

Protest Period

Anyone wishing to protest this filing may do so by sending a letter by **December 3, 2009**, which is **20** days from the date of this filing. The protest must state the grounds upon which it is based, including such items as financial and service impact, and should be submitted expeditiously. 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

[1] The total program budgets for 2009-2011 adopted by D.09-08-027 included 2009 amounts previously approved in the Bridge Funding Decision D.08-12-038. Ordering Paragraph 5 of D.08-12-038 states that when a final decision for 2009-2011 programs is adopted, the IOUs shall adjust their applicable demand response balancing accounts to reflect the demand response revenue requirement authorized in that decision effective January 1, 2009.

Copies of protests also should be mailed to the attention of the Director, Energy 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
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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 and tariff changes, unless specifically noted above, become effective on regular notice, **January 1, 2010**, which is YY calendar days after the date of filing.

Notice

In accordance with General Order 96-B, Section IV, a copy of this Advice Letter is being sent electronically or via U.S. mail to parties shown on the attached list and to the service lists for A.08-06-003 and R.07-01-041. Address changes and electronic approvals should be directed to e-mail PGETariffs@pge.com. Advice Letter filings can also be accessed electronically at: http://www.pge.com/ tariffs.

Brian Cherry / [illegible]

Vice President - Regulatory Relations

Attachments

cc: Service Lists – A.08-06-003 and R.07-01-041

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: Linda Tom-Martinez

Phone #: (415) 973-4612

E-mail: lmt1@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) #: **3558-E** **Tier:** 2

Subject of AL: **Revision to Demand Response Tariffs in Compliance with Decision 09-08-027**

Keywords (choose from CPUC listing): Forms, Curtailable Service

AL filing type: ☐ Monthly ☐ Quarterly ☐ Annual ☑ One-Time ☐ Other ____________

If AL filed in compliance with a Commission order, indicate relevant Decision/Resolution #: D.09-08-027

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

Summarize differences between the AL and the prior withdrawn or rejected AL[1]: ____________

Is AL requesting confidential treatment? If so, what information is the utility seeking confidential treatment for:

Confidential information will be made available to those who have executed a nondisclosure agreement: ☐ Yes ☐ No

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

Resolution Required? ☐Yes ☑ No

Requested effective date: **January 1, 2010** No. of tariff sheets: 35

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).

Tariff schedules affected: Electric Rate Schedules E-PeakChoice, E-BIP, E-OBMC, E-SLRP, E-DBP, E-CPP, E-CBP, E-POBMC, E-BEC, Electric Preliminary Statement EC, Electric Form 79-1074

Service affected and changes proposed[1]: N/A

Pending advice letters that revise the same tariff sheets: 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

Cal P.U.C. Sheet No.	**Title of Sheet**	**Cancelling Cal P.U.C. Sheet No.**
28614-E	ELECTRIC PRELIMINARY STATEMENT PART EC DEMAND RESPONSE EXPENDITURES BALANCING ACCOUNT Sheet 1	27867-E
28615-E	ELECTRIC PRELIMINARY STATEMENT PART EC DEMAND RESPONSE EXPENDITURES BALANCING ACCOUNT Sheet 2	27868-E
28616-E	ELECTRIC PRELIMINARY STATEMENT PART EC DEMAND RESPONSE EXPENDITURES BALANCING ACCOUNT Sheet 3	
28617-E	ELECTRIC SCHEDULE E-PEAKCHOICE PEAKCHOICE Sheet 1	27318-E
28618-E	ELECTRIC SCHEDULE E-PEAKCHOICE PEAKCHOICE Sheet 3	27320-E
28619-E	ELECTRIC SCHEDULE E-PEAKCHOICE PEAKCHOICE Sheet 4	27321-E
28620-E	ELECTRIC SCHEDULE E-BIP BASE INTERRUPTIBLE PROGRAM Sheet 1	28413-E
28621-E	ELECTRIC SCHEDULE E-OBMC OPTIONAL BINDING MANDATORY CURTAILMENT PLAN Sheet 1	18839-E
28622-E	ELECTRIC SCHEDULE E-OBMC OPTIONAL BINDING MANDATORY CURTAILMENT PLAN Sheet 2	18840-E*

Cal P.U.C. Sheet No.	**Title of Sheet**	**Cancelling Cal P.U.C. Sheet No.**
28623-E	ELECTRIC SCHEDULE E-OBMC OPTIONAL BINDING MANDATORY CURTAILMENT PLAN Sheet 3	18429-E
28624-E	ELECTRIC SCHEDULE E-SLRP SCHEDULED LOAD REDUCTION PROGRAM Sheet 1	27284-E
28625-E	ELECTRIC SCHEDULE E-DBP DEMAND BIDDING PROGRAM Sheet 3	27280-E
28626-E	ELECTRIC SCHEDULE E-DBP DEMAND BIDDING PROGRAM Sheet 4	27281-E
28627-E	ELECTRIC SCHEDULE E-DBP DEMAND BIDDING PROGRAM Sheet 5	25686-E*
28628-E	ELECTRIC SCHEDULE E-DBP DEMAND BIDDING PROGRAM Sheet 6	27282-E
28629-E	ELECTRIC SCHEDULE E-DBP DEMAND BIDDING PROGRAM Sheet 7	25688-E
28630-E	ELECTRIC SCHEDULE E-DBP DEMAND BIDDING PROGRAM Sheet 8	28419-E
28631-E	ELECTRIC SCHEDULE E-DBP DEMAND BIDDING PROGRAM Sheet 9	27283-E
28632-E	ELECTRIC SCHEDULE E-DBP DEMAND BIDDING PROGRAM Sheet 10	
28633-E	ELECTRIC SCHEDULE E-CPP CRITICAL PEAK PRICING PROGRAM Sheet 1	27287-E
28634-E	ELECTRIC SCHEDULE E-CPP CRITICAL PEAK PRICING PROGRAM Sheet 6	27290-E

Cal P.U.C. Sheet No.	Title of Sheet	Cancelling Cal P.U.C. Sheet No.
28635-E	ELECTRIC SCHEDULE E-CBP CAPACITY BIDDING PROGRAM Sheet 1	27217-E
28636-E	ELECTRIC SCHEDULE E-CBP CAPACITY BIDDING PROGRAM Sheet 2	27218-E*
28637-E	ELECTRIC SCHEDULE E-CBP CAPACITY BIDDING PROGRAM Sheet 3	28272-E
28638-E	ELECTRIC SCHEDULE E-CBP CAPACITY BIDDING PROGRAM Sheet 4	27872-E
28639-E	ELECTRIC SCHEDULE E-CBP CAPACITY BIDDING PROGRAM Sheet 5	25935-E
28640-E	ELECTRIC SCHEDULE E-CBP CAPACITY BIDDING PROGRAM Sheet 7	28428-E
28641-E	ELECTRIC SCHEDULE E-CBP CAPACITY BIDDING PROGRAM Sheet 8	28274-E
28642-E	ELECTRIC SCHEDULE E-CBP CAPACITY BIDDING PROGRAM Sheet 9	27219-E
28643-E	ELECTRIC SCHEDULE E-CBP CAPACITY BIDDING PROGRAM Sheet 10	28275-E
28644-E	ELECTRIC SCHEDULE E-CBP CAPACITY BIDDING PROGRAM Sheet 11	27873-E
28645-E	ELECTRIC TABLE OF CONTENTS Sheet 1	28429-E
28646-E	ELECTRIC TABLE OF CONTENTS RATE SCHEDULES Sheet 5	28430-E

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28647-E	ELECTRIC TABLE OF CONTENTS PRELIMINARY STATEMENT Sheet 9	28565-E
28648-E	ELECTRIC TABLE OF CONTENTS SAMPLE FORMS Sheet 17	28280-E

ELECTRIC PRELIMINARY STATEMENT PART EC

DEMAND RESPONSE EXPENDITURES BALANCING ACCOUNT

Sheet 1

EC. Demand Response Expenditures Balancing Account (DREBA)

1. PURPOSE: The purpose of the Demand Response Expenditure Balancing Account (DREBA) is to track the authorized demand response program budget compared to costs incurred by PG&E to implement and administer PG&E's authorized demand response programs. Actual costs to operate the programs include Operating and Maintenance (O&M), including customer incentives, and Administrative and General (A&G) expenses and capital-related revenue requirements incurred to develop and implement, or in reasonable anticipation of implementing authorized demand response programs. (T)

2. APPLICABILITY: The DREBA shall apply to all customer classes, except those specifically excluded by the Commission.

3. REVISION DATE: The revision dates applicable to the DREBA shall be determined as necessary in the Annual Electric True-Up (AET) process or other filing as authorized by the Commission. (T)

4. RATES: The DREBA does not have a rate component.

5. ACCOUNTING PROCEDURE: The DREBA consists of two sub-accounts: (T)

   The "Operations Sub-account" is a one-way balancing account that tracks the annual authorized program budget, excluding event based participation incentives, compared to costs incurred to operate, maintain, and administer demand response programs, as well as ongoing capital-related revenue requirements. Disposition of any remaining balance in this sub-account, once all authorized budget cycle program costs have been recorded, will be determined in the AET or other proceeding authorized by the Commission. (N)

   The "Incentives Sub-account" is a two-way balancing account that records PG&E's authorized event based participation incentives budget compared to costs incurred for payment of incentives to participating customers. Disposition of the balance in this sub-account is annually through the AET process or other filing as authorized. (N)

   A. Operations Sub-Account

      The following entries shall be made at the end of each month:

      1) A debit entry equal to O&M, excluding incentives, and A&G expenses incurred to develop and implement, or incurred in reasonable anticipation of implementing, authorized demand response programs; (T)

      2) A credit entry equal to one-twelfth of the current year demand response program budget, excluding the event based participation incentives portion of the authorized budget, as authorized by the CPUC; (T)

(Continued)

ELECTRIC PRELIMINARY STATEMENT PART EC

Sheet 2

DEMAND RESPONSE EXPENDITURES BALANCING ACCOUNT

EC. Demand Response Expenditures Balancing Account (DREBA) (Cont'd.)

3) A debit entry for capital-related revenue requirements associated with authorized demand response programs, equal to:

a. Depreciation expense on the average of the beginning and the end-of-month balance of plant installed for each program at one-twelfth of the annual depreciation rates approved by the CPUC for these plant accounts; plus

b. The return on investment on the average of the beginning and the end-of-month balance of plant installed for each program at one-twelfth of the annual rate of return on distribution investment last adopted for PG&E's Electric Department by the CPUC; less

c. The return on the average of beginning and end-of-month accumulated depreciation, and on average accumulated net of deferred taxes on income resulting from the normalization of federal tax depreciation, at one-twelfth the annual rate of return on distribution investment last adopted for PG&E Electric Department by the CPUC.

4) A debit entry equal to federal and state taxes based on income associated with Item 5.d. above, calculated at marginal tax rates currently in effect. This will include all applicable statutory adjustments.

For federal and state taxes, this will conform to normalization requirements as applicable. Interest cost will be at the percentage of net investment last adopted by the CPUC with respect to PG&E.

5) A debit entry equal to the monthly property taxes on the plant installed;

6) A credit entry equal to all enrollment fees, equipment fees, non-compliance or contractual non-performance penalties paid by customers participating in demand response programs;

7) A debit or credit entry to transfer amounts in this account to other accounts, or amounts from other accounts to this account upon approval by the Commission; and

8) A debit entry equal to the interest on the average of the balance at the beginning of the month and the balance after the above entries at a rate equal to one-twelfth the interest rate on three-month Commercial Paper for the previous month, as reported in the Federal Reserve Statistical Release, H.15 or its successor.

B. Incentives Sub-Account (N)

The following entries will be made to this sub-account at the end of each month:

1) A credit entry equal to one-twelfth of the current year demand response program budget associated with event based incentives, as authorized by the CPUC;

2) A debit entry equal to incentives paid to customers; (N)

(Continued)

ELECTRIC PRELIMINARY STATEMENT PART EC
DEMAND RESPONSE EXPENDITURES BALANCING ACCOUNT

Sheet 3

3) A debit or credit entry to transfer amounts in this account to other accounts, or amounts from other accounts to this account upon approval by the Commission; and (N)

4) A debit entry equal to the interest on the average of the balance at the beginning of the month and the balance after the above entries at a rate equal to one-twelfth the interest rate on three-month commercial paper for the previous month, as reported in the Federal Reserve Statistical Release, H.15 or its successors. (N)

(D)

ELECTRIC SCHEDULE E-BIP
BASE INTERRUPTIBLE PROGRAM

APPLICABILITY: This schedule is available until modified or terminated in the rate design phase of the next general rate case or in another proceeding. The E-BIP Program (Program) is intended to provide load reductions on PG&E's system on a day-of basis when the California Independent System Operator (CAISO) issues a curtailment notice. Customers enrolled in the Program will be required to reduce their load down to their firm service level (FSL). This program may be closed by PG&E without notice when the interruptible program limits set forth in CPUC Decision 01-04-006 and Rulemaking 00-10-002 have been fully subscribed.

In accordance with CPUC Decision 09-08-027, service under this schedule is currently capped at 392 MW, which is the enrolled megawatt level on August 20, 2009. Customers may request to be placed on a waiting list to be served under this schedule subject to availability under the cap (N)

TERRITORY: This schedule is available throughout PG&E's electric service area.

ELIGIBILITY: This schedule is available to bundled-service, Community Choice Aggregation Service (CCA Service), and Direct Access (DA) commercial, industrial, and agricultural customers. Each customer, both directly enrolled and those in an aggregator's portfolio, must take service under the provisions of a demand time-of-use rate schedule to participate in the Program and have at least an average monthly demand of 100 kilowatt (kW). Customers being served under Schedules AG-R or AG-V are not eligible for this program. Customers taking service under Direct Access must meet the metering requirements prescribed in the Metering Equipment section of this rate schedule.

A customer may enroll directly with PG&E or with an aggregator. An aggregator is an entity, appointed by a customer, to act on behalf of said customer with respect to all aspects of the Program, including but not limited to: (1) the receipt of notices from PG&E under this program; (2) the receipt of incentive payments from PG&E; and (3) the payment of penalties to PG&E.

Each customer, both directly enrolled and those in an aggregator's portfolio, must designate the number of kW ("firm service level") to which it will reduce its load down to or below during a Program operation. The FSL must be no more than eighty-five percent (85%) of each customer's highest monthly maximum demand during the summer on–peak and winter partial-peak periods over the past 12 months with a minimum load reduction of 100 kW. If load information is unavailable, customers must demonstrate to PG&E's satisfaction that they can meet these minimum requirements.

Customers on this program may not have, or obtain, any insurance for the purpose of paying non-compliance penalties for willful failure to comply with requests for curtailments. Customers with such policy will be terminated from the Program, and will be required to pay back any incentives that the customer received for the period covered by the insurance. If the period cannot be determined, the recovery shall be for the entire period the customer was on the program.

Customers who are deemed essential under the Electric Emergency Plan as adopted in Decision 01-04-006 and Rulemaking 00-10-002, must acknowledge that the customer is voluntarily electing to participate in this program for part or all of its load based on adequate backup generation or other means to interrupt load upon request by the respondent utility, while continuing to meet its essential needs. In addition, an essential customer may commit no more than 50% of its average peak load to interruptible programs.

(Continued)

ELECTRIC SCHEDULE E-CBP
CAPACITY BIDDING PROGRAM

APPLICABILITY: The Capacity Bidding Program (CBP) is a voluntary demand response program that offers customers incentives for reducing energy consumption when requested by PG&E. Schedule E-CBP is available to PG&E customers receiving bundled service, Community Choice Aggregation (CCA) service, or Direct Access (DA) service and being billed on a PG&E commercial, industrial, or agricultural electric rate schedule. An eligible customer must continue to take service under the provisions of its otherwise applicable schedule (OAS).

TERRITORY: This schedule is available throughout PG&E's electric service area.

ELIGIBILITY: A customer may participate in either the Day-Ahead or Day-Of option. A customer with multiple service agreements (SA) may nominate demand reductions from a single SA to either the Day-of option or Day-ahead option. A SA may not be nominated to both the Day-of and Day-ahead option during a single program month.

A customer cannot be on Schedule E-CBP and participate in any other demand response program except for E-OBMC. Customers that receive electric power from third parties (other (T)
than through direct access), customers billed via net-metering (NEM, NEMFC, NEMBIO,
etc.), and customers billed for standby service are not eligible for the CBP. Partial standby (T)
customers are eligible for CBP. (T)

A customer may only enroll in Schedule E-CBP through an Aggregator. An Aggregator is an (T)
entity, appointed by a customer, to act on behalf of said customer with respect to all aspects of the CBP, including but not limited to: (1) the receipt of notices from PG&E under this program; (2) the receipt of incentive payments from PG&E; and (3) the payment of penalties to PG&E.

Aggregators and customers participating in the CBP must comply with the terms of this schedule and associated agreements.

SUBSCRIPTION LIMIT: PG&E reserves the right to limit the subscription amount available to participate in the CBP, consistent with Commission guidelines.

OPTIONS AND PRODUCTS: The program season is May 1 through October 31.

The program days are Monday through Friday during the program season, excluding PG&E holidays. PG&E holidays during the program season are the dates on which the following holidays are legally observed: Memorial Day, Independence Day, and Labor Day.

The program hours are 11 a.m. to 7 p.m. on program days.

The following options and products are available:

Day-Ahead Options

Product	Minimum Duration per Event	Maximum Duration per Event	Maximum Event Hours Per Operating Month	Maximum Events Per Day
1-4 Hour	1 hour	4 hours	24	1
2-6 Hour	2 hours	6 hours	24	1
4-8 Hour	4 hours	8 hours	24	1

(Continued)

ELECTRIC SCHEDULE E-CBP
CAPACITY BIDDING PROGRAM

PRODUCTS (Cont'd.):

Day-Of Options

Product	Minimum Duration per Event	Maximum Duration per Event	Maximum Event Hours Per Operating Month	Maximum Events Per Day
1-4 Hour	1 hour	4 hours	24	1
2-6 Hour	2 hours	6 hours	24	1
4-8 Hour	24 hours	8 hours	24	1

AGGREGATOR'S PORTFOLIO: An Aggregator must submit a Notice to Add or Delete Customers Participating in the Capacity Bidding Program (Form 79-1075) to add a customer's Service Agreements (SAs) to add or delete a customer's SAs from its portfolio. PG&E will review and approve each SA before the SA can be included in an Aggregator's portfolio. Additions to the portfolio will be effective upon PG&E's approval date. Deletions from the portfolio will be effective at the end of the current calendar month in which this notice is received provided PG&E receives this notice at least 15 calendar days prior to the end of the current month. A SA can be included in only one portfolio at a time.

CUSTOMER SPECIFIC ENERGY BASELINE: To participate in this program, a customer must have a valid customer specific energy baseline (CSEB) at least 5 calendar days prior to the first day of the operating month. (T)

A CSEB will be valid for purposes of participation if there are at least ten (10) similar days of interval data available in PG&E's CBP Website.

Each Capacity Nomination will have its own CSEB based its associated aggregated group. The CSEB on any given day during the program is the sum total of each individual SA's baseline in the group. Each individual SA baseline is the average for each hour based on the immediate past ten (10) similar weekdays prior to an event with the option of a day-of adjustment. The load during each hour of the ten days will be averaged to calculate an hourly baseline for each hour. The past ten (10) similar days will include Monday through Friday, excluding PG&E holidays and event days prior to the event (including events of this program, or any other interruptible or curtailment programs enrolled by the customer, or days when a rotating outage was called). (T)

The day-of adjustment is the ratio of a) the average load of the first three of the four hours prior to the event to b) the average load of the corresponding hours from the past 10 similar weekdays, as discussed above. The day-of adjustment will be limited to +/- 20% of each individual SA baseline in the group, and will be based on the first three of the four hours prior to the start of the event. The day-of adjustment is applied by multiplying it by each hourly baseline value. Customers must elect or opt-in to receive this adjustment. The customer is responsible for determining the applicable baseline day-of adjustment amount at the time of an event. PG&E will only be responsible for determining the applicable baseline day-of adjustment following each event for the purpose of evaluating customer compliance. If more than one event (either within the same or across multiple programs) occurs on the same day, the day-of adjustment from the event with the earliest start time will be used for the individual SA's events that day requiring a day-of adjustment. (N)

(Continued)

ELECTRIC SCHEDULE E-CBP
CAPACITY BIDDING PROGRAM

CUSTOMER SPECIFIC ENERGY BASELINE: (Cont'd.)

(D)

The hourly load profile on any given day during the program is determined by summing the hour by hour interval data for each of the SAs in the aggregated group. (D)

CAPACITY NOMINATIONS:

Capacity Nominations must be submitted by Aggregators no later than 5 calendar days prior to the operating month. Capacity Nominations must specify for each SA both an Option (Day-Ahead or Day-Of) and a Product. All Capacity Nominations are fixed for their associated operating month. All operating months begin and end at the beginning and ending of its corresponding calendar month. (T)

(D)

An Aggregator can include only those SAs that are in its portfolio.

(D)

An Aggregator must nominate capacity in the following categories:

Option (Day-Ahead or Day-Of)

Product

Bundled/Direct Access

No later than 5 calendar days prior to the first day of the operating month, an Aggregator must specify the SAs from its portfolio that shall be included in the aggregated group associated with each Capacity Nomination. The characteristics of selected SAs must match the categories of its associated Capacity Nomination. These aggregated groups will be used to determine the CSEB and performance during the operating month. A SA can be included in only one aggregated group and only one CSEB for a given operating month.

RATES:

The payments under this rate schedule will be determined from the following components.

1. Capacity Price
2. Capacity Payment and Capacity Penalty
3. Energy Payment

(Continued)

ELECTRIC SCHEDULE E-CBP
CAPACITY BIDDING PROGRAM

Sheet 4

CAPACITY PRICE: Capacity Price by Month (T)

Aggregators in Day-Ahead Option

Product	May	June	July	August	September	October
1-4 Hour	$0.00/kW	$3.71/kW	$15.60/kW	$21.57/kW	$13.30/kW	$0.00/kW
2-6 Hour	$0.00/kW	$3.71/kW	$15.60/kW	$21.57/kW	$13.30/kW	$0.00/kW
4-8 Hour	$0.00/kW	$3.71/kW	$15.60/kW	$21.57/kW	$13.30/kW	$0.00/kW

(D)

Aggregators in Day-Of Option

Product	May	June	July	August	September	October
1-4 Hour	$0.00/kW	$4.27/kW	$17.94/kW	$24.81/kW	$15.30/kW	$0.00/kW
2-6 Hour	$0.00/kW	$4.27/kW	$17.94/kW	$24.81/kW	$15.30/kW	$0.00/kW
4-8 Hour	$0.00/kW	$4.27/kW	$17.94/kW	$24.81/kW	$15.30/kW	$0.00/kW

(D)

(Continued)

ELECTRIC SCHEDULE E-CBP
CAPACITY BIDDING PROGRAM

CAPACITY PAYMENT AND CAPACITY PENALTY:

All Capacity Payments will be determined separately for each Capacity Nomination submitted by Aggregators as specified above. (T)

If no CBP Events were called during the operating month, then the Capacity Payment for the operating month is equal to product of Nominated Capacity and Capacity Price for the applicable operating month.

If one or more CBP Events were called during the operating month, then the Capacity Payment for the operating month is the sum of the Adjusted Hourly Capacity Payments/Penalties for the operating month which are determined as follows:

1) The Hourly Delivered Capacity for the event hour is equal to the CSEB for the event hour minus the average demand during the event hour. The average demand is defined as the energy consumed during the event hour converted to demand measured in kilowatts. The Hourly Delivered Capacity cannot be greater than the Nominated Capacity or less than zero (0).

2) The Hourly Delivered Capacity Ratio for the event hour is Hourly Delivered Capacity divided by the Nominated Capacity.

3) The Unadjusted Hourly Capacity Payment equals the product of the Nominated Capacity for the operating month and the Capacity Price for the operating month divided by the number of event hours in the operating month.

(Continued)

ELECTRIC SCHEDULE E-CBP
CAPACITY BIDDING PROGRAM

ENERGY PAYMENT:

All Energy Payments will be determined separately for each Capacity Nomination.

If no CBP Events were called during the operating month, then the monthly Energy Payment is zero (0).

If one or more CBP Events were called during the operating month, then the monthly Energy Payment is obtained by summing the Hourly Energy Payments. The Hourly Energy Payments will be determined as follows:

Nominated Energy $_{HR}$ = Nominated Capacity $_{HR}$

Delivered Energy $_{HR}$ = lesser of Delivered Capacity $_{HR}$ or 1.5 * Nominated Energy $_{HR}$

If Delivered Energy $_{HR}$ >= Nominated Energy $_{HR}$
Energy Payment $_{HR}$ = Delivered Energy $_{HR}$ * Energy Price $_{HR}$

If Delivered Energy $_{HR}$ < Nominated Energy $_{HR}$
Energy Payment $_{HR}$ = Delivered Energy $_{HR}$ * Energy Price $_{HR}$ less (Nominated Energy $_{HR}$ - Delivered Energy $_{HR}$) * the higher of the ex-post energy price for the event hour or the Energy Price $_{HR}$

Where the Energy Price $_{HR}$ = 15,000 BTU/kWh * PG&E citygate midpoint gas price as published by Platts Gas Daily for the date of the CBP Event ($/BTU)

See section below for special conditions regarding DA and CCA service customers' energy payments. (T)

(D)

SPECIAL CONDITIONS FOR DIRECT ACCESS AND CCA SERVICE CUSTOMERS:

Aggregators must make the necessary arrangements with the ESP of its DA or CCA service customers before enrolling DA or CCA service customers in this program. (T)

PG&E will not provide energy payments to directly-enrolled DA or CCA service customers, or Aggregator on behalf of a DA or CCA service customer, for load reductions during CBP events ($0/kWh), due to the Scheduling Coordinator (SC) to SC trade and payment changes to the CBP program. Customers and Aggregators will still receive capacity payments from PG&E for DA or CCA customers' load as applicable under this Schedule. This provision does not prevent DA or CCA customers from entering into arrangements with their respective ESPs or CCAs to receive part or all of the energy benefits derived from the DA or CCA customers' load reductions during CBP events. PG&E will notify existing CBP participants and Aggregators of this recent SC to SC program change.

(Continued)

ELECTRIC SCHEDULE E-CBP
CAPACITY BIDDING PROGRAM

SPECIAL CONDITIONS FOR DIRECT ACCESS AND CCA SERVICE CUSTOMERS: (Cont'd.)

See Agreement For Aggregators Participating In The Capacity Bidding Program (Form 79-1076) for additional information. (T)

METERING AND COMMUNICATIONS EQUIPMENT:

Each customer must have an approved interval meter and approved meter communications equipment installed and operating prior to participating on this program in order to establish a valid CSEB. See Baseline section for additional details.

An approved interval meter is capable of recording usage in 15-minute intervals and being read remotely by PG&E and by PG&E's Program Coordinator. If the customer is receiving DA service, then a Meter Data Management Agent (MDMA) may also read the customer's meter on behalf of the customer's ESP.

For bundled service customers with a maximum demand of 200 kW or greater for three consecutive months in the past 12 billing months, PG&E will provide and install the metering and communication equipment at no cost to the customer if metering and communication equipment are required. For other bundled service customers, PG&E will, if required, provide and install the metering equipment at the customer's expense pursuant to Electric Rule 2, Special Facilities.

Installation of an approved interval meter and approved meter communications equipment for a DA customer is the responsibility of the customer's ESP or its MDMA. The meter and associated equipment must be installed in accordance with Electric Rule 22. If PG&E is the MDMA on behalf of the DA customer's ESP, then no additional fees will be required. If the DA customer uses a third-party MDMA, then the customer will be responsible for any and all costs associated with providing PG&E acceptable interval data on a daily basis, including any additional metering or communication equipment and any additional fees assessed by the customer's ESP.

Prior to customer's participation in the program, the customer must be able to successfully transfer meter data according to PG&E's specification on a daily basis for a period of no less than ten (10) calendar days.

(D)

All measurements for the CSEB and performance will be determined using the customer's electric revenue interval meter without loss factor adjustments.

(Continued)

ELECTRIC SCHEDULE E-CBP
CAPACITY BIDDING PROGRAM

NOTIFICATION EQUIPMENT:	Aggregators, at their expense, must have: (1) access to the Internet and an e-mail address to receive notification of a CBP Event; and (2) an alphanumeric pager or cellular telephone that is capable of receiving a text message sent via the Internet, and/or a facsimile machine to receive notification messages. An Aggregator cannot participate in the CBP until all of these requirements have been satisfied.	(T) (T)
	If a CBP Event occurs, Aggregators will be notified using one or more of the above mentioned systems. It is the responsibility of the Aggregator to notify its aggregated customers.	(T)
	PG&E will make best efforts to notify Aggregators; however receipt of such notice is the responsibility of the Aggregator. In addition, the Aggregator may check PG&E's CBP website to see if a CBP Event has been triggered. PG&E does not guarantee the reliability of the pager system, e-mail system, or website by which the customer receives notification.	(T) (T) (D)
CONTRACTS AND FORMS:	Aggregators must submit a signed Agreement For Aggregators Participating In The Capacity Bidding Program (Form 79-1076). Aggregators must submit a Notice to Add or Delete Customers Participating in the Capacity Bidding Program (Form 79-1075) signed by the aggregated customer to add or delete a customer from its portfolio.	
CONTRACTUAL ARRANGEMENT BETWEEN CUSTOMER AND AGGREGATOR:	The terms and conditions of the agreement governing the relationship between the Aggregator and a customer with respect to such customer's participation in the CBP through such Aggregator are independent of PG&E. Any disputes arising between Aggregator and such customer shall be resolved by the parties.	
BILLING DISPUTES:	If an Aggregator disputes a bill issued by PG&E, the disputed amount will be deposited by the Aggregator with the California Public Utilities Commission (Commission) pending resolution of the dispute under the existing Commission procedures for resolving such disputes with PG&E. No termination of participation in the CBP will occur for this dispute while the Commission is hearing the matter, provided that the full amount in dispute is deposited with the Commission.	(T) (T)
	If a customer has a billing dispute with its Aggregator, the customer will remain obligated to pay PG&E charges for its OAS in a timely manner. Neither the Aggregator nor the customer shall withhold payment of PG&E charges pending resolution of a dispute between the customer and Aggregator.	

(Continued)

ELECTRIC SCHEDULE E-CBP
CAPACITY BIDDING PROGRAM

PROGRAM TRIGGER AND NOTIFICATION:

Day-Ahead Option:

PG&E may trigger a Day-Ahead CBP Event when PG&E's procurement stack is expected to require the dispatch of electric generation facilities with heat rates of 15,000 BTU/kWh or greater for the day-ahead market, or when PG&E, in its sole opinion, forecasts that resources may not be adequate. PG&E reserves the right not to call an event even when these thresholds are reached when PG&E, in its sole opinion, forecasts that resources may be adequate.

PG&E will notify Aggregators by 3:00 p.m. on a day-ahead basis of a CBP Event for the following business day. Notices will be issued by 3:00 p.m. on the business day immediately prior to a PG&E holiday or weekend if a CBP Event is planned for the first business day following the PG&E holiday or weekend. (T)

PG&E may call up to two (2) test Day-Ahead CBP Events per calendar year. Test CBP Events will be treated as actual CBP Events, including payments and penalties, and will count towards the product limits.

Day-Of Option:

PG&E may trigger a Day-Of Event when PG&E's procurement stack is expected to require the dispatch of electric generation facilities with heat rates of 15,000 BTU/kWh or greater for the hour-ahead market, or when PG&E, in its sole opinion, forecasts that resources may not be adequate. PG&E reserves the right not to call an event even when these thresholds are reached when PG&E, in its sole opinion, forecasts that resources may be adequate.

PG&E will notify Aggregators on a day-of basis, with up to approximately three hours notice prior to the start of a Day-Of Event. (T)

PG&E may call two (2) test Day-Of CBP Events per calendar year. Test Day-Of CBP Events will be treated as actual CBP Events, including payments and penalties, and will count towards the product limits.

PROGRAM RESEARCH AND ANALYSIS:

All customers participating on this program agree to allow personnel from the California Energy Commission (CEC), PG&E, and their contracting agents, reasonable access to conduct a site visit for measurement and evaluation, access to the customer's interval meter data, and agree to complete any surveys needed to enhance this program.

(Continued)

ELECTRIC SCHEDULE E-CBP
CAPACITY BIDDING PROGRAM

ACCESS TO CUSTOMER SPECIFIC USAGE DATA:	PG&E will provide an aggregated customer's electric usage and electric meter data for the Service Agreements to its Aggregator so Aggregator can determine the payment payable to and penalties chargeable to Customer under Schedule E-CBP.	
PROGRAM TERMS:	The initial term is 12 months. After the initial 12 months, an Aggregator may request to terminate its participation in this program by submitting to PG&E a completed Cancellation of Contract (Form 62-4778). The termination will be effective on the later of: (1) the beginning of the calendar month that is immediately after the initial 12 month term; and (2) the beginning of the calendar month that is closest to but at least thirty (30) calendar days after PG&E received the Cancellation of Contract. The Schedule E-CBP will remain available unless and until Schedule E-CBP is revised or terminated as directed by the CPUC.	(T)
	Customers may re-designate their election of a day-of adjustment to the baseline only once each year during the month of March. Customers shall provide written notification of such changes to PG&E. Changes will be effective on the subsequent May 1.	(N) I (N) (D)
PAYMENTS, AND AFFECT ON CUSTOMER'S BILL FOR THE OAS:	Payments due under this program will be sent as a check to the Aggregator within 60 calendar days after the end of the operating month. The charges under the OAS for an aggregated customer will not be adjusted.	(T)

ELECTRIC SCHEDULE E-CPP
CRITICAL PEAK PRICING PROGRAM

APPLICABILITY: The critical peak pricing (CPP) program is a voluntary alternative to traditional time-of-use rates. Schedule E-CPP is available to PG&E bundled-service customers with billed maximum demands of 200 kW or greater during any one of the past 12 billing months, and served on PG&E Demand Time-Of-Use (TOU) electric rate schedules A-10 TOU, E-19 (including E-19 voluntary), E-20, AG-4 (rates C and F only), AG-5 (rates C and F only) or their successors. Partial standby customers are also eligible to participate (T) in this program. Each customer must continue to take service under the provisions of (T) their otherwise-applicable schedule (OAS), and not be billed via net-metering. The CPP program only operates during the summer months (May 1 through October 31). This program will remain in place until superseded by a mandatory CPP rate schedule, which is expected in the Advanced Metering OIR, Rulemaking (R.) 02-06-001 or subsequent filings.

Customers may receive a transitional incentive to participate in the CPP program. Customers have the choice of receiving bill protection and subject to meeting qualification criteria (see Transitional Incentive Options section below).

Customers must have an interval meter and Internet access to PG&E's Inter-Act demand response operations website. Customers must have the required metering and notification equipment in place prior to participation in the CPP program.

TERRITORY: This schedule is available throughout PG&E's electric service area.

RATES: The customer will be billed for all regular charges applicable under its otherwise-applicable rate schedule. Additional charges (based on usage on CPP operating days) and credits (based on usage on non-CPP days) will be determined according to the rates specified in this tariff. See "Definition of Time Periods" section below for specific CPP TOU period definitions. The CPP periods may differ from those of the customer's OAS. The additional energy charges applicable on CPP operating days will be determined as follows:

CPP High-Price Period Usage: The total effective energy charge for usage during the CPP High-Price Period will be five (5) times the customer's summer on-peak energy rate under their otherwise-applicable rate schedule multiplied by the actual energy usage, plus

CPP Moderate-Price Period Usage: The total effective energy charge for usage during the CPP Moderate-Price Period will be three (3) times the customer's summer part-peak energy rate under their otherwise-applicable rate schedule multiplied by the actual energy usage.

Customers taking service under Schedule E-CPP will pay reduced total effective TOU energy rates, through offsetting summer on-peak and part-peak rate credits for usage on those days that are not declared as CPP operating days, as shown in the following table. Schedule E-CPP charges and credits will only be applicable during the Summer season (May 1 to October 31), and will not affect winter season rates or bills.

(Continued)

ELECTRIC SCHEDULE E-CPP
CRITICAL PEAK PRICING PROGRAM

PROGRAM RESEARCH AND ANALYSIS: Customers receiving service under this tariff must agree to allow personnel from the California Energy Commission (CEC), or its contracting agent, to conduct a site visit for measurement and evaluation, access to customer's interval meter data, and agree to complete any surveys needed to enhance the program. .

PROGRAM TERMS: The CPP program will remain open until terminated or superseded by action of the CPUC.

Customer's participation in this tariff will be in accordance with Electric Rule 12. Customers may terminate their E-CPP participation by providing a minimum of 30 days' written notice. Cancellation will become effective with the first regular billing cycle after the 30-day notice period. PG&E reserves the right to terminate the customer's E-CPP participation upon thirty (30) days written notice. .

BILLING: Monthly bills are calculated in accordance with the customer's OAS and the rates contained herein. The difference between the amount due under the customer's OAS and the amount due under critical peak pricing will appear on the customer's bill as an additional charge or credit.

CUSTOMER MULTIPLE-METER PREMISES: A customer with multiple service agreements on a single site (e.g., contiguous property, campus facilities, business parks) may participate in the CPP program with service agreements on the premises that are less than 200 kW (as described in the Applicability Section) provided at least one of the customer service agreements has a billed maximum demand of 200 kW or greater during any one of the past 12 billing months and is participating in the CPP program. The customer's taxpayer identification number must be the same for each service agreement participating in the CPP program under this provision. All other CPP program requirements must be met for each participating service agreement. The bill for each service agreement will be calculated on a stand-alone basis. .

TRANSITIONAL INCENTIVE OPTION: Bill Protection: A customer electing the bill protection transition incentive option will not pay more under the CPP program than it would pay under its otherwise-applicable rate schedule for the initial 12-month bill protection period provided the customer:
(1) remains in the CPP program for the entire duration of the rate protection period; and
(2) maintains an open service agreement. Bill protection benefits will be computed on a cumulative basis at the end of the bill protection period. Bill protection is capped at a maximum systemwide participation level of 200 MW of load drop. .

TECHNICAL ASSISTANCE AND TECHNOLOGY INCENTIVES: Technical assistance and technology incentives may be available to enhance the customer's ability to curtailment requests for on-peak demand reductions. (T)

(D)

(Continued)

ELECTRIC SCHEDULE E-DBP
DEMAND BIDDING PROGRAM

DEMAND RESPONSE OPERATIONS WEBSITE: (Cont'd)

PG&E's demand response operations website will be used to communicate all E-DBP events to the Customer. The event will be communicated to the customer by e-mail and/or e-page. Customer will then have the obligation to log-in to PG&E's demand response operations website in a timely manner to receive the specific details of the event and for customer action.

E-DBP EVENT NOTICE AND TRIGGER:

DAY-AHEAD NOTIFICATION

PG&E may issue a day-ahead E-DBP Event notification by 12:00 Noon when the California Independent System Operation (CAISO)'s day-ahead load forecast exceeds 43,000 MW or when the CAISO issues an Alert Notice, or when PG&E, in its sole opinion, forecasts that resources may not be adequate. PG&E reserves the right not to call an event when these thresholds are reached when PG&E, in its sole opinion, forecasts that resources will be adequate.

An E-DBP Event will only be called Monday through Friday between the hours of 12:00 Noon and 8:00 p.m., excluding PG&E holidays.

PG&E will notify customers by 12:00 Noon on a day-ahead basis when an E-DBP Event will occur the next business day. Notices will be issued by 12:00 Noon on the business day immediately prior to a PG&E holiday or weekend if an E-DBP Event is planned for the first business day following the PG&E holiday or weekend.

Customers shall submit bids to the program's website between 12:00 noon and 3:00 p.m. on the day the E-DBP Event notice was issued. After 4:00 p.m. on the day the E-DBP Event notice was issued, customers will receive confirmation of bid acceptance or rejection on the website. Unless a specific megawatt (MW) limit is requested, PG&E will accept all bids. In the event bids are restricted PG&E will accept bids on a first-come, first-served basis. If the customer's bid is accepted for a particular service agreement, then incentives payments will be determined separately for each service agreement and as specified in the Incentive Payments section. Once a customer's bid has been accepted, that bid shall not subsequently be rejected by the utility, but payment shall continue to be based on the customer's actual performance.

DAY OF NOTIFICATION

When the CAISO issues an alert during the day reflecting stress on the system (for example, a Warning Stage or greater), PG&E may implement an E-DBP Event for that same day. PG&E reserves the right not to call an event when these thresholds are reached when PG&E, in its sole opinion, forecasts that resources will be adequate.

An E-DBP Event will only be called Monday through Friday between the hours of 12:00 Noon and 8:00 p.m., excluding PG&E holidays.

(L)

(Continued)

ELECTRIC SCHEDULE E-DBP
DEMAND BIDDING PROGRAM

E-DBP EVENT NOTICE AND TRIGGER: (Cont'd.)

DAY OF NOTIFICATION (Cont'd.)

Once a Day-Of DBP Event has been issued, customers will have one hour to submit bids to the program's website. Unless a specific megawatt (MW) limit is requested, PG&E will accept all bids. Customers will receive confirmation of bid acceptance or rejection on the website within 15 minutes of the time the bidding window has closed. In the event bids are restricted PG&E will accept bids on a first-come, first-served basis. If the customer's bid is accepted for a particular service agreement, then incentives payments will be determined separately for each service agreement and as specified in the Incentive Payments section. Once a customer's bid has been accepted, that bid shall not subsequently be rejected by the utility, but payment shall continue to be based on the customer's actual performance. (L)

All E-DBP customers will receive the Day-Of DBP Event notice and are eligible to submit a bid for a Day-Of DBP Event.

If a Day-Of DBP Event is called on a day that a Day-Ahead DBP Event is scheduled or in progress, then those customers that have an accepted Day-Ahead bid for that day's DBP event may 1) increase its bids for those hours that the Day-Ahead and Day-Of DBP Events coincide, and 2) submit new bids for those hours in the Day-Of DBP Event that were not part of the Day-Ahead DBP event. If such a customer does not increase its existing bids, then its existing bids from the Day-Ahead DBP Event will be transferred to the Day-Of DBP Event for those hours that the Day-Ahead and Day-Of DBP Events coincide. Day-Ahead customer bids that are transferred to Day-Of will be paid at the Day-Of incentive level.

ENERGY BID:

E-DBP bidding shall be accepted for non-PG&E holiday weekdays only. The E-DBP Bid shall indicate the amount of kW curtailment that the participant is offering for each hour of the E-DBP Event. The participant may submit only one bid for each E-DBP Notification. Each bid must be for a minimum of two (2) hours and must be for consecutive hours during the E-DBP Event. The customer's bid must meet the minimum energy reduction threshold of 50 kW for each hour in the E-DBP Event. The participant must submit their bid within the timeframe specified in the E-DBP Event notice.

Each E-DBP bid submitted via the demand response operations website shall be for an E-DBP Event that can take place on the same day, the next eligible day, any weekday, excluding PG&E holidays, following the bid submission. Notification of E-DBP Bid acceptances will be posted to PG&E's website. Posting of accepted bids may be delayed due to unforeseen problems in transmitting or receiving the bids. PG&E cannot guarantee the reliability of the Internet site by which customers submit bids. PG&E may use and accept alternate means of notification as necessary. PG&E will communicate the following information on the website regarding accepted E-DBP Bids:

1. The Date and the Time Period of the E-DBP Events; and

(L)

(Continued)

ELECTRIC SCHEDULE E-DBP
DEMAND BIDDING PROGRAM

(L)

ENERGY BID: (Cont'd.)

2. The Customer Baseline (CB) on any given day during the program is the average for each hour based on the immediate past ten (10) similar weekdays prior to an event with the option of a day-of adjustment. The load during each hour of the ten days will be averaged to calculate an hourly baseline for each hour. The past ten (10) similar days will include Monday through Friday, excluding PG&E holidays and event days prior to the event (including events of this program, or any other interruptible or curtailment programs enrolled in by the customer, or days when a rotating outage was called). (T)

   The day-of adjustment is the ratio of a) the average load of the first three of the four hours prior to the event to b) the average load of the corresponding hours from the past 10 similar weekdays, as discussed above. The day-of adjustment to the CB will be limited to +/- 20%, and will be based on the first three of the four hours prior to the start of the event. The day-of adjustment is applied by multiplying it by each hourly baseline value. Customers must elect or opt-in to receive this adjustment. The customer is responsible for determining the applicable baseline day-of adjustment amount at the time of an event. PG&E will only be responsible for determining the applicable baseline day-of adjustment following each event for the purpose of evaluating customer compliance. If more than one event (either within the same or across multiple programs) occurs on the same day, the day-of adjustment from the event with the earliest start time will be used for the events that day requiring a day-of adjustment. (N)

3. The hourly pricing incentive that PG&E intends to offer for qualifying load reductions.

PROGRAM TESTING: PG&E may activate an E-DBP Day-Ahead or Day-Of Event with a simulated emergency event test trigger twice per year. Each emergency test event shall be no longer than four (4) hours. During such a test, the customer shall be responsible for curtailing load consistent with the terms of this schedule. Participants will receive incentive payment of $0.50/kW for qualifying load reduction during each hour of an E-DBP test event.

INCENTIVE PAYMENTS: PG&E will evaluate and pay for the customer's hourly load reductions realized under the Program within ninety (90) days after each E-DBP Event, depending on where the E-DBP Event falls within the participant's actual billing cycle. The incentive payments will be reflected in the customer's regular monthly bill as an adjustment.

BIDS SUBMITTED UNDER THE DAY-AHEAD NOTIFICATION

If the customer submitted a bid under the Day Ahead Notification, energy reduction for an E-DBP Event hour will be determined as the difference between the customer specific energy baseline (CSEB) for that hour and the customer's actual energy usage during that hour. Participants will be paid for load reductions up to a maximum of 150 percent (150%) of their accepted Day-Ahead bid (kW) on an hourly basis. Participants must drop at least 50 percent (50%) of their bid to qualify for any payment in any hour. In no case will a customer receive a credit payment for a given hour if it does not meet, in that hour of the event, the minimum energy reduction of 50 kW. The Day-Ahead E-DBP

(L)

(Continued)

ELECTRIC SCHEDULE E-DBP
DEMAND BIDDING PROGRAM

INCENTIVE PAYMENTS: (Cont'd.)

BIDS SUBMITTED UNDER THE DAY-AHEAD NOTIFICATION (Cont'd.) (L)

event incentives will be calculated on an hourly basis, and will be equal to the product of the qualified kW energy reduction for each hour a bid was accepted and the incentive price of $0.50/kWh.

BIDS SUBMITTED UNDER THE DAY-OF NOTIFICATION

If the customer submitted a bid under the Day Of Notification, energy reduction for an E-DBP Event hour will be determined as the difference between the customer specific energy baseline (CSEB) for that hour and the customer's actual energy usage during that hour. Participants will be paid for load reductions up to a maximum of 150 percent (150%) of their accepted Day-Of bid (kW) on an hourly basis. Participants must drop at least 50 percent (50%) of their bid to qualify for any payment in any hour. In no case will a customer receive a credit payment for a given hour if it does not meet, in that hour of the event, the minimum energy reduction of 50 kW.

The Day-Of E-DBP event incentives will be calculated on an hourly basis, and will be equal to the product of the qualified kW energy reduction for each hour a bid was accepted and the incentive price of $0.60/kWh.

BIDS SUBMITTED UNDER DAY-AHEAD NOTIFICATION PRIOR TO DAY-OF NOTIFICATION BEING ISSUED

If a participant is already participating in a Day-Ahead DBP event and a Day-Of Notification is issued, the participant's Day-Ahead bids will be transferred to the Day-Of DBP Event for those hours that the Day-Ahead and Day-Of DBP Events coincide, and the participant will be paid for load reductions up to a maximum of 200 percent (200%) of their accepted Day-Ahead bid (kW) on an hourly basis. Participants must drop at least 50 percent (50%) of their bid to qualify for any payment in any hour. In no case will a customer receive a credit payment for a given hour if it does not meet, in that hour of the event, the minimum energy reduction of 50 kW.

The participant will receive E-DBP event incentives based on the Day-Of event, that is calculated on an hourly basis, and is equal to the product of the qualified kW energy reduction for each hour a bid was accepted and the incentive price of $0.60/kWh.

AGGREGATED GROUP:

Customers that have multiple service agreements throughout the PG&E electric service territory are eligible for the aggregated group provisions of the program. The following conditions under the aggregate group option of this program supersedes the individual participation conditions where applicable:

1. Each individual service agreement must currently take service on an applicable PG&E rate schedule and have an installed interval meter as stated in the Applicability Section of this schedule. If necessary, a service agreement may change rate schedule and PG&E will provide and install an interval meter at no additional cost for each individual bundled service or CCA Service agreement

(L)

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ELECTRIC SCHEDULE E-DBP
DEMAND BIDDING PROGRAM

AGGREGATED GROUP: (Cont'd)

participating under the provisions of an aggregated group whose maximum demand is greater than or equal to fifty (50) kW during any one of the past twelve (12) billing months, provided that the service agreement remains on the program for a minimum of 12 months. Service agreements with an average demand that is less than fifty (50) kW must pay for the required communicating Interval Meter prior to participation. The installation of interval meters for a Direct Access customer is the responsibility of their Energy Service Provider or their agent. Fees associated with a rate change will be the responsibility of the customer. (L)

2. The customer must have at least one service agreement with a maximum demand of 200 kW or greater for at least one or more of the past 12 billing months within each aggregated group that will be designated as the primary service agreement for the aggregated group. The primary service agreement will oversee all activities of the group, including event notification and the receiving of the incentive payment. It is up to the lead service agreement to determine the dispersal of the credit to the other service agreements in the group.

3. All service agreements that are part of the aggregated group must take service from PG&E under the same federal tax identification number and be listed on the Demand Response Program Application. Individual service agreements, (excluding the lead service agreement), with less than 200 kW (as described in the Applicability Section) may participate in the program as part of the aggregated group.

4. Service agreements that are participating as an aggregated group will be exempt from the individual minimum load reduction amount. Instead Service agreements in the aggregated group will have a Group Minimum Load requirement of 200 kW. The Group Minimum Load represents: (1) the group's aggregated coincidental minimum load to qualify for the program; (2) the minimum bid amount that the aggregated group can submit for an E-DBP event; and (3) the group's minimum threshold that they must achieve to earn an incentive during an E-DBP event.

5. Energy reduction during an E-DBP event will be based on performance of all service agreements within the aggregated group and will be calculated as follows:

(L)

(Continued)

ELECTRIC SCHEDULE E-DBP
DEMAND BIDDING PROGRAM

(L)

AGGREGATED GROUP: (Cont'd)

a. The Group's Energy Baseline (GEB) is used to determine the aggregated group's average energy usage prior to an E-DBP event. The GEB is on any given day during the program is the sum total of each individual SA's baseline in the group. Each individual SA baseline is the average for each hour based on the immediate past ten (10) similar weekdays prior to an event with the option of a day-of adjustment. The load during each hour of the ten days will be averaged to calculate an hourly baseline for each hour. The past ten (10) similar days will include Monday through Friday, excluding PG&E holidays and event days prior to the event (including events of this program, or any other interruptible or curtailment programs enrolled in by the customer, or days when a rotating outage was called). (T)

The day-of adjustment is the ratio of a) the average load of the first three of the four hours prior to the event to b) the average load of the corresponding hours from the past 10 similar weekdays, as discussed above. The day-of adjustment will be limited to +/- 20% of each individual SA baseline in the group, and will be based on the first three of the four hours prior to the start of the event. The day-of adjustment is applied by multiplying it by each hourly baseline value. Customers must elect or opt-in to receive this adjustment. The customer is responsible for determining the applicable baseline day-of adjustment amount at the time of an event. PG&E will only be responsible for determining the applicable baseline day-of adjustment following each event for the purpose of evaluating customer compliance. If more that one event (either within the same or across multiple programs) occurs on the same day, the day-of adjustment from the event with the earliest start time will be used for the individual SA's events that day requiring a day-of adjustment.

b. The Group's energy usage during an E-DBP event is the total coincidental load of all the service agreements in the group measured during each hour of the event.

c. Energy reduction during an E-DBP event will be calculated as the difference between the GEB and the group's actual total usages during each hour of the event.

6. Modifications to the service agreement listing of an aggregated group may only occur during the March contract review period. During the contract review period customers may submit a written request to PG&E requesting additions or removal of service agreements within the aggregated group. Changes to the aggregated group will become effective after the customer's April billing cycle.

7. If one or more of the service agreements on the aggregated group, other than the lead service agreement, terminates service with PG&E prior to the contract review period, the other service agreements in the group will be responsible to maintain the 200 KW Group's Minimum Load requirement of the program until the contract can be adjusted during the next contract review period.

(L)

(Continued)

ELECTRIC SCHEDULE E-DBP
DEMAND BIDDING PROGRAM

AGGREGATED GROUP: (Cont'd)

8. **San Francisco Pilot Program** – On a limited basis, PG&E will allow unrelated customers, (customers that do not have the same federal tax identification number), that are located within the same zip code within the City and County of San Francisco to participate in E-DBP as an aggregated group. The San Francisco Pilot Program is limited to two pilot groups. PG&E will use a third party aggregator to oversee all activities of the two groups, including event notification and the receiving of the incentive payment. It is up to the aggregator to determine the dispersal of the credit to the service agreements in the pilot groups. The aggregator may, at PG&E's sole discretion, designate a lead service agreement for the pilot group which does not meet the minimum demand requirement of 200 kW to be designated a lead service agreement, or is located outside of the pilot group's zip code. If necessary, PG&E will provide and install an interval meter regardless of the participant's demand, at no additional cost for each individual bundled service, CCA Service, or Direct Access service agreement participating under the provisions of the San Francisco Pilot Program. This metering provision will be limited to 25 meters participating in the pilot program. Except for the requirements of having the same tax identification number, having a lead service agreement within the Aggregated Group, and the metering requirements stated above, each pilot group must comply with all of the provisions of an Aggregated Group and the schedule herein. (L)

TECHNICAL ASSISTANCE AND TECHNOLOGY INCENTIVES:

Technical assistance and technology incentives may be available to enhance the customer's ability to respond to curtailment requests for on-peak demand reductions. (T)

(D)

FAILURE TO REDUCE LOAD:

Except as provided in the Incentive Payment section of this schedule, no additional monetary penalties will be assessed under this Program for a customer's failure to comply (reduce energy) during any or all hours of an E-DBP Event.

PROGRAM TERMS:

Customers' participation in this tariff will be in accordance with Electric Rule 12. Customers may terminate their E-DBP participation by giving a minimum of 30 days written notice. Cancellation will become effective with the first regular billing cycle after the 30-day notice period. PG&E may terminate a participant's E-DBP participation at any time after giving a thirty (30) day written notice to participants.

Customers may re-designate their election of a day-of adjustment to the baseline only once each year during the month of March. Customers shall provide written notification of such changes to PG&E. Changes will be effective on the subsequent May 1. (N) I (N)

(L)

(Continued)

ELECTRIC SCHEDULE E-DBP Sheet 10
DEMAND BIDDING PROGRAM

INTERACTION WITH CUSTOMER'S OTHER APPLICABLE PROGRAMS AND CHARGES:	Participating customers' regular electric service bills will continue to be calculated each month based on their actual recorded monthly demands and energy usage. Customers who participate in a third-party sponsored interruptible load program must immediately notify PG&E of such activity. Load can only be committed to one program for any given hour of a curtailment, and customers will be paid for performance under only one program for a given load reduction. In other words, should another demand response program be activated, while an E-DBP Event is in progress, those events will supersede an E-DBP Event, and no E-DBP incentive payments will be applied for those overlapping hours. E-DBP customers shall not participate in PG&E's Capacity Bidding Program (Schedule E-CBP), the California ISO's Participating Load Program (Supplemental and Ancillary Services), any PG&E sponsored non-tariff demand response program or any other pay for performance program. Customers enrolled in the Scheduled Load Reduction Program (Schedule E-SLRP) may participate in E-DBP during the days when the customer's load is not scheduled for curtailment under the E-SLRP program.	(L)
EMERGENCY STANDBY GENERATION:	Customers may achieve energy reductions by operating back-up or onsite generation. The customer will be solely responsible for meeting all environmental and other regulatory requirements for the operation of such generation.	
COMMUNITY CHOICE AGGREGATION SERVICE CUSTOMERS AND DIRECT ACCESS SERVICE CUSTOMERS	Customers participating in this program and receiving service under CCA Service/Direct Access must notify their Community Choice Aggregator (CCA)/Energy Service Provider that they are participating in this program and when they participate in a DBP event. The per event notification must include the amount of hourly bid for each accepted bid. PG&E reserves the right to require that the CCA/Direct Access Service customer's Scheduling Coordinator (SC) must submit a Scheduling Coordinator to Scheduling Coordinator (SC to SC) trade with the service electric utility. If PG&E imposes this requirement, then: (1) the SC to SC trade must be submitted in a timeframe that complies with the California Independent System Operator's (ISO's) requirements; and (2) the CCA Service/Direct Access customer is responsible for all additional costs incurred by the serving utility if the customer's SC fails to submit a SC to SC trade, or if the SC to SC trade is not accepted by the ISO because of an action or inaction of the customer's SC.	
PROGRAM RESEARCH AND ANALYSIS:	Customers receiving service under this tariff must agree to allow personnel from the California Energy Commission (CEC), or its contracting agent, to conduct a site visit for measurement and evaluation, access to customer's interval meter data, and agree to complete any surveys needed to enhance the program.	(L)

ELECTRIC SCHEDULE E-OBMC

Sheet 1

OPTIONAL BINDING MANDATORY CURTAILMENT PLAN

APPLICABILITY: An Optional Binding Mandatory Curtailment (OBMC) Plan may be an alternative to a rotating outage (RO) for certain customers. Under an OBMC Plan, PG&E may authorize a customer to reduce their demand to an agreed upon level in lieu of being included in PG&E's rotating outage (RO) block progression. This schedule is open to all PG&E customers who can meet the eligibility requirements. An eligible customer should submit its OBMC Plan to PG&E for review and acceptance. If the plan is approved by PG&E, PG&E will send such approval to the customer in writing. The written approval letter will specify the effective start date of the plan.

In accordance with CPUC Decision 09-08-027, service under this schedule is currently capped at 10.9 MW, which is the enrolled megawatt level on August 20, 2009. Customers may request to be placed on a waiting list to be served under this schedule subject to availability under the cap. (N)

PROGRAM OPERATIONS: PG&E shall require a customer to operate its OBMC Plan upon each and every notice from the California Independent System Operator (CAISO) that a firm load curtailment is required within the PG&E service territory. Additionally, PG&E reserves the right to require a customer to operate its OBMC Plan when PG&E or the ISO has initiated or is planning to initiate firm load curtailments in a local geographic area within the PG&E service territory. OBMC Plan curtailments shall be required concurrent with each and every firm load curtailment.

Upon notification from PG&E of an OBMC curtailment, OBMC customers must immediately commence implementation of the load curtailment measures contained in their load reduction plan. Upon notice from PG&E, OBMC customers are required to reduce their load such that the load on their circuit or dedicated substation is at or below the Maximum Load Level (MLL) corresponding to the percent load reduction communicated in the notice.

The MLLs correspond to a reduction in a circuit's loading of between five (5) and fifteen (15) percent in five (5) percent increments. The CAISO may call for load reductions on a required MW level, but PG&E will require the OBMC customers to reduce their load to the next highest five (5) percent increment. For each operation, PG&E will notify the customer of the required percent reduction, along with the start and end times for the OBMC operation. PG&E may extend the end time or increase the percentage reduction of any ongoing OBMC operation as necessary to correspond with CAISO directives.

Maximum Load Levels (MLLs) shall be established by PG&E for the circuit or dedicated substation, which correspond to each of the 5, 10, and 15 percent load reduction levels. The following MLL calculation methodology shall apply for a) customers not participating in a capacity interruptible program, b) customers participating in a capacity interruptible program where the customer's baseline is less than the customer's capacity interruptible program firm service level (FSL), and c) customers participating in a capacity interruptible program where the customer has met their monthly or annual curtailment obligation. The MLL for the 5 percent load reduction is equal to the product of the baseline times 0.95. The MLL for the 10 percent load reduction is equal to the product of the baseline times 0.90. The MLL for the 15 percent load reduction is equal to the product of the baseline times 0.85.

(Continued)

ELECTRIC SCHEDULE E-OBMC
Sheet 2

OPTIONAL BINDING MANDATORY CURTAILMENT PLAN

PROGRAM OPERATIONS: (Cont'd.)

The following MLL calculation methodology shall apply for customers participating in a capacity interruptible program where the customer has not met their monthly or annual curtailment obligation and the customer's FSL under that program is less than the customer's baseline. The MLL for the 5 percent load reduction is equal to the product of the FSL times 0.95. The MLL for the 10 percent load reduction is equal to the product of the FSL times 0.90. The MLL for the 15 percent load reduction is equal to the product of the FSL times 0.85. Customers participating in a capacity interruptible program who complete their monthly or annual capacity interruptible program curtailment obligation during a concurrent OBMC curtailment must continue to curtail from the lower of the FSL or OBMC baseline until the conclusion of the OBMC curtailment.

The baseline for determining MLLs is equal to the average recorded hourly usage amount (if available) for the same hours as the OBMC operation hours on the immediate past ten (10) similar days, with the option of a day-of adjustment. Similar days exclude (T) those days when the customer was paid to reduce load under PG&E's Demand Bidding (T) Program and days when the OBMC program operated. For establishing similar days, if the OBMC event is called on a business day, then 10 prior business days are used; if the OBMC event is called on a weekend or holiday, then 10 prior weekend and holidays are used. The load measurements for the circuit shall be taken at PG&E's distribution substation.

(N) A customer electing the day-of baseline adjustment must make such election annually as part of the annual load reduction plan update and such election shall be binding for the subsequent twelve (12) months. The day-of adjustment is the ratio of a) the average load of the first three of the four hours prior to the event to b) the average load of the corresponding hours from the past 10 similar days, as discussed above. The day-of adjustment is applied by multiplying it by each hourly baseline value. The day-of adjustment will be limited to +/- 20%, and will be based on the first three of the four hours prior to the start of the event. The customer is responsible for determining the applicable baseline day-of adjustment amount at the time of an event. PG&E will only be responsible for determining the applicable baseline day-of adjustment following each event for the purpose of evaluating customer compliance. (N)

Each calendar year an OBMC participant may exclude the following periods from the 10-day baseline: (a) a period of 15 calendar days designated in advance both for ramp-up and ramp-down of operations during which period the baseline will be the hourly average circuit load for the most recent prior day; (b) up to 10 days as determined by the customer and designated in advance to accommodate conditions in the customer's operations that affect the 10-day baseline; and (c) up to two days as determined by the customer where unplanned outages or other events cause the circuit load to deviate substantially from normal conditions. The customer shall provide a minimum of 10 calendar days prior notice to PG&E when exercising option (a); a minimum of 7 calendar days prior notice to PG&E when exercising option (b); and notice to PG&E within one calendar day after the outage or event when exercising option (c). Customer requests for the above exclusions must be received by PG&E in written or email format within the specified time frames or the requested exclusion will not be allowed. Customers requesting an operation ramp-up period under option (a) above must also

(L)

(Continued)

ELECTRIC SCHEDULE E-OBMC Sheet 3
OPTIONAL BINDING MANDATORY CURTAILMENT PLAN

PROGRAM OPERATIONS: (Cont'd.)

specify a commensurate operation ramp-down period occurring within one year of the ramp-up period. The 10-day baseline following the ramp-down period must be reduced a minimum of 25% from the 10-day baseline immediately prior to the ramp-down period. Customers failing to achieve a 25% reduction in the 10-day baseline following a ramp-down period will not be allowed future operation ramp-up periods for two years following the ramp-up period. (L)

Required load reductions must be achieved as quickly as possible but no later than 15 minutes after the primary customer receives notification from PG&E. OBMC customers who fail to curtail to or below the required MLL of their circuit within the specific amount of time or who fail to maintain the MLL for the entire duration of the OBMC operation shall be subject to the non-compliance penalties specified below.

An OBMC Plan is not a guarantee against a customer being subject to a RO, because daily and emergency circuit switching may cause the circuit to become subject to ROs.

The customer may not receive advance notice from PG&E of such a RO. Additionally, an OBMC Plan is applicable to only electrical emergencies requiring a rotation outage, and it does not prevent a customer from being subject to outages caused by other load shedding schemes. All customers involved in a particular OBMC Plan must be served from the same circuit unless expressly agreed to by PG&E.

A single OBMC Plan shall be required for a group of customers on a particular circuit that are undertaking the load reductions. For a group of customers, one of the customers shall be the lead customer for the OBMC. This lead customer shall be the signing party of the OBMC Agreement and shall guarantee the load reductions and pay for all non-compliance penalties. This lead customer is responsible to work and coordinate with the other non-lead customers on its circuit. For a group of customers, the lead customer is representing the non-lead customers.

If requested by any one customer on a circuit, PG&E shall facilitate communication on establishing an OBMC Plan between all customers on the circuit.

OBMC customers with a single tax payer identification number may aggregate the load of two circuits for the purpose of participating in the OBMC program provided: (a) they are the lead customer for both circuits; (b) they have the ability to achieve required load reductions on the total load for the circuits; (c) they agree to achieve required load reductions on individual circuits subject to the aggregation as required by PG&E or the CAISO in response to geographic area constraints; and (d) the customer commits in the OBMC Agreement that it has not, and will not, receive any payment from any customer on any OBMC circuit for any action related to the OBMC program. All provisions of this schedule applicable to individual OBMC plans shall apply to the aggregated OBMC plan.

Customers are required to update their OBMC Plans by March 15 of each year, and confirm with PG&E any changes to the previous year's version and whether the (T)
customer is electing to the day-of baseline adjustment option. An OBMC Plan may (T)
become invalid over time because of circuit rearrangements or load additions, which make the MLL unachievable. Customers, therefore, are not guaranteed of being able to participate in this option from year to year.

(Continued)

ELECTRIC SCHEDULE E-PEAKCHOICE
PEAKCHOICE

APPLICABILITY: PeakChoice™ is a demand response program that offers customers flexibility and incentives to reduce demand when requested by PG&E.

TERRITORY: This schedule is available throughout PG&E's electric service territory.

ELIGIBILITY: PeakChoice is available to PG&E electric bundled service customers billed on a commercial, industrial, or agricultural demand-based time-of-use electric rate schedule subject to the limitations specified below.

A customer, or service agreement (SA), cannot be on Schedule E-PeakChoice and participate in any other demand response program except for E-OBMC or E-POBMC. An eligible customer must continue to take service under the provisions of its otherwise applicable schedule (OAS).

Customers billed via net-metering (NEM, NEMFC, NEMBIO, etc.), customers billed for standby service (Schedule S), and Schedules AG-V and AG-R are not eligible for (T) PeakChoice. Partial standby customers are eligible to participate in this program. In (T) addition, Medical Baseline customers are not eligible to participate in this program.

Each participating SA must reduce a minimum of ten (10) kilowatts (kW).

FLEXIBLE FEATURES AND OPTIONS: The program season is May 1 through October 31 (Summer Season). The program does not operate on PG&E holidays during the Summer Season, which are the days the following are legally observed: Memorial Day, Independence Day, and Labor Day.

There are two ways a customer may participate in this program: (1) Committed Load basis; and (2) Best Efforts basis. Customers electing to participate on a Committed Load basis may also elect to nominate additional load to participate on a Best Efforts basis. Committed Load customers electing to also participate on a Best Efforts basis must first meet their Committed Load obligations before qualifying for any Best Effort payments.

Committed Load – Committed Load customers receive a monthly capacity payment, in addition to an energy payment. Customers are required to curtail their load by the Committed Load amount relative to a baseline when notified of an event (see Customer Baseline section). Committed Load customers are subject to penalties for non-compliance during program events.

Best Effort – Best Effort customers receive incentives for performance and are paid based upon their level of energy reduction during an event. Best Effort customers are not subject to penalties for non-compliance.

Customers electing either basis for participation must designate specific program features to customize this program to meet their operational needs. The following features and options are available. A customer must elect one option from each feature below (Section A to F):

(Continued)

ELECTRIC SCHEDULE E-PEAKCHOICE
PEAKCHOICE

NON-DISCRETIONARY PROGRAM FEATURES:

1. The maximum number of event hours per Summer Season is 75 hours per customer. Customers may elect fewer event hours via their selection of event duration (Feature B) and number of events selected (Feature C).

2. A customer may not enroll more than 85% of its peak load in this program. Peak load is defined as the average of the three highest on-peak monthly billing demands during the most recent past six months of the current and/or previous Summer Season. PG&E reserves the right to review the customer's peak load and adjust the maximum allowable load drop commitment as needed.

3. Each customer may participate in only one event per day for load designated under its SA.

4. Customers must enroll in PeakChoice through PG&E's PeakChoice website.

5. PG&E will credit incentive payments and apply non-compliance penalties, where applicable, within a period no longer than ninety (90) days after each event. These payments and penalties will be reflected in the customer's bill as an adjustment.

6. Customers may change their selected options or unenroll in the program between November 1 and March 31, through PG&E's website.

7. Customers electing a two calendar day-ahead event notification time will be notified by 12 noon two days prior to the event. Customers electing one day-ahead event notification time will be notified by 2:00 p.m. one day prior to the event. (T)

8. A customer will not receive payments or owe penalties and will not be obligated to participate in any events until all necessary metering and communications equipment has been installed and all requirements have been met.

CUSTOMER BASELINE:

A Customer Baseline (CB) will be valid for purposes of participation if there are at least ten (10) similar weekdays of interval data available on PG&E's PeakChoice Website.

The CB on any given day during the program is the average for each hour based on the immediate past ten (10) similar weekdays prior to an event with the option of a day-of adjustment. The load during each hour of the ten days will be averaged to calculate an hourly baseline for each hour. The past ten (10) similar days will include Monday through Friday, excluding PG&E holidays and event days prior to the event (including events of this program, or any other interruptible or curtailment programs enrolled in by the customer, or days when a rotating outage was called). (T)

The day-of adjustment is the ratio of a) the average load of the first three of the four hours prior to the event to b) the average load of the corresponding hours from the past 10 similar weekdays, as discussed above. The day-of adjustment to the CB will be limited to +/- 20%, and will be based on the first three of the four hours prior to the start of the event. The day-of adjustment is applied by multiplying it by each hourly baseline value. Customers must elect or opt-in to receive this adjustment. The customer is responsible for determining the applicable baseline day-of adjustment amount at the time of an event. PG&E will only be responsible for determining the applicable baseline day-of adjustment following each event for the purpose of evaluating customer compliance. (N)
(L)

(Continued)

ELECTRIC SCHEDULE E-PEAKCHOICE
PEAKCHOICE

CUSTOMER BASELINE: (Cont'd.)

For events that begin on the half-hour, the CB will be the average of the hourly CB of those corresponding hours. For example, the CB for an event hour of 1:30 to 2:30, would be the average of the CB for 1:00 to 2:00 and 2:00 to 3:00. (L)

RATES:

The payments under this rate schedule will be determined depending on the customer's election of the type of commitment to reduce load and feature selections.

The prices below may be periodically changed with approval from the Commission.

Best Effort Rates and Payments

Customers that have elected to curtail load on a Best Effort basis will receive energy payments for PeakChoice events if they successfully confirmed and reduced at least 50% of their nominated Best Effort Load in any specific hour (BEL_{HR}). Customers will be paid up to a maximum of 150% of their nominated BEL_{HR}.

The Hourly Delivered Load ($Delivered\ Load_{HR}$) is equal to the Hourly Customer Baseline (CB_{HR}) minus the average demand during the event hour ($Actual\ Load_{HR}$). The average demand is defined as the energy consumed during the event hour converted to demand measured in kilowatts. The Hourly Delivered Load cannot be less than 10 kW.

The Best Effort Hourly Payments are determined as follows:

$$Delivered\ Load_{HR} = CB_{HR} - Actual\ Load_{HR}$$

$$50\%\ BEL_{HR} =< Deliverer\ Load_{HR} <= 150\%\ BEL_{HR}$$

$$Best\ Effort\ Payment_{HR} = Delivered\ Load_{HR} * Best\ Effort\ Rate_{HR}$$

Best Effort rates are based upon the amount of notification time elected before an event is called. Customers will be paid at the rate for the event they confirmed to participate in and successfully reduced load.

Event Notification Time	Best Effort $Rate_{HR}$
2 calendar days	$0.40/kWh
1 calendar day	$0.50/kWh
4.5 hours	$0.60/kWh
30 minutes	$1.00/kWh

(Continued)

ELECTRIC SCHEDULE E-SLRP

SCHEDULED LOAD REDUCTION PROGRAM

APPLICABILITY: This schedule is available until modified or terminated in the rate design phase of the next general rate case or as directed by the California Public Utilities Commission (CPUC). The Scheduled Load Reduction Program (Program) is intended to give customers the ability to provide load reductions on PG&E's system at pre-scheduled times. Participants must identify a specific four (4) hour time period(s), up to three times per week, that is coincident with the California Independent System Operator's (CAISO) system peak conditions as specified in the SLRP Option Section. During the summer season (June 1 through September 30), the customer commits to reduce their load, and load that is curtailed during an E-SLRP event may not be shifted to another time. Compliance to curtailment is mandatory under the Program and the customer must curtail during its selected SLRP option. This Program may be closed by PG&E without notice when the interruptible program limits set forth by the CPUC have been fully subscribed.

In accordance with CPUC Decision 09-08-027, service under this schedule is currently capped at 0 MW, which is the enrolled megawatt level on August 20, 2009. Customers may request to be placed on a waiting list to be served under this schedule subject to availability under the cap. (N)

TERRITORY: This schedule is available throughout PG&E's electric service area.

ELIGIBILITY: This schedule is available to PG&E's bundled-service customers on a first-come, first-served basis. Each customer must take service under the provisions of rate Schedules A-10, E-19 (including voluntary), or E-20, or their successors, to participate in the Program and have a minimum average monthly demand of 100 kilowatts (kW). Customers participating in the Program must commit to reduce load by at least fifteen percent (15%) of the customer baseline usage, with a minimum load reduction of 100 kW, as described in the Program Operations Section of this schedule.

Bundled-service customers whose commodity portion of their bill is otherwise calculated as the sum of the products of the customer-specific hourly load and the hourly commodity price are not eligible to take service under this schedule.

Participants must designate an SLRP option in which the customer will reduce their loads when requested (see Program Operation section for details) and the estimated minimum number of kW reduction ("Curtailment Reduction Amount") by which the customer will reduce its load during a Program operation. The Program is limited to a maximum total of 300 megawatts (MW) of estimated contracted Curtailment Reduction Amount for any given day, and 100 megawatts (MW) of estimated contracted Curtailment Reduction Amount for any given SLRP Option time period.

Customer's participation in the Program can only become effective after PG&E determines the customer has complied with all the terms and conditions of this schedule.

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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
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
Silo Energy LLC
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