EVALUATION OF 2005 STATEWIDE LARGE NONRESIDENTIAL DAY-AHEAD AND RELIABILITY DEMAND RESPONSE PROGRAMS

APPENDICES A-D

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and

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APPENDIX A
PROGRAM MATERIALS

A1. CPP Program Materials

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. Each customer must continue to take service under the provisions of their otherwise-applicable schedule (OAS). The CPP program only operates during the summer months (May 1 through October 31). Customers on this tariff must agree to allow the California Energy Commission (CEC) or its contracting agent to conduct a site visit for measurement and evaluation, and agree to complete any surveys needed to enhance the CPP program. This program will remain in place until superseded by a mandatory CPP rate schedule, which is expected in the Advanced Metering OIR, Rulemaking (R.) 02-06-001 or subsequent filings. (T)

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). (T) (T)

Customers must have an interval meter and Internet access to PG&E's Inter-Act, a web-based notification system. Customers must have the required metering and notification equipment in place prior to participation in the CPP program.

TERRITORY: This schedule is available to customers in PG&E's electric service territory.

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)

SCHEDULE E-CPP—CRITICAL PEAK PRICING PROGRAM
(Continued)

RATES: (Cont'd.)

Schedule E-CPP charges and credits vary according to the customer's OAS, and are as shown in the table below:

	Non-CPP Days (Credit) per kilowatt hour of usage		**CPP Days (Charge)** per kilowatt hour of usage	
	On-Peak	Part-Peak	Moderate-Price	High-Price
E-20T	$0.01372 (R)	$0.01025	$0.14661 (R)	$0.3374 (R)
E-20P	$0.00957 (I)	$0.02330 (I)	$0.15820 (I)	$0.50337 (I)
E-20S	$0.02389 (I)	$0.01367 (I)	$0.15974 (I)	$0.53386 (I)
E-19T	$0.02199 (R)	$0.00635	$0.17875 (R)	$0.41228 (R)
E-19P	$0.02925 (I)	$0.00822 (I)	$0.16864 (I)	$0.53215 (I)
E-19S	$0.03258 (I)	$0.00873 (I)	$0.17062 (I)	$0.56681 (I)
A-10T	$0.03495	$0.02442	$0.11927 (R)	$0.93414 (I)
A-10P	$0.03011 (I)	$0.01169	$0.26301 (I)	$0.58631 (I)
A-10S	$0.03777 (I)	$0.01144	$0.25987 (I)	$0.58665 (I)
AG-4C, F	$0.01956 (I)	$0.01860 (I)	$0.15967 (I)	$0.57828 (I)
AG-5C, F	$0.01980 (I)	$0.00921 (I)	$0.12168 (I)	$0.42794 (I)

Please refer to the sections of this tariff labeled "Program Operations" and "Notification and Trigger" for a complete description of how CPP Operating Days will be determined, and how customers will be notified of those days when CPP Operating Day prices will be in effect.

(Continued)

SCHEDULE E-CPP—CRITICAL PEAK PRICING PROGRAM
(Continued)

DEFINITION OF TIME PERIODS:

SUMMER (service from May 1 through October 31): (N)

CPP Operating Days (Monday through Friday, except holidays)

CPP High-Price:	3:00 p.m. to 6:00 p.m.
CPP Moderate-Price:	12:00 noon to 3:00 p.m.

Non-CPP Operating Days

Peak:	As defined in the customer's otherwise-applicable rate schedule.
Partial-Peak:	As defined in the customer's otherwise-applicable rate schedule.
Off-Peak:	As defined in the customer's otherwise-applicable rate schedule.

WINTER (service from November 1 through April 30)

Partial-Peak:	As defined in the customer's otherwise-applicable rate schedule.
Off-Peak:	As defined in the customer's otherwise-applicable rate schedule.

Please refer to the sections of this tariff labeled "Program Operations" and "Notification and Trigger" for a complete description of how CPP Operating Days will be determined, and how customers will be notified of those days when CPP Operating Day prices will be in effect. (N)

(Continued)

SCHEDULE E-CPP—CRITICAL PEAK PRICING PROGRAM
(Continued)

DEFINITION OF TIME PERIODS: (Cont'd.)	HOLIDAYS: The CPP program will not operate on holidays. "Holidays" are Memorial Day, Independence Day, and Labor Day. The dates will be those on which the holidays are legally observed.	
METERING EQUIPMENT:	Each participating customer account must have an interval meter installed that can be remotely read by PG&E. Metering equipment (including telephone line, cellular, or radio communication device) must be in operation for at least ten (10) days prior to participating in the program to establish baseline. If required, as a provision for participating in the program, PG&E will provide and install the metering equipment and will also provide meter data retrieval at no cost to those customers receiving free meters through this tariff until otherwise directed by the CPUC.	(T) | (T) (D)
NOTIFICATION EQUIPMENT:	Customers, at their expense, must have access to the Internet and an e-mail address to receive notification of a CPP event. In addition, all customers must have, at their expense, an alphanumeric pager that is capable of receiving a text message sent via the Internet. A customer cannot participate in the CPP program until all of these requirements have been satisfied. If a CPP event occurs, customers will be notified using one or more of the above-mentioned systems. Receipt of such notice is the responsibility of the participating customer. PG&E will make best efforts to notify customers, however it is the customer's responsibility to receive such notice and to check the PG&E website to see if the Program is activated. PG&E does not guarantee the reliability of the pager system, e-mail system or Internet site by which the customer receives notification.	
CONTRACTS:	Customers must submit a signed Demand Response Program Agreement (Form 79-976) and a Customer Agreement and Password Agreement Governing Use of Internet-Based Software (Form 79-977) in order to receive service. Customer's participation in this tariff will be in accordance with Electric Rule 12. Customers may terminate their E-CPP agreement by submitting a signed Cancellation of Contract and providing a minimum of 30 days' written notice. Cancellation of the agreement will become effective with the first regular billing cycle after the 30-day notice period. PG&E reserves the right to terminate the agreement upon thirty (30) days written notice.	(T) | (T)

(Continued)

SCHEDULE E-CPP—CRITICAL PEAK PRICING PROGRAM
(Continued)

PROGRAM OPERATIONS: PG&E will notify customers by 3:00 p.m. on a day-ahead basis when a CPP operation day will occur the next business day. A CPP event will only be called Monday through Friday, excluding holidays. Notices will be issued on Friday by 3:00 p.m. for events occurring on the following Monday, or for events that are issued for Tuesday following a holiday that falls on Monday. The trigger or activation of a CPP event will be the forecasted temperatures at designated specific locations in two geographical zones. Each specific zone will operate CPP events individually, meaning that a CPP event may be triggered in one or both zones. (T) (T)

NOTIFICATION AND TRIGGER: CPP operating days will ordinarily be determined based on day-ahead maximum temperature forecasts at specific locations within each of two designated PG&E zones. The two zones are Zone 1 (San Francisco and Peninsula) and Zone 2 (all other areas PG&E provides service).

Beginning May 1st of each summer season, the initial forecasted temperature thresholds for triggering CPP events will be:

Zone 1: 92 degrees (average of forecasts for San Francisco and San Jose) (T)

Zone 2: 96 degrees (average of forecasts for San Jose, Concord, Redding, Sacramento and Fresno) (T)

PG&E will adjust the forecasted temperature thresholds up or down, over the course of the summer as necessary, to achieve the CPP program design basis of 12 operating days each summer. Bi-monthly (1st and 15th), PG&E will review the number of CPP operating days that have already occurred and may adjust the applicable temperature threshold for each zone up or down (increments of 2 degrees), in accordance with historical weather patterns. Customers will be notified of the applicable temperature threshold for their zone via the Inter-Act system. (D)

CPP events may also be initiated as warranted by extreme system conditions such as special alerts issued by the California Independent System Operator, or under conditions of high forecasted California spot market power prices or for testing/evaluation purposes. PG&E may call up to four test CPP events per year. Test CPP events may be issued at PG&E's discretion when the day-ahead forecasted temperature is within five degrees of the current temperature trigger for the program. Test events will count as an actual event when evaluating the bi-monthly temperature adjustment. (N)
|
|
|
(N)

(Continued)

SCHEDULE E-CPP—CRITICAL PEAK PRICING PROGRAM
(Continued)

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, and agree to complete any surveys needed to enhance the CPP program. Customers must submit a signed Authorization To Receive Customer Information or Act On A Customer's Behalf form giving the CEC authorization to request billing history and meter usage data information. (T) (T)

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

BILLLING: 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. (T)

CUSTOMER MULTIPLE-METER PREMISES: A customer with multiple accounts on a single site (e.g., contiguous property, campus facilities, business parks) may participate in the CPP program with accounts on the premises that are less than 200 kW (as described in the Applicability Section) provided at least one of the customer accounts 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 account participating in the CPP program under this provision and each account must be listed on the Demand Response Program Agreement. All other CPP program requirements must be met for each participating account. The bill for each account 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: (T)
(1) remains in the CPP program for the entire duration of the rate protection period; and (2) maintains an open account. 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 AUDIT ASSISTANCE AND EQUIPMENT INCENTIVES: Technical audit assistance and equipment incentives are available to enhance the customer's ability to curtailment requests for on-peak demand reductions.

(Continued)

SCHEDULE E-CPP—CRITICAL PEAK PRICING PROGRAM
(Continued)

INTERACTION WITH OTHER DEMAND REDUCTION PROGRAMS:	Participants in the CPP program may also participate in the Demand Bidding Program (Schedule E-DBP) and the California Power Authority Demand Reserves Partnership Program (CPA DRP) but shall not receive energy payment for performance under those programs during CPP event hours. Customers who participate in a California Power Authority (CPA) or a third-party sponsored interruptible load program must immediately notify PG&E of such activity. CPP participants shall not participate in the Non-Firm Program, Base Interruptible Program (Schedule E-BIP), the Optional Binding Mandatory Curtailment Program (Schedule E-OBMC), the Pilot Optional Binding Mandatory Curtailment Program (Schedule E-POBMC), or the Scheduled Load Reduction Program (Schedule E-SLRP) while on the CPP program.	(N)

Pacific Gas and Electric Company®

Critical Peak Pricing

The Critical Peak Pricing (CPP) benefits you on weekdays in the summer season by reducing or shifting your energy usage away from the noon to 6 p.m. peak period during 12 or fewer CPP events. In exchange for this, you will receive a discount on all part and on-peak usage on all other days of the summer period that starts May 1 and ends October 31.

How It Works

CPP events will generally be triggered by temperature, but may also be activated by PG&E as warranted by extreme system conditions:

- Special alerts issued by the California Independent System Operator
- Under conditions of high forecasted California spot market power prices
- For testing /evaluation purposes

CPP participants will be notified through PG&E's InterAct II by 3 p.m. the business day before PG&E determines that a CPP event is to be called.

Usage during summer peak hours is discounted on days when no CPP events are called. For any kwh usage that occurs weekdays between noon and 6 p.m. on a designated CPP day there are higher "critical peak" on-peak energy charges. Within the critical peak period, there will be two higher priced time periods:

- Discount Price Period—All part and on-peak usage during summer period days when no CPP event is called
- Moderate Price Period—Noon to 3 p.m., when customers will be charged approximately three times their normal (otherwise applicable) rate schedule part-peak energy rate and
- High Price Period—3 p.m. to 6 p.m., when customers will be charged approximately five times their normal (otherwise applicable) rate schedule on-peak energy rate

Incentives

Participants in the CPP may elect to take advantage of incentive programs:

- The Bill Protection Incentive option provides the customer with 100 percent protection against paying energy rates greater than you pay now under your current program-eligible rate schedule for the first 12 consecutive months of program participation
- The Enhanced Automation Incentive Program offered by the California Energy Commission, may help the customer become more knowledgeable about your potential for reducing load during CPP event
- The Technical Assistance Incentive Program, offered by PG&E allows the customer to earn cash for professional technical assistance that enhances your ability to respond to curtailment requests for on-peak demand reductions.
- CPP participants may elect to receive one or all of these incentives.

Qualifying for E-CPP

You qualify for E-CPP if you meet all of the following requirements:

- Currently a Pacific Gas and Electric Company bundled service customer
- Served under PG&E Demand Time-Of-Use electric rate schedules A-10 TOU, E-19 (including E-19 Voluntary), E20, AG4 (option C&F), AG5 (option C&F)
- Have billed maximum demand of 200 kw or greater during any one of the past 12 billing months
- Not participating in Pacific Gas and Electric Company's Scheduled Load Reduction Program, Base Interruptible Program, Optional Binding Mandatory Program, and the Pilot Optional Binding Mandatory Program

Equipment Requirements

If required, PG&E will provide and install the metering equipment at no cost to the customer.

For more information about how your business can benefit from InterAct II and our demand response programs, contact your local PG&E Account Representative or call 1 (800) 468-4743.

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Schedule GS2-TOU-CPP Sheet 1

GENERAL SERVICE-TIME-OF-USE-DEMAND METERED
CRITICAL PEAK PRICING-VOLUMETRIC CHARGE DISCOUNT-VCD

APPLICABILITY

This Schedule is optional for Bundled Service Customers currently served under Schedule TOU-GS-2 or GS-2 with the Time-of-Use Pricing Option, with maximum demands above 200 kW, defined herein as registered Maximum Demand of greater than 200 kW in any three months during the preceding twelve months, but not exceeding 500 kW. A customer served under this Schedule whose monthly Maximum Demand, in the opinion of the SCE, is expected to exceed 500 kW or has exceeded 500 kW in any three months during the preceding 12 months is ineligible for service under this Schedule and shall be transferred to Schedule TOU-8-CPP. Further, any customer served under this Schedule whose monthly Maximum Demand has registered less than 200 kW for twelve consecutive months is also ineligible for service under this Schedule and shall be transferred to an applicable rate schedule. Customer service accounts served under Schedule S are not eligible for service under this Schedule. A customer's participation in other demand response programs may affect a customer's eligibility for service under this Schedule, or the level of credits available under such other programs (see Special Conditions section). Service under this Schedule requires the installation of interval metering equipment, as defined in this Schedule's Special Conditions section, prior to participation under this Schedule and is subject to the availability of such metering.

TERRITORY

Within the entire territory served.

RATES

	Delivery Service							Gen[8]	
	Trans[1]	Distrbtn[2]	NDC[3]	PPPC[4]	PUCRF[5]	DWRBC[6]	Total[7]	URG**	DWR
Energy Charge- $/kWh/Meter/Month									
CPP Event									
Summer Season									
CPP Moderate Price Period									
Noon – 3:00 p.m.	0.00157	0.00834 (I)	0.00048	0.00801 (I)	0.00012 (I)	0.00485	0.02337 (I)	0.49516	0.10369
CPP High-Price Period									
3:00 p.m. – 6:00 p.m.	0.00157	0.00834 (I)	0.00048	0.00801 (I)	0.00012 (I)	0.00485	0.02337 (I)	1.39307 (I)	0.10369
Non CPP Event Time Periods									
Summer Season – On Peak	0.00157	0.00834 (I)	0.00048	0.00801 (I)	0.00012 (I)	0.00485	0.02337 (I)	0.15038 (I)	0.10369
Mid Peak	0.00157	0.00834 (I)	0.00048	0.00801 (I)	0.00012 (I)	0.00485	0.02337 (I)	0.06163	0.10369
Off-Peak	0.00157	0.00834 (I)	0.00048	0.00801 (I)	0.00012 (I)	0.00485	0.02337 (I)	0.01765	0.10369
Winter Season – Mid-Peak	0.00157	0.00834 (I)	0.00048	0.00801 (I)	0.00012 (I)	0.00485	0.02337 (I)	0.09584	0.10369
Off-Peak	0.00157	0.00834 (I)	0.00048	0.00801 (I)	0.00012 (I)	0.00485	0.02337 (I)	0.02081	0.10369
Customer Charge - $/Meter/Month		64.54 (I)					64.54 (I)		
Demand Charge - $/kW of Billing Demand/Meter/Month									
Facilities Related	1.09	4.45 (I)					5.54 (I)	4.08	
Time Related									
Summer		6.93 (I)					6.93 (I)	9.93	
Winter		0.00					0.00	0.00	
Single Phase Service - $/Month		(3.03) (I)					(3.03) (I)		

(Continued)

Schedule GS2-TOU-CPP Sheet 2

GENERAL SERVICE-TIME-OF-USE-DEMAND METERED
CRITICAL PEAK PRICING-VOLUMETRIC CHARGE DISCOUNT-VCD
(Continued)

RATES (Continued)

	Delivery Service							Gen[8]	
	Trans[1]	Distrbtn[2]	NDC[3]	PPPC[4]	PUCRF[5]	DWRBC[6]	Total[7]	URG**	DWR
Voltage Discount, Demand - $/kW									
Facilities Related									
From 2 kV to 50 kV		(0.11)					(0.11)	(0.04)	
Above 50 kV		(3.72)					(3.72)	(0.10)	
Time Related									
From 2 kV to 50 kV		(0.18)					(0.18)	(0.10)	
Above 50 kV		(6.01)					(6.01)	(0.25) (R)	
Voltage Discount, Energy - $/kWh									
From 2 kV to 50 kV		0.00000					0.00000	(0.00131)(R)	
Above 50 kV		0.00000					0.00000	(0.00283)(R)	
Power Factor Adjustment - $/kVA									
Greater than 50 kV		0.17					0.17		
50 kV or less		0.19					0.19		
California Alternate Rates for Energy Discount - %		100.00					100.00*		

* Represents 100% of the discount percentage as shown in the applicable Special Condition of this Schedule.
** The ongoing Competition Transition Charge (CTC) of $0.01149 is recovered in the URG component of Generation.
1 Trans = Transmission and the Transmission Owners Tariff Charge Adjustments (TOTCA) which are FERC approved. The TOTCA represents the Transmission Revenue Balancing Account Adjustment (TRBAA) of negative $(0.00124) per kWh, Reliability Services Balancing Account Adjustment (RSBAA) of $0.00199 per kWh, and Transmission Access Charge Balancing Account Adjustment (TACBAA) of $0.00082 per kWh. (I)
2 Distrbtn = Distribution
3 NDC = Nuclear Decommissioning Charge
4 PPPC = Public Purpose Programs Charge (includes California Alternate Rates for Energy Surcharge where applicable.)
5 PUCRF = The PUC Reimbursement Fee is described in Schedule RF-E.
6 DWRBC = Department of Water Resources (DWR) Bond Charge. The DWR Bond Charge is not applicable to exempt Bundled Service and Direct Access Customers, as defined in and pursuant to D.02-10-063, D.02-02-051, and D.02-12-082.
7 Total = Total Delivery Service rates that are applicable to both Bundled Service, Direct Access (DA) and Community Choice Aggregation Service (CCA Service) customers, except DA and CCA Service customers are not subject to the DWRBC rate component of this Schedule but instead pay the DWRBC as provided by Schedule DA.
8 Gen = Generation – The Gen rates are applicable only to Bundled Service Customers. When calculating the Energy Charge, the Gen portion is calculated as described in the Billing Calculation Special Condition of this Schedule.

(Continued)

Schedule GS2-TOU-CPP Sheet 3
GENERAL SERVICE-TIME-OF-USE-DEMAND METERED
CRITICAL PEAK PRICING
(Continued)

SPECIAL CONDITIONS

1. Time periods are defined as follows:

CPP Moderate–Price Period: Noon to 3:00 p.m. during a CPP Event only

CPP High-Price Period: 3:00 p.m. to 6:00 p.m. during a CPP Event only

On-Peak: Noon to 6:00 p.m. summer weekdays except CPP Moderate-Price Periods, CPP High-Price Periods, and holidays
Mid-Peak: 8:00 a.m. to Noon and 6:00 p.m. to 11:00 p.m. summer weekdays except holidays
8:00 a.m. to 9:00 p.m. winter weekdays except holidays
Off-Peak: All other hours.

Holidays are New Year's Day (January 1), Washington's Birthday (third Monday in February), Memorial Day (last Monday in May), Independence Day (July 4), Labor Day (first Monday in September), Veterans Day (November 11), Thanksgiving Day (fourth Thursday in November), and Christmas (December 25).

When any holiday listed above falls on Sunday, the following Monday will be recognized as an off-peak period. No change will be made for holidays falling on Saturday.

The summer season shall commence at 12:00 a.m. on the first Sunday in June and continue until 12:00 a.m. of the first Sunday in October of each year. The winter season shall commence at 12:00 a.m. on the first Sunday in October of each year and continue until 12:00 a.m. of the first Sunday in June of the following year.

2. CPP Events: SCE may, at its discretion, invoke a CPP Event during the summer season time period of Noon to 6:00 p.m., when SCE determines any of the following conditions exist: there is high system peak demand and/or low generation reserves; system constraints; high wholesale market prices; a Los Angeles Civic Center temperature of 87 degrees or above by 2 p.m. the day prior to a CPP Event; special alerts issued by California Independent System Operator (CAISO); and/or for testing/evaluation purposes. SCE will adjust the temperature threshold up or down, on a bi-monthly basis, to achieve the CPP program design basis of 12 CPP Events per summer season. (T) (T) (D)

3. Number of CPP Events: CPP Events will be invoked by SCE during the summer season and shall be limited to 12 CPP Events, which includes up to four events for testing/evaluation purposes. (T) (T)

4. Notification of a CPP Event: SCE will notify customers of a CPP Event via SCE's notification system. SCE's primary notification method will be via telephone call, but the customer may also elect to receive notification via pager, electronic mail, cellular telephone, or by fax as a courtesy. SCE will begin to notify customers by 3:00 p.m. the day before a CPP Event. If SCE cannot contact the customer on the first attempt, at least two more attempts will be made. However, SCE does not guarantee customer receipt of the notification. Customers will be responsible for all charges incurred during a CPP Event, even if actual notice is not received. (T) (D)

(Continued)

Schedule GS2-TOU-CPP Sheet 4
GENERAL SERVICE-TIME-OF-USE-DEMAND METERED
CRITICAL PEAK PRICING-VOLUMETRIC CHARGE DISCOUNT-VCD
(Continued)

SPECIAL CONDITIONS (Continued)

5. Participation in other Programs: Customers served under this Schedule may also participate in SCE's Demand Bidding Program (DBP) or the California Power Authority Demand Reserves Partnership Program (CPA DRP), but will be ineligible for any energy credits under these programs during a CPP Event.

6. Required Metering and Notification Equipment: Prior to participation on this Schedule, a customer must have Interval Metering and a designated primary phone line capable of receiving CPP Event notifications. Metering equipment must be in operation for at least ten (10) weekdays (non holidays) prior to participation on this Schedule to establish a customer's Customer Specific Energy Baseline (CSEB). For participating service accounts without the required interval metering SCE will provide and install such equipment at no cost to the customer through December 31, 2004.

7. Transitional Incentive Option: A Bill Protection option is available to eligible customers served under this Schedule. Customers who do not, or can not, participate in the Bill Protection Option will be subject to the charges under this Schedule at all times. Customers who meet the conditions outlined below may participate in the following Transitional Incentive Option: (T)

   a. Bill Protection Option:

      (1) A participating customer may receive a Bill Protection credit for the difference in total charges, when such charges, as calculated under this Schedule, exceed total charges as calculated under the customer's Otherwise Applicable Tariff (OAT), as measured over a period of 12 months from the date the customer elects this option (Commitment Period). For purposes of this Special Condition, a customer's OAT shall be defined as the non-CPP rate schedule from which the customer transferred from, prior to participation on this rate schedule; (T)

      (2) This option will be closed to new customers on all CPP Schedules once SCE determines that 200 MWs of potential load reduction is participating on the Bill Protection Option. Additionally, this option is only available to customers who elect it within the first 30 days of receiving service on this schedule; (T)

      (3) If a participating customer is either voluntarily or involuntarily removed from this Schedule prior to completion of the Commitment Period, such customer shall not be eligible for any Bill Protection credits for the period such customer was served under this Schedule; (T)

      (4) At the end of the Commitment Period one of the following will occur:

         (a) If a participating customer's bill, as calculated under this Schedule over the entire Commitment Period is greater than their bill as calculated under their OAT over the entire Commitment Period, then such customer will receive a Bill Protection Credit equal to CPP charges minus OAT charges; (T)

         (b) If a participating customer's bill, as calculated under this Schedule over the entire Commitment Period is equal to or less than their bill as calculated under their OAT over the entire Commitment Period, then such customer will not receive a Bill Protection Credit.

(Continued)

Schedule GS2-TOU-CPP Sheet 5
GENERAL SERVICE-TIME-OF-USE-DEMAND METERED
CRITICAL PEAK PRICING
(Continued)

SPECIAL CONDITIONS (Continued)

7. Transitional Incentive Options: (Continued)

a. Bill Protection Option: (Continued)

(5) Bill Protection benefits are computed on a cumulative basis at the end of the customer's Commitment Period and, if applicable, a Bill Protection credit shall appear on the customer's bill following the end of the Commitment Period.

(D)

(Continued)

Schedule GS2-TOU-CPP Sheet 6

GENERAL SERVICE-TIME-OF-USE-DEMAND METERED
CRITICAL PEAK PRICING-VOLUMETRIC CHARGE DISCOUNT-VCD

(Continued)

SPECIAL CONDITIONS (Continued)

8. Customer Site Visits: All customers served under this Schedule automatically grant, as a stipulation of their participation on this Schedule, the California Energy Commission (CEC), or its contracted agents, the authorization to conduct site visits for measurement and evaluation purposes, as well as granting the CEC, or its contracted agents, the authorization to request and receive measurement and/or evaluation information from participating customers. Additionally, all customers served under this Schedule agree to complete all program evaluation surveys conducted by the CEC, or its contracted agents. (T)

9. Associated Service Accounts: Customers served under this Schedule with otherwise eligible service accounts located on the same or immediately adjacent Premises as the service account currently receiving service under this Schedule may choose to have one or all of such service accounts served under an applicable CPP schedule without meeting the Maximum Demand requirements, as long as at least one account remains above 200 kW at all times and such service account receives service under an applicable CPP schedule.

10. Voltage: Service will be supplied at one standard voltage.

11. Maximum Demand: The maximum demand shall be established for each monthly billing period. Maximum demand shall be measured by taking the maximum average kilowatt input indicated or recorded by instruments, during any 15-minute metered interval, but, where applicable, not less than the diversified resistance welder load computed in accordance with the section designated Welder Service in Rule 2. Where the demand is intermittent or subject to violent fluctuations, a 5-minute interval may be used.

12. Billing Demand: The Billing Demand shall be the kilowatts of Maximum Demand, determined to the nearest kW. The Demand Charge shall include the following billing components. The Time Related Component shall be for the kilowatts of Maximum Demand recorded during (or established for) the applicable TOU period of monthly billing period. The Facilities Related Component shall be for the kilowatts of Maximum Demand recorded during (or established for) the monthly billing period. However, when SCE determines the customer's meter will record little or no energy use for extended periods of time or when the customer's meter has not recorded a Maximum Demand in the preceding eleven months, the Facilities Related Component of the Demand Charge may be established at 50 percent of the customer's connected load. (T) (D) (D)

13. Single-Phase Service: Where SCE provides single-phase service, the billing will be reduced by the amount shown in the Rates section, above.

(D)

14. Voltage Discount: Bundled Service and Direct Access Customers will have the Distribution rate component of the applicable Delivery Service charges reduced by the corresponding Voltage Discount amount for service metered and delivered at the applicable voltage level as shown in the Rates section above. In addition, Bundled Service Customers will have the Utility Retained Generating (URG) rate component of the applicable Generation charges reduced by the corresponding Voltage Discount amount for service metered and delivered at the applicable voltage level as shown in the Rates section. (C)

(Continued)

Schedule GS2-TOU-CPP Sheet 7

GENERAL SERVICE-TIME-OF-USE-DEMAND METERED
CRITICAL PEAK PRICING-VOLUMETRIC CHARGE DISCOUNT-VCD

(Continued)

SPECIAL CONDITIONS (Continued)

15. Power Factor Adjustment. When the Maximum Demand has exceeded 200 kW for three consecutive months, kilovar metering will be installed as soon as practical, and, thereafter, until the Maximum Demand has been less than 150 kW for twelve consecutive months, the billing will be increased each month for power factor by the amount shown in the Rates section above for service metered and delivered at the applicable voltage level, based on the per kilovar of maximum Reactive Demand imposed on SCE. The reactive demand will be determined as follows: (T)

a. Service metered and delivered at voltages of 4 kV or greater and for all Cogeneration and Small Power Production customers:

The maximum reactive demand shall be the highest measured maximum average kilovar demand indicated or recorded by metering during any 15-minute metered interval in the month. The kilovars shall be determined to the nearest unit. A device will be installed on each kilovar meter to prevent reverse operation of the meter.

b. Service metered and delivered at voltages Less than 4 kV:

(1) For customers with metering used for billing that measures reactive demand.

The maximum reactive demand shall be the highest measured maximum average kilovar demand indicated or recorded by metering during any 15-minute metered interval in the month. The kilovars shall be determined to the nearest unit. A device will be installed on each kilovar meter to prevent reverse operation of the meter.

(2) For customers with metering used for billing that measures kilovar-hours instead of reactive demand.

The kilovars of reactive demand shall be calculated by multiplying the kilowatts of measured maximum demand by the ratio of the kilovar-hours to the kilowatthours. Demands in kilowatts and kilovars shall be determined to the nearest unit. A ratchet device will be installed on the kilovar-hour meter to prevent its reverse operation on leading power factors.

16. Temporary Discontinuance of Service: When the use of energy is seasonal or intermittent, no adjustments will be made for a temporary discontinuance of service. Any customer prior to resuming service within twelve months after such service was discontinued will be required to pay all charges which would have been billed if service had not been discontinued. (T)

(Continued)

Schedule GS2-TOU-CPP Sheet 8

GENERAL SERVICE-TIME-OF-USE-DEMAND METERED
CRITICAL PEAK PRICING-VOLUMETRIC CHARGE DISCOUNT-VCD

(Continued)

SPECIAL CONDITIONS (Continued)

17. Customer-Owned Electrical Generating Facilities:

    a. Where customer-owned electrical generating facilities are used to meet a part or all of the customer's electrical requirements, service shall be provided concurrently under the terms and conditions of Schedule S and this Schedule. Parallel operation of such generating facilities with SCE's electrical system is permitted. A generation interconnection agreement is required for such operation.

    b. Customer-owned electrical generating facilities used solely for auxiliary, emergency, or standby purposes (auxiliary/emergency generating facilities) to serve the customer's load during a period when SCE's service is unavailable and when such load is isolated from the service of SCE are not subject to Schedule S. However, upon approval by SCE, momentary parallel operation may be permitted to allow the customer to test the auxiliary/emergency generating facilities. A Momentary Parallel Generation Contract is required for this type of service.

18. CARE Discount: Customers who meet the definition of a Group Living Facility, Agricultural Employee Housing, or Migrant Farm Worker Housing Center as defined in the Preliminary Statement, Part O, Section 3., may qualify for a 26.7% discount off of their bill prior to application (I) of the PUC Reimbursement Fee and any applicable user fees, taxes, and late payment charges. Customers eligible for the CARE Discount will not be required to pay the CARE Surcharge, as set forth in Preliminary Statement, Part O, Section 4 and are not subject to the DWRBC rate component of the Total charges for Delivery Service. An Application and Eligibility Declaration, as defined in the Preliminary Statement, Part O, Section 3., is required for service under this Special Condition. Eligible customers shall be billed on this Schedule commencing no later than one billing period after receipt and approval of the customer's application by SCE. Customers may be rebilled on the applicable rate schedule for periods in which they do not meet the eligibility requirements for the CARE discount as defined in the Preliminary Statement, Part O, Section 3.

19. Billing Calculation: A customer’s bill is first calculated according to the total rates and conditions above. The following adjustments are made depending on the option applicable to the customer.

    Except for the Energy Charge, the charges listed in the Rates section are calculated by multiplying the Total Delivery Service rates and the Generation rates, when applicable, by the billing determinants (e.g., per kilowatt [kW], kilowatthour [kWh], kilovar [kVa] etc.),

    The Energy Charge, however, is determined by multiplying the total kWhs by the Total Delivery Service per kWh rates to calculate the Delivery Service amount of the Charge. To calculate the Generation amount, SCE determines what portion of the total kWhs is supplied by the Utility Retained Generation (URG) and the Department of Water Resources (DWR). The kWhs supplied by the URG are multiplied by the URG per kWh rates and the kWhs supplied by the DWR are multiplied by the DWR per kWh rate and the two products are summed to arrive at the Generation amount. The Energy Charge is the sum of the Delivery Service amount and the Generation amount.

    For each billing period, SCE determines the portion of total kWhs supplied by SCE’s URG and by the DWR. This determination is made by averaging the daily percentages of energy supplied to SCE’s Bundled Service Customers by SCE’s URG and by the DWR.

    Bundled Service Customers receive Delivery Service from SCE and receive supply (Gen) service from both SCE’s URG and the DWR. The customer’s bill is the sum of the charges for Delivery Service and Gen determined, as described in this Special Condition, and subject to applicable discounts or adjustments provided under SCE’s tariff schedules.

(Continued)

Schedule GS2-TOU-CPP — Sheet 9

GENERAL SERVICE-TIME-OF-USE-DEMAND METERED
CRITICAL PEAK PRICING-VOLUMETRIC CHARGE DISCOUNT-VCD
(Continued)

SPECIAL CONDITIONS (Continued)

20. Customers with Service Metered and Delivered at Voltages above 50 kV (Sub-transmission customers) Included in Rotating Outages.

Sub-transmission customers, except for those customers exempt from rotating outages, are to be included in controlled, rotating outages when required by the Independent System Operator (ISO) and/or SCE. To the extent feasible, SCE will coordinate rotating outages (T) applicable to Sub-transmission customers who are fossil fuel producers and pipeline operators and users to minimize disruption to public health and safety. SCE shall not include a Sub-transmission customer in an applicable rotating outage group if the customer's inclusion would jeopardize electric system integrity. Sub-transmission customers who are not exempt from rotating outages, and seek such exemption, may submit an Optional Binding Mandatory Curtailment (OBMC) Plan to SCE in accordance with Schedule OBMC. If SCE approves a customer's OBMC Plan, the customer will become exempt from rotating outages and will be subject to the terms and conditions of Schedule OBMC and its associated contract.

Non-exempt Sub-transmission customers shall be required to drop their entire electrical load during applicable rotating outages by either (1) implementing the load reduction on their own initiative, in accordance with subsection a, below; or (2) having SCE implement the load reduction through remote-controlled load drop equipment (control equipment) in accordance with subsection b, below. A Sub-transmission customer shall normally be subject to the provisions of subsection a. If SCE approves a customer's request to have SCE implement the load reduction or if the customer does not did not comply with prior required load reductions, as specified in subsection c, the customer will be subject to the provisions of subsection b.

a. Customer-Implemented Load Reduction.

(i) Notification of Required Load Reduction. At the direction of the ISO or when (T) SCE otherwise determines there is a need for Rotating Outage, SCE shall (T) notify each Sub-transmission customers in an affected rotating outage group to drop its entire load. Within 30 minutes of such notification, the customer must drop its entire load. The customer shall not return the dropped load to service until 90 minutes after SCE sent the notification to the customer to drop its load, unless SCE notifies the customer that it may return its load to service prior to the expiration of the 90 minutes.

(ii) Method of Notification. SCE will notify Sub-transmission customers who are required to implement their own load reduction via telephone, by either an automated calling system or a manual call to a business telephone number or cellular phone number designated by the customer. The designated telephone number will be used for the sole purpose of receiving SCE's rotating outage notification and must be available to receive the notification at all times. When SCE sends the notification to the designated telephone number the customer is responsible for dropping its entire load in accordance with subsection a. (i)., above. The customer is responsible for informing SCE, in writing, of the telephone number and contact name for purposes of receiving the notification of a rotating outage.

(Continued)

Schedule GS2-TOU-CPP Sheet 10
GENERAL SERVICE-TIME-OF-USE-DEMAND METERED
CRITICAL PEAK PRICING-VOLUMETRIC CHARGE DSCOUNT-VCD
(Continued)

SPECIAL CONDITIONS (Continued)

20. Customers with Service Metered and Delivered at Voltages above 50 kV (Sub-transmission customers) Included in Rotating Outages. (Continued) (T)

a. Customer-Implemented Load Reduction. (Continued)

(iii) Excess Energy Charges. If a Sub-transmission customer fails to drop its entire load within 30 minutes of notification by SCE, and/or fails to maintain the entire load drop until 90 minutes after the time notification was sent to the customer, unless SCE otherwise notified the customer that it may return its load to service earlier in accordance with subsection a. (i) above, SCE shall assess Excess Energy Charges of $6 per kWh for all kWh usage in excess of the Authorized Residual Ancillary Load. Such charges will be based on the total kWh usage during the applicable rotating outage penalty period, less the product of Authorized Residual Ancillary Load in kW and the applicable rotating outage penalty period in hours. Excess Energy Charges will be determined and applied by SCE subsequent to the Sub-transmission customer's regularly scheduled meter read date following the applicable rotating outage.

For customers with net-generators, Excess Energy Charges shall not apply during periods of verifiable scheduled generator maintenance or if the customer's generator suffers a verified forced outage. The scheduled maintenance must be approved in advance by both the ISO and SCE, but approval may not be unreasonably held.

(iv) Authorized Residual Ancillary Load. Authorized Residual Ancillary Load is load that is deemed to be equivalent to five percent of the Sub-transmission customer's prior billing month's recorded Maximum Demand. This minimum load level is used as a proxy to allow for no-load transformer losses and load attributed to minimum grid parallel operation for generators connected under Rule 21.

b. SCE-Implemented Load Reduction.

Non-exempt Sub-transmission customers may request, in writing, to have SCE drop the customer's entire load during all applicable rotating outages using SCE's remote-controlled load drop equipment (control equipment). If SCE agrees to such arrangement, SCE will implement the load drop by using one of the following methods:

(i) Control Equipment Installed. For a Sub-transmission customer whose load can be dropped by SCE's existing control equipment, SCE will implement the load drop during a rotating outage applicable to the customer. The customer will not be subject to the Notification and or Excess Energy Charge provisions set forth in subsection a, above.

(Continued)

Schedule GS2-TOU-CPP — Sheet 11

GENERAL SERVICE-TIME-OF-USE-DEMAND METERED
CRITICAL PEAK PRICING-VOLUMETRIC CHARGE DISCOUNT-VCD

(Continued)

SPECIAL CONDITIONS (Continued)

20. Customers with Service Metered and Delivered at Voltages above 50 kV (Sub-transmission customers) Included in Rotating Outages. (Continued) (T)

b. SCE-Implemented Load Reduction. (Continued)

(ii) Control Equipment Pending Installation. For a Sub-transmission customer whose load can not be dropped by SCE's existing control equipment, the customer must request the installation of such equipment at the customer's expense in accordance with SCE's Rule 2, Section H, Added Facilities. Pending the installation of the control equipment, the customer will be responsible for dropping load in accordance with the provisions of subsection a, above, including subject the Notification and Excess Energy Charge provisions.

c. Non-compliance: A non-exempt Sub-transmission customer subject to subsection a, above, who fails to drop load during three rotating outages in a three year period to a level of at least 20% of the customer's prior billing month's recorded Maximum Demand averaged over the applicable rotating outage period, is not in compliance with this tariff. The three year period shall commence with the first failure to drop load as specified in this subsection. A customer not in compliance with this condition will be placed at the top of the Sub-transmission customer rotating outage group list and will be expected to comply with subsequent applicable rotating outages. In addition, the customer must select one of the two options below within fifteen days after receiving written notice of non-compliance from SCE. A customer failing to make a selection within the specified time frame will be subject to subsection c. (ii) below.

(i) Subject to Schedule OBMC: The customer shall submit an OBMC Plan, in accordance with Schedule OBMC, within 30 calendar days of receiving written notice of non-compliance from SCE. Pending the submittal of the OBMC Plan by the customer and pending the review and acceptance of the OBMC Plan by SCE, the customer will remain responsible for dropping load in accordance with the provisions of subsection a, above, including the Notification and Excess Energy charge provisions. If the customer fails to submit an OBMC Plan within 30 days of receiving notice of non-compliance from SCE, or if the customer's OBMC Plan is not approved by SCE, or if the customer fails to meet the requirements of Schedule OBMC once the OBMC Plan is approved, the customer shall be subject subsection c. (ii), below.

(ii) Installation of Control Equipment. The customer shall be subject to the installation of control equipment at the customer's expense in accordance with SCE's Rule 2, Section H, Added Facilities, if such equipment is not currently installed. If such switching capability is installed, SCE will drop the customer's load for all applicable subsequent rotating outages in accordance with the provisions of subsection b, above. Pending the installation of control equipment, the customer will remain responsible for dropping load in accordance with the provisions of subsection a, above, including the Notification and Excess Energy Charge provisions.

Schedule GS2-TOU-CPP Sheet 12
GENERAL SERVICE-TIME-OF-USE-DEMAND METERED
CRITICAL PEAK PRICING-VOLUMETRIC CHARGE DISCOUNT-VCD
(Continued)

SPECIAL CONDITIONS (Continued)

20. Customers with Service Metered and Delivered at Voltages above 50 kV (Sub-transmission customers) Included in Rotating Outages. (Continued)

d. Net-Generators

Sub-transmission customers who are also net-generators are normally exempt from rotating outages, but they must be net suppliers of power to the grid during all rotating outages. For the purpose of this Special Condition, a net-generator is an SCE customer who operates an electric generating facility as part of its industrial or commercial process, and the generating facility normally produces more electrical power than is consumed in the industrial or commercial process, with the excess power supplied to the grid. Sub-transmission customers whose primary business purpose is to generate power are not included in this Special Condition.

(i) Notification of Rotating Outages. SCE will notify sub-transmission customers who are net-generators of all rotating outages applicable to customers within SCE's service territory. Within 30 minutes of notification, the customer must ensure it is a net supplier of power to the grid throughout the entire rotating outage period. Failure to do so will result in the customer losing its exemption from rotating outages, and the customer will be subject to Excess Energy Charges, as provided below.

(ii) Excess Energy Charges. Net generators who are not net suppliers to the grid during each rotating outage period will be subject to Excess Energy Charges of $6 per kWh for all kWh usage in excess of the Authorized Residual Ancillary Load. Such charges will be based on the total kWh usage during a rotating outage penalty period, less the product of Authorized Residual Ancillary Load in kW and the applicable rotating outage period hours. Excess Energy Charges will be determined and applied by SCE subsequent to the customer's regularly scheduled meter read date following the applicable rotating outage. Excess Energy Charges shall not apply during periods of verifiable scheduled generator maintenance or if the customer's generator suffers a verifiable forced outage. The scheduled maintenance must be approved in advance by either the ISO or SCE, but approval may not be unreasonably withheld.

Schedule TOU-8-CPP — Sheet 1
TIME-OF-USE-GENERAL SERVICE-LARGE
CRITICAL PEAK PRICING-VOLUMETRIC CHARGE DISCOUNT-VCD

APPLICABILITY

This Schedule is optional for Bundled Service Customers currently served under Schedule TOU-8, with maximum demands above 500 kW, defined herein as registered Maximum Demand of greater than 500 kW in any three months during the preceding twelve months. A customer served under this Schedule whose monthly Maximum Demand has registered less than 500 kW for twelve consecutive months is ineligible for service under Schedule and shall be transferred to Schedule GS2-TOU-CPP. Customer service accounts served under Schedule S are not eligible for service under this Schedule. A customer's participation in other demand response programs may affect a customer's eligibility for service under this Schedule, or the level of credits available under such other programs (see Special Conditions section). The required interval metering equipment, as defined in this Schedule's Special Conditions section, is mandatory prior to participation on this Schedule and is subject to the availability of such metering. Customers currently served under Schedule I-6, TOU-BIP, or OBMC may not concurrently receive service under this Schedule.

TERRITORY

Within the entire territory served.

RATES

The following rates set forth for service metered and delivered at secondary, primary, and subtransmission voltages.

SERVICE METERED AND DELIVERED AT VOLTAGES BELOW 2 KV

	Delivery Service							Gen[8]	
	Trans[1]	Distrbtn[2]	NDC[3]	PPPC[4]	PUCRF[5]	DWRBC[6]	Total[7]	URG*	DWR
Energy Charge - $/kWh/Meter/Month									
CPP Event									
Summer Season									
CPP Moderate-Price Period									
Noon – 3:00 p.m.	0.00126	0.00495 (I)	0.00048	0.00725 (I)	0.00012 (I)	0.00485	0.01891 (I)	0.43113 (I)	0.10369
CPP High-Price Period									
3:00 p.m. – 6:00 p.m.	0.00126	0.00495 (I)	0.00048	0.00725 (I)	0.00012 (I)	0.00485	0.01891 (I)	1.23601 (I)	0.10369
Non CPP Event Time Periods									
Summer Season – On-Peak	0.00126	0.00495 (I)	0.00048	0.00725 (I)	0.00012 (I)	0.00485	0.01891 (I)	0.13082	0.10369
Mid-Peak	0.00126	0.00495 (I)	0.00048	0.00725 (I)	0.00012 (I)	0.00485	0.01891 (I)	0.04988	0.10369
Off-Peak	0.00126	0.00495 (I)	0.00048	0.00725 (I)	0.00012 (I)	0.00485	0.01891 (I)	0.00901	0.10369
Winter Season Mid-Peak	0.00126	0.00495 (I)	0.00048	0.00725 (I)	0.00012 (I)	0.00485	0.01891 (I)	0.08105	0.10369
Off-Peak	0.00126	0.00495 (I)	0.00048	0.00725 (I)	0.00012 (I)	0.00485	0.01891 (I)	0.01193	0.10369
Customer Charge - $/Meter/Month		291.66 (I)					291.66 (I)		
Demand Charge - $/kW of Billing Demand/Meter/Month									
Facilities Related	1.26	5.29 (I)					6.55 (I)	2.20	
Time Related									
Summer Season									
On-Peak (including CPP High-Price/ Moderate-Price Periods)		9.06 (I)					9.06 (I)	19.94	
Mid-Peak		0.77 (I)					0.77 (I)	4.13	
Off-Peak		0.00					0.00	0.00	
Winter Season – On-Peak		N/A					N/A	N/A	
Mid-Peak		0.00					0.00	0.00	
Off-Peak		0.00					0.00	0.00	

(Continued)

Schedule TOU-8-CPP Sheet 2

TIME-OF-USE-GENERAL SERVICE-LARGE

CRITICAL PEAK PRICING-VOLUMETRIC CHARGE DISCOUNT-VCD

(Continued)

RATES (Continued)

SERVICE METERED AND DELIVERED AT VOLTAGES BELOW 2 kV (Continued)

	Delivery Service							Gen[8]	
	Trans[1]	Distrbtn[2]	NDC[3]	PPPC[4]	PUCRF[5]	DWRBC[6]	Total[7]	URG*	DWR
Power Factor Adjustment - $/kVA		0.19					0.19		

* The ongoing Competition Transition Charge (CTC) of $0.00909 is recovered in the URG component of Generation.

1 Trans = Transmission and the Transmission Owners Tariff Charge Adjustments (TOTCA) which are FERC approved. The TOTCA represents the Transmission Revenue Balancing Account Adjustment (TRBAA) of negative $(0.00124) per kWh, Reliability Services Balancing Account Adjustment (RSBAA) of $0.00168 per kWh, and Transmission Access Charge Balancing Account Adjustment (TACBAA) of $0.00082 per kWh.

2 Distrbtn = Distribution

3 NDC = Nuclear Decommissioning Charge

4 PPPC = Public Purpose Programs Charge (includes California Alternate Rates for Energy Surcharge where applicable.)

5 PUCRF = The PUC Reimbursement Fee is described in Schedule RF-E.

6 DWRBC = Department of Water Resources (DWR) Bond Charge. The DWR Bond Charge is not applicable to exempt Bundled Service and Direct Access Customers, as defined in and pursuant to D.02-10-063, D.02-02-051, and D.02-12-082.

7 Total = Total Delivery Service rates that are applicable to both Bundled Service and Direct Access (DA) Customers, except DA Customers are not subject to the DWRBC rate component of this Schedule but instead pay the DWRBC as provided by Schedule DA.

8 Gen = Generation – The Gen rates are applicable only to Bundled Service Customers. When calculating the Energy Charge, the Gen portion is calculated as described in the Billing Calculation Special Condition of this Schedule.

SERVICE METERED AND DELIVERED AT VOLTAGES FROM 2 KV to 50 KV (Continued)

	Delivery Service							Gen[8]	
	Trans[1]	Distrbtn[2]	NDC[3]	PPPC[4]	PUCRF[5]	DWRBC[6]	Total[7]	URG*	DWR
Energy Charge - $/kWh/Meter/Month									
CPP Event									
Summer Season									
CPP Moderate-Price Period									
Noon – 3:00 p.m.	0.00104	0.00409 (I)	0.00048	0.00700 (I)	0.00012 (I)	0.00485	0.01758 (I)	0.44191 (I)	0.10369
CPP High-Price Period									
3:00 p.m. – 6:00 p.m.	0.00104	0.00409 (I)	0.00048	0.00700 (I)	0.00012 (I)	0.00485	0.01758 (I)	1.27502 (I)	0.10369
Non CPP Event Time Periods									
Summer Season – On-Peak	0.00104	0.00409 (I)	0.00048	0.00700 (I)	0.00012 (I)	0.00485	0.01758 (I)	0.13962	0.10369
Mid-Peak	0.00104	0.00409 (I)	0.00048	0.00700 (I)	0.00012 (I)	0.00485	0.01758 (I)	0.05440	0.10369
Off-Peak	0.00104	0.00409 (I)	0.00048	0.00700 (I)	0.00012 (I)	0.00485	0.01758 (I)	0.01429	0.10369
Winter Season Mid-Peak	0.00104	0.00409 (I)	0.00048	0.00700 (I)	0.00012 (I)	0.00485	0.01758 (I)	0.08361	0.10369
Off-Peak	0.00104	0.00409 (I)	0.00048	0.00700 (I)	0.00012 (I)	0.00485	0.01758 (I)	0.01725	0.10369
Customer Charge - $/Meter/Month		292.01 (I)					292.01 (I)		

(Continued)

Schedule TOU-8-CPP Sheet 3
TIME-OF-USE-GENERAL SERVICE-LARGE
CRITICAL PEAK PRICING-VOLUMETRIC CHARGE DISCOUNT-VCD
(Continued)

RATES (Continued)

SERVICE METERED AND DELIVERED AT VOLTAGES FROM 2 KV TO 50 KV (Continued)

	Delivery Service							Gen[8]	
	Trans[1]	Distrbtn[2]	NDC[3]	PPPC[4]	PUCRF[5]	DWRBC[6]	Total[7]	URG*	DWR
Demand Charge - $/kW of Billing Demand/Meter/Month									
Facilities Related	1.31	4.86 (I)					6.17 (I)	2.34	
Time Related									
Summer Season									
On-Peak (including CPP High-Price/ Moderate-Price Periods)		8.50 (I)					8.50 (I)	21.21	
Mid-Peak		0.72 (I)					0.72 (I)	4.11	
Off-Peak		N/A					N/A	N/A	
Winter Season – On-Peak		N/A					N/A	N/A	
Mid-Peak		0.00					0.00	0.00	
Off-Peak		0.00					0.00	0.00	
Power Factor Adjustment - $/kVA		0.19					0.19		

* The ongoing Competition Transition Charge (CTC) of $0.00827 is recovered in the URG component of Generation.

1 Trans = Transmission and the Transmission Owners Tariff Charge Adjustments (TOTCA) which are FERC approved. The TOTCA represents the Transmission Revenue Balancing Account Adjustment (TRBAA) of negative $(0.00124) per kWh, Reliability Services Balancing Account Adjustment (RSBAA) of $0.00146 per kWh, and Transmission Access Charge Balancing Account Adjustment (TACBAA) of $0.00082 per kWh.

2 Distrbtn = Distribution

3 NDC = Nuclear Decommissioning Charge

4 PPPC = Public Purpose Programs Charge (includes California Alternate Rates for Energy Surcharge where applicable.)

5 PUCRF = The PUC Reimbursement Fee is described in Schedule RF-E.

6 DWRBC = Department of Water Resources (DWR) Bond Charge. The DWR Bond Charge is not applicable to exempt Bundled Service and Direct Access Customers, as defined in and pursuant to D.02-10-063, D.02-02-051, and D.02-12-082.

7 Total = Total Delivery Service rates that are applicable to both Bundled Service and Direct Access (DA) Customers, except DA Customers are not subject to the DWRBC rate component of this Schedule but instead pay the DWRBC as provided by Schedule DA.

8 Gen = Generation – The Gen rates are applicable only to Bundled Service Customers. When calculating the Energy Charge, the Gen portion is calculated as described in the Billing Calculation Special Condition of this Schedule.

SERVICE METERED AND DELIVERED AT VOLTAGES ABOVE 50 KV

	Delivery Service							Gen[8]	
	Trans[1]	Distrbtn[2]	NDC[3]	PPPC[4]	PUCRF[5]	DWRBC[6]	Total[7]	URG*	DWR
Energy Charge - $/kWh/Meter/Month									
CPP Event									
Summer Season									
CPP Moderate-Price Period									
Noon – 3:00 p.m.	0.00088	0.00118 (I)	0.00048	0.00579 (I)	0.00012 (I)	0.00485	0.01330 (I)	0.39589	0.10369
CPP High-Price Period									
3:00 p.m. – 6:00 p.m.	0.00088	0.00118 (I)	0.00048	0.00579 (I)	0.00012 (I)	0.00485	0.01330 (I)	1.05972 (I)	0.10369
Non CPP Event Time Periods									
Summer Season – On-Peak	0.00088	0.00118 (I)	0.00048	0.00579 (I)	0.00012 (I)	0.00485	0.01330 (I)	0.10990	0.10369
Mid-Peak	0.00088	0.00118 (I)	0.00048	0.00579 (I)	0.00012 (I)	0.00485	0.01330 (I)	0.04870	0.10369
Off-Peak	0.00088	0.00118 (I)	0.00048	0.00579 (I)	0.00012 (I)	0.00485	0.01330 (I)	0.02361	0.10369
Winter Season Mid-Peak	0.00088	0.00118 (I)	0.00048	0.00579 (I)	0.00012 (I)	0.00485	0.01330 (I)	0.07586	0.10369
Off-Peak	0.00088	0.00118 (I)	0.00048	0.00579 (I)	0.00012 (I)	0.00485	0.01330 (I)	0.02689	0.10369
Customer Charge - $/Meter/Month		341.28 (I)					341.28 (I)		
Demand Charge-$/kW of Billing Demand/Meter/Month									
Facilities Related	1.25	0.28					1.53	0.00	

(Continued)

Schedule TOU-8-CPP Sheet 4

TIME-OF-USE-GENERAL SERVICE-LARGE

CRITICAL PEAK PRICING-VOLUMETRIC CHARGE DISCOUNT-VCD

(Continued)

RATES (Continued)

SERVICE METERED AND DELIVERED AT VOLTAGES ABOVE 50 KV (Continued)

	Delivery Service							Gen[8]	
	Trans[1]	Distrbtn[2]	NDC[3]	PPPC[4]	PUCRF[5]	DWRBC[6]	Total[7]	URG*	DWR
Time Related									
Summer Season									
On-Peak (including CPP High-Price/ Moderate-Price Periods)		5.94 (I)					5.94 (I)	18.69	
Mid-Peak		0.51					0.51	3.61	
Off-Peak		0.00					0.00	0.00	
Winter Season – On-Peak		N/A					N/A	N/A	
Mid-Peak		0.00					0.00	0.00	
Off-Peak		0.00					0.00	0.00	
Power Factor Adjustment - $/kVA		0.17					0.17		
Voltage Discount, Demand 220 kV and above -$/kW									
Facilities Related		(0.33)					(0.33)	0.00	
Time Related									
Summer		(3.51)					(3.51)	(0.05)	
Voltage Discount, Energy 220 kV - $/kWh		0.00000					0.00000	(0.00054)	

* The ongoing Competition Transition Charge (CTC) of $0.00665 is recovered in the URG component of Generation.

1 Trans = Transmission and the Transmission Owners Tariff Charge Adjustments (TOTCA) which are FERC approved. The TOTCA represents the Transmission Revenue Balancing Account Adjustment (TRBAA) of negative $(0.00124) per kWh, Reliability Services Balancing Account Adjustment (RSBAA) of $0.00130 per kWh, and Transmission Access Charge Balancing Account Adjustment (TACBAA) of $0.00082 per kWh. (I)

2 Distrbtn = Distribution

3 NDC = Nuclear Decommissioning Charge

4 PPPC = Public Purpose Programs Charge (includes California Alternate Rates for Energy Surcharge where applicable.)

5 PUCRF = The PUC Reimbursement Fee is described in Schedule RF-E.

6 DWRBC = Department of Water Resources (DWR) Bond Charge. The DWR Bond Charge is not applicable to exempt Bundled Service and Direct Access Customers, as defined in and pursuant to D.02-10-063, D.02-02-051, and D.02-12-082.

7 Total = Total Delivery Service rates that are applicable to both Bundled Service and Direct Access (DA) Customers, except DA Customers are not subject to the DWRBC rate component of this Schedule but instead pay the DWRBC as provided by Schedule DA.

8 Gen = Generation – The Gen rates are applicable only to Bundled Service Customers. When calculating the Energy Charge, the Gen portion is calculated as described in the Billing Calculation Special Condition of this Schedule.

(Continued)

Schedule TOU-8-CPP — Sheet 5

TIME-OF-USE-GENERAL SERVICE-LARGE

CRITICAL PEAK PRICING-VOLUMETRIC CHARGE DISCOUNT-VCD

(Continued)

SPECIAL CONDITIONS

1. Time periods are defined as follows:

CPP Moderate–Price Period: Noon to 3:00 p.m. during a CPP Event only

CPP High-Price Period: 3:00 p.m. to 6:00 p.m. during a CPP Event only

On-Peak: Noon to 6:00 p.m. summer weekdays except CPP Moderate-Price Periods, CPP High-Price Periods, and holidays

Mid-Peak: 8:00 a.m. to Noon and 6:00 p.m. to 11:00 p.m. summer weekdays except holidays
8:00 a.m. to 9:00 p.m. winter weekdays except holidays

Off-Peak: All other hours.

Holidays are New Year's Day (January 1), Washington's Birthday (third Monday in February), Memorial Day (last Monday in May), Independence Day (July 4), Labor Day (first Monday in September), Veterans Day (November 11), Thanksgiving Day (fourth Thursday in November), and Christmas (December 25).

When any holiday listed above falls on Sunday, the following Monday will be recognized as an off-peak period. No change will be made for holidays falling on Saturday.

The summer season shall commence at 12:00 a.m. on the first Sunday in June and continue until 12:00 a.m. of the first Sunday in October of each year. The winter season shall commence at 12:00 a.m. on the first Sunday in October and continue until 12:00 a.m. of the first Sunday in June of the following year.

2. CPP Events: SCE may, at its discretion, invoke a CPP Event during the summer season time period of Noon to 6:00 p.m. when SCE determines any of the following conditions exist: there is high system peak demand and/or low generation reserves; system constraints; high wholesale market prices; a Los Angeles Civic Center temperature of 87 degrees or above by 2 p.m. the day prior to a CPP Event; special alerts issued by California Independent System (T) Operator (CAISO); and/or for testing/evaluation purposes. SCE will adjust the temperature threshold up or down, on a bi-monthly basis, to achieve the CPP program design basis of 12 (T) CPP Events per summer season.

(D)

3. Number of CPP Events: CPP Events will be invoked by SCE during the summer season and shall be limited to 12 CPP Events, which includes up to four events for testing/evaluation (T) purposes.

4. Notification of a CPP Event: SCE will notify customers of a CPP Event via SCE's notification system. SCE's primary notification method will be via telephone call, but the customer may also elect to receive notification via pager, electronic mail, cellular telephone, or by fax as a courtesy. SCE will begin to notify customers by 3:00 p.m. the day before a CPP Event. If (T) SCE cannot contact the customer on the first attempt, at least two more attempts will be made. However, SCE does not guarantee customer receipt of the notification. Customers will be responsible for all charge incurred during a CPP Event, even if actual notice is not received.

(D)

5. Participation in other Programs: Customers served under this Schedule may also participate on SCE's Demand Bidding Program (DBP) or the California Power Authority Demand Reserves Partnership Program (CPA DRP), but will be ineligible for any energy credits under these programs during a CPP Event.

(Continued)

Schedule TOU-8-CPP Sheet 6
TIME-OF-USE-GENERAL SERVICE-LARGE
CRITICAL PEAK PRICING-VOLUMETRIC CHARGE DISCOUNT-VCD
(Continued)

SPECIAL CONDITIONS (Continued)

6. Required Metering and Notification Equipment: Prior to participation on this Schedule, a customer must have Interval Metering and a designated primary phone line capable of receiving CPP Event notifications. Metering equipment must be in operation for at least ten (10) weekdays (non holidays) prior to participation on this Schedule to establish a customer's Customer Specific Energy Baseline (CSEB).

7. Transitional Incentive Option: A Bill Protection option is available to eligible customers served under this Schedule. Customers who do not, or can not, participate in the Bill Protection Option will be subject to the charges under this Schedule at all times. Customers who meet the conditions outlined below may participate in the following Transitional Incentive Option: (T) (T) (T)

   a. Bill Protection Option:

      (1) A participating customer may receive a Bill Protection credit for the difference in total charges, when such charges, as calculated under this Schedule, exceed total charges as calculated under the customer's Otherwise Applicable Tariff (OAT), as measured over a period of 12 months from the date the customer elects this option (Commitment Period). For purposes of this Special Condition a customer's OAT shall be defined as the non-CPP rate schedule from which the customer transferred from, prior to participation on this rate schedule; (T) (T)

      (2) This option will be closed to new customers on all CPP Schedules once SCE determines that 200 MWs of potential load reduction is participating on the Bill Protection Option. Additionally, this option is only available to customers who elect it within the first 30 days of receiving service on this Schedule; (T) (T)

      (3) If a participating customer is either voluntarily or involuntarily removed from this Schedule prior to completion of the Commitment Period, such customer shall not be eligible for any Bill Protection credits for the period such customer was served under this Schedule; (T)

      (4) At the end of the Commitment Period one of the following will occur:

         (a) If a participating customer's bill, as calculated under this Schedule over the entire Commitment Period is greater than their bill as calculated under their OAT over the entire Commitment Period, then such customer will receive a Bill Protection Credit equal to CPP charges minus OAT charges;

         (b) If a participating customer's bill, as calculated under this Schedule over the entire Commitment Period is equal to or less than their bill as calculated under their OAT over the entire Commitment Period, then such customer will not receive a Bill Protection Credit.

(Continued)

Schedule TOU-8-CPP
TIME-OF-USE-GENERAL SERVICE-LARGE
CRITICAL PEAK PRICING
(Continued)

Sheet 7

SPECIAL CONDITIONS (Continued)

7. Transitional Incentive Option: (Continued)

a. Bill Protection Option: (Continued)

(5) Bill Protection benefits are computed on a cumulative basis at the end of the customer's Commitment Period and, if applicable, a Bill Protection credit shall appear on the customer's bill following the end of the Commitment Period.

(D)

(Continued)

Schedule TOU-8-CPP Sheet 8

TIME-OF-USE-GENERAL SERVICE-LARGE

CRITICAL PEAK PRICING-VOLUMETRIC CHARGE DISCOUNT-VCD

(Continued)

SPECIAL CONDITIONS (Continued)

8. Customer Site Visits: All customers served under this Schedule automatically grant, as a stipulation of their participation on this Schedule, the California Energy Commission (CEC), or its contracted agents, the authorization to conduct site visits for measurement and evaluation purposes, as well as granting the CEC, or its contracted agents, the authorization to request and receive measurement and/or evaluation information from participating customers. Additionally, all customers served under this Schedule agree to complete all program evaluation surveys Conducted by the CEC, or its contracted agents. (T)

9. Associated Accounts: Customers served under this Schedule with accounts located on the same premise as the account currently being served under this Schedule may chose to have one or all of such accounts served under an applicable CPP schedule without meeting the Maximum Demand requirements, as long as at least one account remains above 200 kW at all times and such account receives service under an applicable CPP schedule.

10. Voltage: Service will be supplied at one standard voltage.

11. Maximum Demand: Maximum demands shall be established for the On-Peak, Mid-Peak, and Off-Peak periods. The maximum demand for each period shall be the measured maximum average kilowatt input indicated or recorded by instruments, during any 15-minute metered interval, but, where applicable, not less than the diversified resistance welder load computed in accordance with the section designated Welder Service in Rule 2. Where the demand is intermittent or subject to violent fluctuations, a 5-minute interval may be used.

12. Billing Demand: The Billing Demand shall be the kilowatts of Maximum Demand, determined to the nearest kW. The Demand Charge shall include the following billing components. The Time Related Component shall be for the kilowatts of Maximum Demand recorded during (or established for) the monthly billing period for each of the On-Peak, Mid-Peak, and Off-Peak Time Periods. The Facilities Related Component shall be for the kilowatts of Maximum Demand (D) recorded during (or established for) the monthly billing period. However, when SCE determines (D) the customer's meter will record little or no energy use for extended periods of time or when the customer's meter has not recorded a Maximum Demand in the preceding eleven months, the Facilities Related Component of the Demand Charge may be established at 50 percent of the customer's connected load. Separate Demand Charge(s) for the On-Peak and CPP High-Price/Moderate-Price time periods, the Mid-Peak time period, and Off-Peak Time Period shall be established for each monthly billing period. The Demand Charge for each time period shall be based on the Maximum Demand for that time period occurring during the respective monthly billing period. (D)

13. Voltage Discount: Bundled Service and Direct Access Customers receiving service at 220kV will have the Distribution rate component of the applicable Delivery Service charges reduced by the corresponding Voltage Discount amount for service metered and delivered at the applicable voltage level as shown in the Rates section above. In addition, Bundled Service Customers will have the Utility Retained Generation (URG) rate component of the applicable Generation charges reduced by the corresponding Voltage Discount amount for service metered and delivered at the applicable voltage level as shown in the Rates section. (C)

(Continued)

Schedule TOU-8-CPP Sheet 9
TIME-OF-USE-GENERAL SERVICE-LARGE
CRITICAL PEAK PRICING-VOLUMETRIC CHARGE DISCOUNT-VCD
(Continued)

SPECIAL CONDITIONS (Continued)

14. Power Factor Adjustment: The customer's bill will be increased each month for power factor by the amount shown in the Rates section above for service metered and delivered at the applicable voltage level, based on the per kilovar of maximum reactive demand imposed by SCE. (T)

    The maximum reactive demand shall be the highest measured maximum average kilovar demand indicated or recorded by metering during any 15 minute metered interval in the month. The kilovars shall be determined to the nearest unit. A device will be installed on each kilovar meter to prevent reverse operation of the meter.

15. Temporary Discontinuance of Service: Where the use of energy is seasonal or intermittent, no adjustments will be made for a temporary discontinuance of service. Any customer prior to resuming service within twelve months after such service was discontinued will be required to pay all charges which would have been billed if service had not been discontinued. (T)

16. Contract: An initial three-year facilities agreement may be required where applicant requires new or added serving capacity exceeding 2,000 kVA. (T)

17. Customer-Owned Electrical Generating Facilities: Customer-owned electrical generating facilities used solely for auxiliary, emergency, or standby purposes (auxiliary/emergency generating facilities) to serve the customer's load during a period when SCE's service is unavailable and when such load is isolated from the service of SCE are not subject to Schedule S. However, upon approval by SCE, momentary parallel operation may be permitted to allow the customer to test the auxiliary/emergency generating facilities. A Momentary Parallel Generation Contract is required for this type of service. (T)

18. Removal From Schedule: Customers receiving service under this Schedule whose monthly Maximum Demand has registered 500 kW or less for 12 consecutive months shall be changed to rate schedule GS2-TOU-CPP effective with the date the customer became ineligible for service under this Schedule. (T)

19. Agricultural Water Pumping Accounts: Large individual water agency and other large water pumping accounts with 70% or more of the water pumped used for agricultural purposes are not eligible for service under this Schedule and must take service on an agricultural class rate schedule. (T)

(Continued)

Schedule TOU-8-CPP Sheet 10

TIME-OF-USE-GENERAL SERVICE-LARGE

CRITICAL PEAK PRICING-VOLUMETRIC CHARGE DISCOUNT-VCD

(Continued)

SPECIAL CONDITIONS (Continued)

20. Compensated Metering. This provision is applicable to service metered and delivered at voltages above 50 kV. Where customer/applicant requests and SCE agrees, SCE may install a transformer loss compensating device (Compensated Metering) acceptable to SCE in order to provide high voltage (over 50 kV) metered service. Where provided, this service will be considered as metered and delivered on SCE's side of the serving transformer. SCE shall rely on transformer loss data provided by the transformer manufacturer or transformer loss tests performed by SCE to calibrate the compensating device. Service under this provision is contingent upon customer/applicant's entering into an agreement which requires payment for the serving transformer and related substation equipment in accordance with Rule 2., Section H, Added Facilities, except where such transformer equipment is owned, operated, and maintained by the customer/applicant. Where the transformer equipment is owned, operated, and maintained by the customer/applicant, the customer/applicant is required to pay for the Compensated Metering and related equipment in accordance with Rule 2.H, Added Facilities, and shall also agree to provide SCE unrestricted access to the serving transformer, metering, and compensating equipment. (T)

21. Rate Eligibility Criteria for Energy Efficiency (RECEE) (T)
The purpose of the RECEE is to determine a customer's continued eligibility for service under this Schedule. The RECEE is applicable to customers currently receiving service under this Schedule and who have implemented energy efficiency measures on or after June 5, 1994 which have reduced the customer's monthly Maximum Demand to 500 kW or less. The RECEE is a fixed level of demand, determined by SCE, based on the customer's permanent demand reduction resulting from the implementation of energy efficiency measures. The RECEE demand is set forth in the Energy Efficiency Declaration, Form No.16-327.

The RECEE demand plus the customer's actual demand will be evaluated each billing period for purposes of determining the customer's continued eligibility for service under this Schedule. If the RECEE demand plus the customer's actual demand equals 500 kW or less for 12 consecutive months, the customer is ineligible for service under this Schedule and ineligible for application of the RECEE. The RECEE demand will not be used for purposes of calculating the customer's demand charge.

22. Billing Calculation: A customer’s bill is first calculated according to the total rates and conditions above. The following adjustments are made depending on the option applicable to the customer. (T)

Except for the Energy Charge, the charges listed in the Rates section are calculated by multiplying the Total Delivery Service rates and the Generation rates, when applicable, by the billing determinants (e.g., per kilowatt [kW], kilowatthour [kWh], kilovar [kVa] etc.),

The Energy Charge, however, is determined by multiplying the total kWhs by the Total Delivery Service per kWh rates to calculate the Delivery Service amount of the Charge. To calculate the Generation amount, SCE determines what portion of the total kWhs is supplied by the Utility Retained Generation (URG) and the Department of Water Resources (DWR). The kWhs supplied by the URG are multiplied by the URG per kWh rates and the kWhs supplied by the DWR are multiplied by the DWR per kWh rate and the two products are summed to arrive at the Generation amount. The Energy Charge is the sum of the Delivery Service amount and the Generation amount.

For each billing period, SCE determines the portion of total kWhs supplied by SCE’s URG and by the DWR. This determination is made by averaging the daily percentages of energy supplied to SCE’s Bundled Service Customers by SCE’s URG and by the DWR.

Bundled Service Customers receive Delivery Service from SCE and receive supply (Gen) service from both SCE’s URG and the DWR. The customer’s bill is the sum of the charges for Delivery Service and Gen determined, as described in this Special Condition, and subject to applicable discounts or adjustments provided under SCE’s tariff schedules.

(Continued)

Schedule TOU-8-CPP — Sheet 11

TIME-OF-USE-GENERAL SERVICE-LARGE
CRITICAL PEAK PRICING-VOLUMETRIC CHARGE DISCOUNT-VCD
(Continued)

SPECIAL CONDITIONS (Continued)

23. Customers with Service Metered and Delivered at Voltages above 50 kV (Sub-transmission customers) Included in Rotating Outages.

Sub-transmission customers, except for those customers exempt from rotating outages, are to be included in controlled, rotating outages when required by the Independent System Operator (ISO) and/or SCE. To the extent feasible, SCE will coordinate rotating outages (T) applicable to Sub-transmission customers who are fossil fuel producers and pipeline operators and users to minimize disruption to public health and safety. SCE shall not include a Sub-transmission customer in an applicable rotating outage group if the customer's inclusion would jeopardize electric system integrity. Sub-transmission customers who are not exempt from rotating outages, and seek such exemption, may submit an Optional Binding Mandatory Curtailment (OBMC) Plan to SCE in accordance with Schedule OBMC. If SCE approves a customer's OBMC Plan, the customer will become exempt from rotating outages and will be subject to the terms and conditions of Schedule OBMC and its associated contract.

Non-exempt Sub-transmission customers shall be required to drop their entire electrical load during applicable rotating outages by either (1) implementing the load reduction on their own initiative, in accordance with subsection a, below; or (2) having SCE implement the load reduction through remote-controlled load drop equipment (control equipment) in accordance with subsection b, below. A Sub-transmission customer shall normally be subject to the provisions of subsection a. If SCE approves a customer's request to have SCE implement the load reduction or if the customer does not comply with prior required load reductions, as specified in subsection c, the customer will be subject to the provisions of subsection b.

a. Customer-Implemented Load Reduction.

(i) Notification of Required Load Reduction. At the direction of the ISO or when (T) SCE otherwise determines there is a need for Rotating Outage, SCE shall (T) notify each Sub-transmission customer in an affected rotating outage group to drop its entire load. Within 30 minutes of such notification, the customer must drop its entire load. The customer shall not return the dropped load to service until 90 minutes after SCE sent the notification to the customer to drop its load, unless SCE notifies the customer that it may return its load to service prior to the expiration of the 90 minutes.

(ii) Method of Notification. SCE will notify Sub-transmission customers who are required to implement their own load reduction via telephone, by either an automated calling system or a manual call to a business telephone number or cellular phone number designated by the customer. The designated telephone number will be used for the sole purpose of receiving SCE's rotating outage notification and must be available to receive the notification at all times. When SCE sends the notification to the designated telephone number the customer is responsible for dropping its entire load in accordance with subsection a. (i), above. The customer is responsible for informing SCE, in writing, of the telephone number and contact name for purposes of receiving the notification of a rotating outage.

(Continued)

Schedule TOU-8-CPP Sheet 12
TIME-OF-USE-GENERAL SERVICE-LARGE
CRITICAL PEAK PRICING-VOLUMETRIC CHARGE DISCOUNT-VCD
(Continued)

SPECIAL CONDITIONS (Continued)

23. Customers with Service Metered and Delivered at Voltages above 50 kV (Sub-transmission customers) Included in Rotating Outages. (Continued) (T)

a. Customer-Implemented Load Reduction. (Continued)

(iii) Excess Energy Charges. If a Sub-transmission customer fails to drop its entire load within 30 minutes of notification by SCE, and/or fails to maintain the entire load drop until 90 minutes after the time notification was sent to the customer, unless SCE otherwise notified the customer that it may return its load to service earlier in accordance with subsection a. (i) above, SCE shall assess Excess Energy Charges of $6 per kWh for all kWh usage in excess of the Authorized Residual Ancillary Load. Such charges will be based on the total kWh usage during the applicable rotating outage penalty period, less the product of Authorized Residual Ancillary Load in kW and the applicable rotating outage penalty period in hours. Excess Energy Charges will be determined and applied by SCE subsequent to the Sub-transmission customer's regularly scheduled meter read date following the applicable rotating outage.

For customers with net-generators, Excess Energy Charges shall not apply during periods of verifiable scheduled generator maintenance or if the customer's generator suffers a verified forced outage. The scheduled maintenance must be approved in advance by both the ISO and SCE, but approval may not be unreasonably held.

(iv) Authorized Residual Ancillary Load. Authorized Residual Ancillary Load is load that is deemed to be equivalent to five percent of the Sub-transmission customer's prior billing month's recorded Maximum Demand. This minimum load level is used as a proxy to allow for no-load transformer losses and load attributed to minimum grid parallel operation for generators connected under Rule 21.

b. SCE-Implemented Load Reduction.

Non-exempt Sub-transmission customers may request, in writing, to have SCE drop the customer's entire load during all applicable rotating outages using SCE's remote-controlled load drop equipment (control equipment). If SCE agrees to such arrangement, SCE will implement the load drop by using one of the following methods:

(i) Control Equipment Installed. For a Sub-transmission customer whose load can be dropped by SCE's existing control equipment, SCE will implement the load drop during a rotating outage applicable to the customer. The customer will not be subject to the Notification and Excess Energy Charge provisions set forth in subsection a, above.

(Continued)

Schedule TOU-8-CPP Sheet 13
TIME-OF-USE-GENERAL SERVICE-LARGE
CRITICAL PEAK PRICING-VOLUMETRIC CHARGE DISCOUNT-VCD
(Continued)

SPECIAL CONDITIONS (Continued)

23. Customers with Service Metered and Delivered at Voltages above 50 kV (Sub-transmission customers) Included in Rotating Outages. (Continued) (T)

b. SCE-Implemented Load Reduction. (Continued)

(ii) Control Equipment Pending Installation. For a Sub-transmission customer whose load can not be dropped by SCE's existing control equipment, the customer must request the installation of such equipment at the customer's expense in accordance with SCE's Rule 2, Section H, Added Facilities. Pending the installation of the control equipment, the customer will be responsible for dropping load in accordance with the provisions of subsection a, above, including the Notification and Excess Energy Charge provisions.

c. Non-compliance: A non-exempt Sub-transmission customer subject to subsection a, above, who fails to drop load during three rotating outages in a three year period to a level of at least 20% of the customer's prior billing month's recorded Maximum Demand averaged over the applicable rotating outage period, is not in compliance with this tariff. The three year period shall commence with the first failure to drop load as specified in this subsection. A customer not in compliance with this condition will be placed at the top of the Sub-transmission customer rotating outage group list and will be expected to comply with subsequent applicable rotating outages. In addition, the customer must select one of the two options below within fifteen days after receiving written notice of non-compliance from SCE. A customer failing to make a selection within the specified time frame will be subject to subsection c. (ii) below.

(i) Subject to Schedule OBMC: The customer shall submit an OBMC Plan, in accordance with Schedule OBMC, within 30 calendar days of receiving written notice of non-compliance from SCE. Pending the submittal of the OBMC Plan by the customer and pending the review and acceptance of the OBMC Plan by SCE, the customer will remain responsible for dropping load in accordance with the provisions of subsection a, above, including the Notification and Excess Energy charge provisions. If the customer fails to submit an OBMC Plan within 30 days of receiving notice of non-compliance from SCE, or if the customer's OBMC Plan is not approved by SCE, or if the customer fails to meet the requirements of Schedule OBMC once the OBMC Plan is approved, the customer shall be subject subsection c. (ii), below.

(ii) Installation of Control Equipment. The customer shall be subject to the installation of control equipment at the customer's expense in accordance with SCE's Rule 2, Section H, Added Facilities, if such equipment is not currently installed. If such switching capability is installed, SCE will drop the customer's load for all applicable subsequent rotating outages in accordance with the provisions of subsection b, above. Pending the installation of control equipment, the customer will remain responsible for dropping load in accordance with the provisions of subsection a, above, including the Notification and Excess Energy Charge provisions.

(Continued)

Schedule TOU-8-CPP Sheet 14
TIME-OF-USE-GENERAL SERVICE-LARGE
CRITICAL PEAK PRICING-VOLUMETRIC CHARGE DISCOUNT-VCD
(Continued)

SPECIAL CONDITIONS

23. Customers with Service Metered and Delivered at Voltages above 50 kV (Sub-transmission customers) Included in Rotating Outages. (Continued)

d. Net-Generators

Sub-transmission customers who are also net-generators are normally exempt from rotating outages, but they must be net suppliers of power to the grid during all rotating outages. For the purpose of this Special Condition, a net-generator is an SCE customer who operates an electric generating facility as part of its industrial or commercial process, and the generating facility normally produces more electrical power than is consumed in the industrial or commercial process, with the excess power supplied to the grid. Sub-transmission customers whose primary business purpose is to generate power are not included in this Special Condition.

(i) Notification of Rotating Outages. SCE will notify sub-transmission customers who are net-generators of all rotating outages applicable to customers within SCE's service territory. Within 30 minutes of notification, the customer must ensure it is a net supplier of power to the grid throughout the entire rotating outage period. Failure to do so will result in the customer losing its exemption from rotating outages, and the customer will be subject to Excess Energy Charges, as provided below.

(ii) Excess Energy Charges. Net generators who are not net suppliers to the grid during each rotating outage period will be subject to Excess Energy Charges of $6 per kWh for all kWh usage in excess of the Authorized Residual Ancillary Load. Such charges will be based on the total kWh usage during a rotating outage penalty period, less the product of Authorized Residual Ancillary Load in kW and the applicable rotating outage period hours. Excess Energy Charges will be determined and applied by SCE subsequent to the customer's regularly scheduled meter read date following the applicable rotating outage. Excess Energy Charges shall not apply during periods of verifiable scheduled generator maintenance or if the customer's generator suffers a verifiable forced outage. The scheduled maintenance must be approved in advance by either the ISO or SCE, but approval may not be unreasonably withheld.

INFORMATION ON SCE'S CRITICAL PEAK PRICING RATE OPTION

Lower your business' electric bills by shifting or reducing electricity during "critical peak" summer afternoons.

Southern California Edison's (SCE) Critical Peak Pricing (CPP) program may benefit customers who have at least one account with registered demands greater than 200 kilowatts (kW), and who can reduce or shift their power during the summer season on-peak (Noon to 6:00 p.m.) time period during a CPP Event. Energy rates during summer season CPP Events are approximately three to five times higher than energy rates during summer season non-CPP Events. However, customers on a CPP schedule receive reduced energy rates for all non-CPP usage during the On- and Mid-Peak time periods throughout the year.

ELIGIBILITY

SCE's CPP program will be available to most customers with demands greater than 200 kW and who rely on SCE for generation, transmission, and distribution of electric services (bundled service customers). The three CPP rate schedules are TOU-8-CPP, GS-2-TOU-CPP, and TOU-PA-CPP. Interval metering is required prior to participation and Direct Access customers are ***not*** eligible for service on any of SCE's CPP rate schedules.

Those participating in the CPP program must agree to allow the California Energy Commission (CEC), or its contracted agent, to complete any surveys or site visits for measurement and evaluations, as needed to enhance the program, as well as completing all program surveys.

GOOD CANDIDATES FOR CPP

This program may benefit medium to large businesses, as well as agricultural and water pumping customers who have the flexibility of reducing or eliminating on-peak power usage during a CPP Event.

CPP EVENTS

A CPP Event can only be activated during SCE's summer season, between Noon and 6:00 p.m., Monday through Friday, excluding holidays. Twelve (12) events will be called per summer season, each year the program is in effect. The summer season is the four months beginning at 12:00 a.m. on the first Sunday in June and continuing until 12:00 a.m. on the first Sunday in October of each calendar year.

THE CPP EVENT "TRIGGERS"

Participants will be notified when SCE determines that a CPP Event is warranted. There are a number of "triggers" that may activate a CPP Event, including high system demand and/or low generation supply, system emergency testing, high market prices, temperature registering at least 87 degrees by 2:00 p.m. (as measured at the Los Angeles Civic Center) or at SCE's discretion. SCE will adjust the temperature trigger threshold up or down, over the course of the summer season as necessary to achieve the CPP program design basis of 12 CPP Events per summer season.

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TYPES OF EQUIPMENT NEEDED

Participants must have an SCE-approved interval metering system capable of recording usage in 15-minute intervals. Those customers with multiple accounts on the same or adjacent sites may choose to have one or all of their accounts participate on an applicable CPP schedule as long as at least one of the accounts remains above 200 kW and such account is served under a CPP schedule.

NOTIFICATION

Participants will be notified via telephone call. SCE will begin notifying customers of a CPP Event prior to 3:00 p.m. two days before an event. If SCE cannot reach the customer on the first attempt, then SCE will make at least two additional notification attempts. Customers will receive notification of a CPP event on the customer's designated primary telephone number. CPP participants may opt to receive additional courtesy notifications via pager, cellular telephone, e-mail, or fax. All equipment needed to receive notification will be at the customer's expense. SCE does not guarantee actual receipt of notification. Participating customers will be responsible for all charges incurred during a CPP Event, even if the customer does not receive actual notice. SCE reserves the right to cancel a CPP Event at its discretion.

Are participants required to reduce power during a designated CPP Event?

No. However, customers will be charged a premium (three to five times their normal on-peak energy charge) for kWh usage that occurs during the hours of a CPP Event, which is from Noon to 6:00 p.m. on weekdays. The more customers can reduce their electricity usage during the higher-priced "critical peak" hours, the more likely those customers will avoid incurring high energy charges.

Do CPP rates vary?

Yes. For any kWh usage that occurs weekdays between the hours of 12:00 p.m. and 6:00 p.m. on a designated CPP day there is a higher on-peak energy charge, called the "critical peak" period charge. Within the critical peak period, there will be two higher priced time periods:

- Noon to 3:00 p.m., when customers will be charged approximately three times their normal on-peak rate (otherwise applicable tariff or OAT), and
- 3:00 p.m. to 6:00 p.m., when customers will be charged five times their normal on-peak rate (otherwise applicable tariff or OAT).

INCENTIVES

Participants on the CPP may select from two types of incentive options: Bill Protection and/or Technical Assistance. Customers may elect to receive one or both of these incentives, which will be available until December 31, 2005 while funds are available.

- **Bill Protection Incentive** The Bill Protection Incentive option provides 100 percent protection against paying energy rates greater than the CPP participant's "otherwise applicable tariff" or normal rate schedules (the rate schedule a customer transferred from, prior to taking part in the CPP program) for the first 14 consecutive months a customer participates in the CPP program. If a customer should leave the CPP program before the end of their 14-month commitment, the customer will not receive bill protection for **any** month they participated. Because the Bill Protection Incentive program ends December 31, 2005, customers must sign up by October 31, 2004 to take advantage of the bill protection option.

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Bill protection benefits are computed on a cumulative basis at the end of the bill protection period. That means that if the actual bill on the CPP rate is higher than it would have been on the customer's normal rate schedule, the customer will receive a credit on the bill following the end of the bill protection period equal to the difference between what the customer owes under the CPP rate and what the customer would have owed on their original rate. If each bill on the CPP rate is lower than each bill would have been on the customer's normal rate schedule, those savings are for the customer to keep. If the normal rate schedule charges are greater than the CPP rate charges, the customer will not receive a bill credit under the Bill Protection Incentive.

- **Technical Assistance Incentive** The Technical Assistance Incentive allows CPP participants the opportunity to earn a cash incentive for professional technical assistance that enhances their ability to respond to power reduction during CPP Events. A **cash incentive,** of up to $50 per kW, (not to exceed the cost of the engineering study), is broken into two parts. Participants will receive 50 percent, or up to $25 per kW of the incentive for potential on-peak power reductions upon certification by a CEC-approved professional engineer. To receive the remaining half of the Technical Assistance Incentive, customers will have to demonstrate that their actual power reduction is equal to at least 50 percent of their certified power reduction per CPP Event as averaged over four (4) consecutive CPP (summer) months, cumulating before October 1, 2005 or until available funds are exhausted, whichever is sooner. If the minimum level of measured power reduction does not occur, CPP participants will not receive the remainder of the incentive. The CEC also offers a free program called The Enhanced Automation Program. Customers may call 1-866-732-5591 or access information about the program via the Internet at www.ConsumerEnergyCenter.org/enhancedautomation. This program may help customers become more knowledgeable about their potential for reducing power; however, to receive the first half of the Technical Assistance Incentive, customers will still have to contact a CEC-certified engineering firm.

INCENTIVE AVAILABILITY

The Bill Protection Incentive and the Technical Assistance Incentive will be available to CPP participants from July 1, 2003 until December 31, 2005, while funds are available. Customers must sign up for the Bill Protection Incentive by October 31, 2004.

PROGRAM ELIGIBILITY

Are there other Demand Response Programs that a customer may participate in while participating in the CPP?

Yes. CPP Participants may also participate in the following Demand Response Programs: SCE's Scheduled Load Reduction Program (SLRP), the Demand Bidding Program (DBP), or the California Power Authority Demand Reserves Program (CPA-DRP). Customers will be ineligible to receive credit on SLRP, DBP, or the CPA-DRP during a CPP Event.

Are there any Demand Response Programs a customer cannot participate in while on the CPP?

CPP participants may ***not*** participate in any Interruptible Program (for example, I-6, I-6-BIP), Optional Binding Mandatory Curtailment Program (OBMC), or the Summer Discount Plan (SDP).

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FOR MORE INFORMATION

SCE has several programs available to help customers better manage their electricity costs, such as rebates, incentives, energy surveys, and payment options. If you have questions about other SCE programs, call **(800) 990-7788**.

For more information about the Critical Peak Pricing rate option, call the CPP Hotline at **(626) 302-8320**, contact your SCE representative, visit www.sce.com, or type www.sce.com/DRP to go directly to the Demand Response Programs website.

This fact sheet is meant as an aid to understanding SCE's pricing schedules. It does not replace the tariffs. Please refer to the individual rate schedule of interest for a complete listing of terms and conditions of service, which can be viewed or printed via the Internet at www.sce.com *(Regulatory Info Center).*

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SCHEDULE EECC-CPP

ELECTRIC ENERGY COMMODITY COST
CRITICAL PEAK PRICING

APPLICABILITY

The Critical Peak Pricing (CPP) schedule is an optional commodity tariff that offers customers the opportunity to manage their electric costs by either reducing load during high cost pricing periods or shifting load from high cost pricing periods to lower cost pricing periods. This schedule is available to customers served under a time-of-use (TOU) rate schedule currently receiving bundled utility service and have an annual maximum demand of 20 kW or greater. Customers who choose to take service under this schedule will continue to be subject to the terms and provisions of their otherwise applicable UDC tariff, unless superseded by conditions herein. This schedule is not available to Direct Access customers or Community Choice Aggregation (CCA).

TERRITORY

Applicable throughout the entire territory served by the Utility.

RATES

Summer

Non-CPP Operational Days	($/kWh)	
On-Peak	0.10714	I
Semi-Peak	0.05836	I
Off-Peak	0.03736	R

CPP Operational Days	($/kWh)	
CPP Period 1	1.15150	I
CPP Period 2	0.33185	I
Semi-Peak	0.05836	I
Off-Peak	0.03736	R

Winter

On-Peak	0.10714	I
Semi-Peak	0.05836	I
Off-Peak	0.03736	R

(Continued)

SCHEDULE EECC-CPP

N

ELECTRIC ENERGY COMMODITY COST N
CRITICAL PEAK PRICING N

RATES (Continued) N

Franchise Fee Differential

A Franchise Fee Differential of 5.78% will be applied to the total bills calculated under this schedule for all customers residing within the corporate limits of the City of San Diego. Such Franchise Fee Differential shall be so indicated and added as a separate item to bills rendered to such customers.

Time Periods

All time periods listed are applicable to local time. The definition of time will be based upon the date service is rendered.

Summer (May 1 – Sept 30)

	Non-CPP Operational Days	CPP Operational Days
CPP Period 1		3 p.m. – 6 p.m. Weekdays except Holidays
CPP Period 2		11 a.m. – 3 p.m. Weekdays except Holidays
On-Peak	11 a.m. – 6 p.m. Weekdays	
Semi-Peak	6 a.m. – 11 a.m. Weekdays	6 a.m. – 11 a.m. Weekdays
	6 p.m. – 10 p.m. Weekdays	6 p.m. – 10 p.m. Weekdays
Off-Peak	10 p.m. – 6 a.m. Weekdays	10 p.m. – 6 a.m. Weekdays
	Plus Weekends & Holidays	Plus Weekends & Holidays

Winter (All Other)

On-Peak	5 p.m. – 8 p.m. Weekdays
Semi-Peak	6 a.m. – 5 p.m. Weekdays
	8 p.m. – 10 p.m. Weekdays
Off-Peak	10 p.m. – 6 a.m. Weekdays
	Plus Weekends & Holidays

N

(Continued)

SCHEDULE EECC-CPP

ELECTRIC ENERGY COMMODITY COST
CRITICAL PEAK PRICING

SPECIAL CONDITIONS

1. Definitions: The definitions of principle terms used in this schedule are found either herein or in Rule 1, Definitions.

2. Metering Equipment: Customer's electric meter must be an interval data recorder with related telecommunications capability, compatible with the Utility's meter reading and telecommunications systems. If a customer meets the requirements of this tariff and does not have the correct metering equipment, the Utility will provide and install interval metering equipment and telecommunications systems at no cost to the customer. T T

3. CPP Operational Day: A CPP Operational Day shall be any day that the Utility designates by sending a notification to the customer by 3 p.m. of the previous day. A CPP Operational Day will only be called on non-holidays from Monday through Friday from May 1 through September 30. T T

4. Notification: The customer will be notified by 3 p.m. of the current day that a CPP event will be in effect for the following day. Customers will be notified of a CPP event by notice on SDG&E's website, e-mail message, or text message sent via the Internet to customer's alphanumeric pager. T

   Receipt of such notice is the responsibility of the participating customer. Utility does not guarantee the reliability of the pager system, e-mail system or Internet site by which the customer receives notification.

5. Notification Equipment: Customers, at their expense, must have access to the Internet and an e-mail address to receive notification of a CPP event. In addition, if customers request to be notified by alphanumeric pager, then customers must have, at their expense, an alphanumeric pager that is capable of receiving a text message sent via the Internet. A customer cannot participate in the CPP program until all of these requirements have been satisfied. T T

6. Program Operation: The determination of a CPP event will be based on a day-ahead forecasted temperature trigger and the actual system load. In addition, an event may also be triggered for certain special or extreme conditions described in Special Condition 7. Up to twelve (12) CPP Operational Days may be declared from May 1 through September 30. The Utility may adjust the forecast temperature trigger up or down over the course of the summer as necessary in an effort to achieve the twelve (12) event days, which may include four (4) test events. T T T T T

7. CPP Event Trigger: An event will be triggered if the forecasted temperature at Miramar Marine Corps Air Station (MCAS) is equal to or greater than 84° F and SDG&E's actual system load has reached or exceeded 3,620 MW by 2:30 p.m. The source for forecasts will be the Weather Channel web page for Miramar located at http://www.weather.com/weather/local/USCA0983. T T

   A CPP event may also be initiated as warranted by extreme system conditions such as special alerts issued by the California Independent System Operator, or under conditions of high forecasted California spot market prices or for testing/evaluation purposes.

(Continued)

SCHEDULE EECC-CPP

ELECTRIC ENERGY COMMODITY COST
CRITICAL PEAK PRICING

SPECIAL CONDITIONS (Continued)

8. Request for Service: Customers must submit a written request for service under this rate schedule including name, address and account number. Customer must have all necessary equipment in place prior to electing service to be eligible. Customer understands that the terms and conditions of Rule 12 require a minimum term of service of 12 months under this optional rate schedule. Service under this rate shall be effective beginning on the customer's next regularly scheduled meter read date.

   Furthermore, customers under this rate must agree to allow the Utility, the California Energy Commission (CEC) or its contracting agent to conduct a site visit for measurement and evaluation and to complete any surveys needed to enhance the CPP program. Customer shall provide all load data and background information, under appropriate confidentiality protections, needed to complete this evaluation. The data will also be made available to academic researchers, under appropriate confidentiality protections, to facilitate the understanding of demand response.

9. Program Term: Schedule EECC-CPP will remain open until terminated by the CPUC. Customers electing service herein must remain on this rate for 12 consecutive months. In addition, the Utility T reserves the right to terminate customer's service under this rate schedule with 30 days written notice.

10. Multiple Program Participation: A customer may take service under Schedule EECC-CPP while continuing to participate in certain other demand response programs. These other programs include the Demand Bidding Program (DBP), the California Power Authority Demand Response Program (CPA DRP), the Rolling Blackout Reduction Program (RBRP), the Base Interruptible Program (BIP) T and Optional Binding Mandatory Curtailment (OMBC) program. Customers participating in RBRP T may not provide load reductions using their back-up generation units during a CPP event. However, should a RBRP event be called during a CPP event, customers may utilize their back-up generation units as stated in the RBRP tariff, but they shall not receive RBRP incentives for such load reduction. Customers will not receive incentive payments for participating in the other demand reduction programs during CPP event days.

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11. Termination of Service: The customer may terminate service under this schedule after 12 T consecutive months and transfer to Schedule EECC upon written notice to the Utility. Such transfer T shall be effective on the customer's next regularly scheduled meter read date.

(Continued)

SCHEDULE EECC-CPP

ELECTRIC ENERGY COMMODITY COST
CRITICAL PEAK PRICING

SPECIAL CONDITIONS (Continued)

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12. Bill Protection Incentive: A customer electing the Bill Protection Incentive will not pay more for energy commodity service than they would have had they remained on Schedule EECC. This incentive is applied for the first twelve (12) months that a customer receives service under the CPP rate provided the customer takes continuous service for the entire duration of the bill protection period on an open account. Bill protection benefits will be computed on a cumulative basis at the end of the bill protection period and, if warranted, shall be rebilled on their otherwise applicable rate. T

13. Maximum Demand Charge: The recorded maximum demand on a CPP event day will be disregarded only if the recorded maximum demand for the billing period occurs during non CPP event hours. If the recorded maximum demand occurs during CPP event hours on a CPP event day, then it will not be disregarded; hence the highest recorded maximum demand for the billing period will be used to calculate the maximum demand charge. T

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(Continued)

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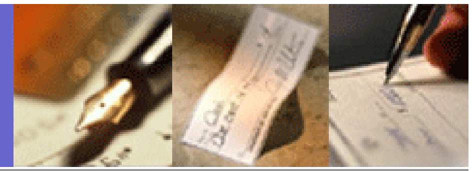
Incentives for Customized Energy-saving Projects



Critical Peak Pricing

The Critical Peak Pricing (CPP) electric rate benefits customers who can reduce electricity use during on-peak periods up to 12 days between May 1 and September 30, excluding weekends and holidays.

CPP offers a lower rate throughout the year in exchange for a higher on-peak energy charges on CPP days between the hours of 11 a.m. and 6 p.m. on weekdays.

How CPP Works
CPP event days are primarily triggered by temperature and system load, but may also be activated by extreme conditions, such as an alert by the California Independent System Operator, or for testing and evaluation purposes.

Participating customers are notified through kWickview, SDG&E’s internet based energy management tool, by 3 p.m. the business day before a CPP event day is to be called. This gives participants the opportunity to adjust their operations for the CPP event day.

SDG&E can provide a free rate analysis to help customers determine the specific benefits of CPP to their business.

Eligibility
Businesses are eligible if they meet all of the following criteria:

- Currently on a time-of-use (TOU) rate
- Have an Interval Data Recorder (IDR) meter installed
- Have a monthly average maximum demand of at least 20kW
- Purchase their electric commodity from SDG&E

Customers with special billing or metering arrangements may not qualify. Other eligibility requirements may apply, please contact us for the most recent eligibility requirements.

Additional Benefits
New enrollees on CPP are eligible for Bill Protection, which provides 100% protection against paying more on the CPP rate than you pay now under your current TOU rate for the first 12 consecutive months of program participation.

SDG&E’s Technical Assistance and Technology Incentive Program also provides assistance in determining your demand response potential and incentives for equipment that enhances your ability to respond to requests for on-peak demand reductions.
CPP participants may be eligible to participate in other demand response programs, but restrictions do apply, and participants cannot receive incentives from more than one program for the same load reduction.

For more details on Critical Peak Pricing, contact your SDG&E

Related Information

kWickview

Default CPP Rates

Contact DRP

Demand Response Overview Brochure

Energy Management Pyramid

Demand Response FAQs

Account Executive, call 866-377-4735 or email drp@semprautilities.com

Click here to view the CPP tariff.

This program is available throughout California and is offered by the state's investor owned utilities.

A2. DBP Program Materials

SCHEDULE E-DBP—DEMAND BIDDING PROGRAM

APPLICABILITY: The Schedule E-DBP Demand Bidding Program (Program) offers customers incentives for reducing energy consumption and demand when requested by Pacific Gas and Electric Company (PG&E) to increase system reliability. This Program is optional for customers with billed maximum demand of 200 kilowatts (kW) or greater during any one of the past 12 billing months and who voluntarily commit to reduce a minimum of 50 kW (T) each hour for each service account during an E-DBP Event. PG&E will determine E-DBP Bid acceptances for energy reductions. Interval metering is required to receive service under this Program. Customers must receive service on a demand Time-of-Use (TOU) electric rate schedules. Customers on Schedules AG-R, AG-V, or S are not (T) eligible for this program. A customer is not eligible to participate in this program if the revenue metering configuration is either net sale or Wholesale Transaction as specified in PG&E's Interconnection Handbook. A customer may qualify some or all of their (T) accounts for the program under the specified aggregated group provisions of this tariff. (T) This schedule is available until modified or cancelled by the California Public Utilities Commission (CPUC).

TERRITORY: This schedule applies everywhere PG&E provides electric service.

ELIGIBILITY: This schedule is available to individual PG&E bundled-service customers and Direct (T) Access customers. Each customer must take service under the provisions of their (D) otherwise-applicable rate schedule. Customers participating in the Program must be on an eligible rate schedule and commit to reduce load by at least 50 kW during a DBP (T) event. (D)

Customers on this tariff must agree to allow the California Energy Commission (CEC) or its contracting agent to conduct a site visit for measurement and evaluation, and agree to complete any surveys needed to enhance the program. Customer must submit a signed Authorization To Receive Customer Information or Act On A Customer's Behalf form giving the CEC authorization to request billing history and meter usage data information.

Customers must submit a signed Demand Response Program Agreement (T) (Form 79-976) and a Customer Agreement and Password Governing Use of Internet- (T) Based Software Agreement (Form 79-977) in order to establish service. In addition, customers must have the required metering and notification equipment in place prior to participation in this Program.

Customers who are "Essential Customers" under PG&E's Electric Emergency Plan and as defined by the Commission in Rulemaking 00-10-002, must submit to PG&E a written declaration that states that the customer is, to the best of that customer's understanding, an Essential Customer under Commission rules and exempted from rotating outages. The declaration must also state that the customer voluntarily elects to participate in this interruptible program for part or all of its load upon request by PG&E under the terms of E-DBP, while continuing to adequately meet its essential needs with backup generation or other means. In addition, an Essential Customer may commit no more than a total of 50 percent (50%) of its average peak load to all interruptible programs for each participating account.

Customers that have accounts throughout PG&E's electric service territory with (T) individual meters that have demands less than 200 kW (as described in the Applicability Section) may participate in this program under the provisions stated in the Aggregated (T) Group Section of this rate schedule. (T)

(Continued)

SCHEDULE E-DBP—DEMAND BIDDING PROGRAM
(Continued)

METERING EQUIPMENT:

Each participating customer account must have an interval meter capable of recording usage in 15-minute intervals installed that can be read remotely by PG&E. A Meter Data Management Agent (MDMA) may also read the customer's meter on behalf of the customer's Energy Service Provider (ESP) if a customer is receiving Direct Access Service. Metering equipment (including telephone line, cellular, or radio control communication device) must be in operation for at least ten (10) days prior to participating in the program to establish baseline. If required, for bundled service customers with billed maximum demand of 200 kilowatts (kW) or greater during any one (N) of the past 12 billing months, PG&E will provide and install the metering equipment at no additional cost to the customer. The installation of an internal data meter for customers taking service under the provisions or Direct Access is the responsibility of the customer's Energy Service Provider, or their Agent, and must be installed in accordance with Electric Rule 22. (N)

Customers with accounts that are less than 200 kW but greater than or equal to 50 kW (N) that are participating under the Aggregated Group provisions of this schedule may also be eligible for an internal meter at no additional cost to the customer (see Aggregated Group Section). PG&E will also provide meter data retrieval at no cost to those bundled service customers receiving free meters through this tariff until otherwise directed by the CPUC. (N)

Direct Access Service Customers – If PG&E is the Meter Data Management Agent (MDMA) on behalf of the customer's Energy Service Provider, no additional fees will be required from the Direct Access service customer. On the other hand, if the Direct Access service customer uses a third-party MDMA, the customer will be responsible for any and all costs associated with providing PG&E acceptable interval data into the PG&E system on a daily basis. This includes any additional metering or communication devices that may need to be installed, 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 to PG&E's specification on a daily basis for a period of no less than ten (10) days to establish their baseline.

NOTIFICATION EQUIPMENT:

Customers, at their expense, must have access to the Internet and an e-mail address to receive notification regarding program operations and to submit E-DBP Bids. In (T) addition, all customers must have, at their expense, an alphanumeric pager that is capable of receiving a text message sent via the Internet. A customer cannot participate in the Program until all of these requirements have been satisfied.

If an E-DBP Event occurs, customers will be notified using one or more of the above-mentioned systems. PG&E will make best efforts to notify customers, however it is the customer's responsibility to receive such notice and to check the PG&E website to see if the Program is activated. No evaluation will be performed, nor payment made, for load reductions undertaken during an E-DBP Event without such advance confirming notification. PG&E does not guarantee the reliability of the pager system, e-mail system or Internet site by which the customer receives notification.

(Continued)

SCHEDULE E-DBP–DEMAND BIDDING PROGRAM

E-DBP EVENT NOTICE:

When the forecasted system reserve margins for the next day result in the California Independent System Operator (CAISO) issuing an Alert Notice by 3:00 p.m. or when by 3:00 p.m. the CAISO day-ahead forecasted peak demand is 43,000 MW or greater, PG&E will implement a Day-Ahead E-DBP event for the following day. Day-Ahead E-DBP events will be issued for the hours between 12:00 noon and 8:00 p.m. weekdays only, excluding holidays. PG&E will notify customers of such event, and will post the hourly incentive price on the notice through the programs' web site by 3:00 p.m. the day preceding the E-DBP event. Market Price E-DBP Event Notices will be issued on Friday by 3:00 p.m. for events occurring on the following Monday, or for events that are issued for Tuesday following a holiday that falls on Monday. (N) | (N) (T) | | (T)

For the Day-Ahead E-DBP Event, participating customers shall submit bids to the program's website between 3:00 p.m. and 4:00 p.m. on the day preceding the curtailment event. After 5:00 p.m., customers will receive confirmation of bid acceptance or rejection on the web site. Unless a specific megawatt (MW) limit is requested, PG&E will deem all bids acceptable from customers. 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, the customer must reduce their kW load for each participating account to or above their accepted bid amount for each hour of their bid. 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.

(D)

(Continued)

SCHEDULE E-DBP—DEMAND BIDDING PROGRAM
(Continued)

ENERGY BID: E-DBP bidding shall be accepted for non-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 Event. 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. (D) (T) (T) (D)

E-DBP WEBSITE: Customers must submit an E-DBP Bid through PG&E's designated Internet website. Each bid submitted via the website shall be for an E-DBP Event that can take place on the next eligible day, any weekday, excluding 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 and receive information regarding this Program. 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: (T)

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

2. The customer's specific energy baseline (CSEB) is based on the hourly average of the three (3) highest energy usages on the immediate past ten (10) similar days. The three (3) highest energy usage days will be deemed as those days with the highest total kilowatt hour usages between noon and 8:00 p.m. The past ten (10) similar days will include Monday through Friday, excluding holidays, and will additionally exclude days when the customer was paid to reduce load on an interruptible or other curtailment program or days when rotating outages are called. (T) (T)

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

(Continued)

SCHEDULE E-DBP—DEMAND BIDDING PROGRAM
(Continued)

PROGRAM TESTING: PG&E may activate an E-DBP 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 $0.35/kW for qualifying load reduction during each hour of a E-DBP test event. (T) (T)

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.

(D)

Energy reduction for a given Market Price 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 only be paid for a maximum of 150 percent (150%) of their accepted bid (kW) load drop measured on an hourly basis. Participants must drop at least 50 percent (50%) of their bid load 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. (T) (T)

(D)

The 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 sum of the forecasted hourly market price of the E-DBP Event plus a participation bonus if applicable. (N)

Incentives = kW reduction x (market price + participation bonus if applicable)

Participation Bonus – The E-DBP Event participation bonus will be determined as follows:

a. When the forecasted day-ahead market price is less than or equal to $0.25/kW, the participation bonus will equal $0.10/kW for each hour of the event.

b. When the forecasted day-ahead market price is greater than $0.25/kW, but less than $0.35/kW for each hour of the event, the participation bonus will be adjusted so that the maximum total E-DBP incentive (forecasted day-ahead market price plus participation bonus) will not exceed $0.35/kW for each hour of the E-DBP event.

c. When the forecasted day-ahead market price equals or exceeds $0.35/kW for each hour of the event, the participation bonus will be zero ($0.00) and the E-DBP incentive will solely equal the forecasted day-ahead market price. (N)

(Continued)

SCHEDULE E-DBP—DEMAND BIDDING PROGRAM
(Continued)

AGGREGATED GROUP: Customers that have multiple accounts 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: (T) (D)

1. Each individual service account 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 account may change rate schedule and PG&E will provide and install an interval meter at no additional cost (N) for each individual bundled service account participating under the provisions of an aggregated group whose maximum demand is greater than or equal to 50 kW during any one of the past 12 billing months. Service accounts with an average demand that is less than 50 kW must pay for the required communicating Interval Meter prior to participation. The installation of interval meters for a Direct Access (N) customer is the responsibility of their Energy Service Provider or their agent. Fees (T) associated with a rate change will be the responsibility of the customer.

2. The customer must have at least one service account with a maximum demand of 200 kW or greater for at least one or more of the past 12 billing months within each (T) aggregated group that will be designated as the primary account for the aggregated group. A signed Demand Response Program Agreement (Form 79 976), and a (T) Customer Agreement and Password Agreement Governing use of Internet-Based Software Agreement (Form 79-977) must be submitted under the name of the primary account. The primary account will oversee all activities of the group, including event notification and the receiving of the incentive payment. It is up to (N) the lead account to determine the dispersal of the credit to the other accounts in the group. (N)

3. All service accounts 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 (T) Demand Response Program Agreement. Individual accounts, (excluding the lead account), with less than 200 kW (as described in the Applicability Section) may participate in the program as part of the aggregated group. The maximum number of accounts per aggregated group is limited to 25 accounts. Customers with more (N) (T) than 25 accounts may apply for multiple aggregated groups, provided that there is at least one account in each aggregated group meets the provisions of a primary account. PG&E at its discretion may expand the customer group limits beyond 25 accounts if it provides significant benefits to the program.

4. Accounts that are participating as an aggregated group will be exempt from the individual minimum load reduction amount. Instead accounts 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. (N)

(Continued)

SCHEDULE E-DBP—DEMAND BIDDING PROGRAM
(Continued)

AGGREGATED GROUP: (Cont'd)

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

   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 based on the hourly average of the three (3) highest energy usages days of the immediate past ten (10) similar days for all of the accounts combined. The three (3) highest energy usage days will be deemed as those days with the highest coincidental total kilowatt hour usages between noon and 8:00 p.m. for all accounts in the aggregated group. The past ten (10) similar days will include Monday through Friday, excluding holidays, and will additionally exclude days when the customer was paid to reduce load on an interruptible or other curtailment program or days when rotating outages are called.

   b. The Group's energy usage during an E-DBP event is the total coincidental load of all the accounts 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 account 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 accounts 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 accounts on the aggregated group, other than the lead account, terminates service with PG&E prior to the contract review period, the other accounts 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.

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 accounts in the pilot groups. The aggregator may, at PG&E's sole discretion, designate a lead account for the pilot group which does not meet the minimum demand requirement of 200 kW to be designated a lead account, 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 or Direct Access account 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 account 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. (T)

TECHNICAL ASSISTANCE INCENTIVES: Technical audit assistance and equipment incentives are available to enhance the customer's ability to respond to curtailment requests for on-peak demand reductions.

(Continued)

SCHEDULE E-DBP—DEMAND BIDDING PROGRAM
(Continued)

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 agreement by giving a minimum of 30 days' written notice. Cancellation of the agreement will become effective with the first regular billing cycle after the 30-day notice period. PG&E may terminate the service agreement at any time after giving a thirty (30) day written notice to participants.

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. (D)

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 (D) customers shall not participate in the California ISO's Participating Load Program (Supplemental and Ancillary Services), California Power Authority's Demand Reserves Partnership (CPA-DRP) 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.

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.

DIRECT ACCESS CUSTOMERS: Customers participating in this program and receiving service under Direct Access must notify their Energy Service Provider that they are participating in this program and when they participate in a DBP event. The per even notification must include the amount of hourly load bid for a day-ahead event or the customer's Committed Load Reduction Amount for an emergency DBP event. PG&E reserves the right to require that the Direct Access 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 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.

Pacific Gas and Electric Company®

Demand Bidding Program

The Demand Bidding Program (E-DBP) pays you an incentive to reduce your electric load according to a voluntary bid you make for a scheduled load reduction on the following non-holiday weekday. Under this program, you receive a credit equal to the product of the qualified kilowatt (kw) energy reduction for each hour a bid was accepted and the sum of the forecasted hourly market price for energy, plus a participation bonus if applicable.

How It Works

When the forecasted system reserve margins for the next day result in the California Independent System Operator (CAISO) issuing an Alert Notice or when the CAISO day-ahead forecasted peak demand is 43,000 megawatts (mw) or greater, Pacific Gas and Electric Company will request load reduction bids from customers for the following non-holiday weekday. Customers seeking to participate in the E-DBP can submit bids for a proposed level of curtailment.

Participating customers will have until 4 p.m. on the day before a proposed curtailment event to submit bids via the InterAct II Web site. Upon evaluation from Pacific Gas and Electric Company, customers will be notified of bid acceptance after 5 p.m. of the same day. Participants must bid a minimum of two consecutive hours throughout the day and must meet the minimum energy reduction threshold of 50 kilowatts (kw).

Incentives

For accepted bids, E-DBP participants will receive a credit that is equal to the product of the qualified energy reduction and the sum of the forecasted hourly market price, plus a participation bonus if applicable. Energy reduction will be determined as the difference between the Customer Specific Energy Baseline (CSEB) and the customer's actual energy usage. CSEB is determined on an hourly basis using the average energy for the three highest total energy usage days out of the 10 similar days prior to E-DBP event.

This excludes other E-DBP days:

- Days the customer was paid to reduce load
- Days when a customer was subject to a rotating outage

The participation bonus will equal to $0.10/kw for each hour and will adjust so that the maximum E-DBP incentive will not exceed $0.35/kw. When the forecasted day-ahead market price equal or exceeds $0.35/kw, the participation bonus will be zero ($0.00).

Technical Audit Assistance and Equipment Incentives will also be available to enhance the customer's ability to respond to curtailment request for on-peak demand. Details will be posted soon.

Qualifying for E-DBP

To qualify for E-DBP the customer meet all of the following requirements:

- Currently a Pacific Gas and Electric Company bundled customer
- Served under a demand time-of-use electric rate schedule(Schedule AG-V, AG-R and S are exempt from this program)
- Have billed maximum demand of 200 kw or greater for one or more of the past 12 billing months
- Not participating in the California Power Authority's Demand Reserves Partnership Program, California Independent System Operator's Participating Load Program or any other pay for performance program.

Equipment Requirements

You must have an interval meter installed and operational for 10 days prior to program participation. If required, PG&E will install the meter at no charge, assuming the customer remains in the program for 12 months.

For more information about how your business can benefit from InterAct II and our demand response programs, contact your local PG&E Account Representative or call 1 (800) 468-4743.

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Schedule DBP
DEMAND BIDDING PROGRAM
Sheet 1

APPLICABILITY

The Demand Bidding Program (DBP) is a bidding program that offers day-ahead price incentives to customers for reducing energy consumption during a DBP Event, which may be called when reserve margin forecasts for the next day result in the Independent System Operator (ISO) issuing an Alert by 3:00 p.m., or when the ISO's day-ahead forecast reaches 43,000 MW. This Schedule is optional for customers with maximum demands above 200 kW, defined herein as registered Maximum Demand of greater than 200 kW in any three months during the preceding twelve months, who are not receiving service under Real Time Pricing (RTP) rate schedules or who are not participating in the ISO's Ancillary Services Load Program or the California Power Authority's Demand Reserves Program (CPA DRP). Individual participants must commit to reduce a minimum (D) of 50 kW per hour, whereas, Aggregated Groups must commit to reduce a minimum of 200 kW per hour, during a DBP Event. The Aggregated Group provisions, as shown in the Special Condition section of this Schedule, are applicable to customers who form an Aggregated Group. An Interval Metering system, as defined in the Special Conditions section of this Schedule is required to receive service under this Schedule. Service under this Schedule is subject to meter availability.

TERRITORY

Within the entire territory served.

RATES

All other charges and provisions of the customer's otherwise applicable tariff (OAT) shall apply, except a participating customer or participating Aggregated Group, that reduces energy during a DBP Event may receive a discount in the form of a credit on its bill within 90 days of the DBP Event.

DBP Credit per kWh:

Bundled Service participants shall receive a credit equal to the day-ahead market forecast price plus 10 cents which shall not exceed 35 cents per kWh, unless the day-ahead market forecast price exceeds 35 cents per kWh, after which the total incentive paid shall be the actual day-ahead market forecast price without the adder, times the amount of actual load reduction during a DBP Event, which must be at least 50 percent of the customer's Energy Bid. Direct Access (DA) and Community Choice Aggregation Service (CCA Service) participants shall receive a credit equal to the sum of: the day-ahead market forecast price plus 10 cents which shall not exceed 35 cents per kWh minus the ISO's hourly ex-post zonal average energy price for SP 15 or; when the day-ahead market forecast price exceeds 35 cents per kWh, the total incentive paid shall be the actual day-ahead market price forecast without the adder, minus the ISO's hourly ex-post zonal average energy price for SP 15. Bundled Service Customers who participate in a day-ahead test event shall receive a DBP credit equal to 35 cents per kWh of actual load reduction, which must meet the minimum energy reduction criteria. DA and CCA Service customers who participate in a day-ahead test event shall receive a DBP credit equal to 35 cents per kWh, minus the ISO's hourly ex-post zonal average energy price for SP 15, of actual load reduction, which must meet the minimum energy reduction criteria. A DBP credit will not apply to any amount of actual load reduction that is greater than 150 percent of the customer's Energy Bid or Aggregated Group's Committed Load Reduction, whichever is applicable, and at no time will a DBP credit apply during hours that a participant's actual load reduction is less than the Minimum Energy Reduction Threshold, or Aggregated Group Minimum Load Reduction Requirements, whichever is applicable.

(Continued)

Schedule DBP Sheet 2
DEMAND BIDDING PROGRAM

(Continued)

SPECIAL CONDITIONS

1. Agreement. Participating customers and participating Aggregated Groups must sign a DBP Agreement including the Non-Disclosure Agreement and Certificate (Form 14-741). This Agreement shall become effective after SCE determines the customer has complied with the installation of the required metering equipment in accordance with the terms and conditions of the Agreement and this Schedule. (T) (T)

2. DBP Event. DBP Events may be triggered when any of the following conditions are met:

   a. ISO issued Alert: When the ISO issues an alert for the affected service territory by 3:00 p.m. on a day-ahead basis projecting that reserve margins for the next day will fall below the ISO's requirements. (T) (T)

   b. ISO Day-Ahead Forecast: When the ISO's Day-Ahead Forecast reaches 43,000 MW. (T)

   Once triggered, a DBP Event may be in effect between Noon and 8:00 p.m. Monday through Friday, excluding holidays.

3. DBP Day-Ahead Test Event. Test events may be activated by SCE no more than 2 times per year, lasting no longer than 4 hours each. Participants must meet the same requirements as those of an actual DBP Event to receive a DBP day-ahead credit.

4. Notification of DBP Events and Submission and Acceptance of Energy Bids and Aggregated Group Energy Bids. (T) (T)

   a. Notification of DBP Events. SCE will notify a customer or an Aggregated Group's Designated Lead account, whichever is applicable, of a DBP Event via SCE's notification system. SCE's primary notification method will be via telephone call, but may also include electronic mail, cellular telephone, or by fax as a courtesy. SCE will begin to notify a customer or an Aggregated Group's Designated Lead account at 3:00 p.m. the day before an event and will continue to attempt to notify a customer or an Aggregated Group's Designated Lead account two more times directly following the first notification. SCE does not guarantee customer receipt of the notification. (C)

   b. Submission of Energy Bids/Aggregated Group Energy Bids. Both individual customers and Aggregated Groups shall submit Energy Bids via SCE's designated Internet website only, no later than 4:00 p.m. on the day preceding the Event.

   c. Acceptance of Energy Bids/Aggregated Group Energy Bids. Within one hour after the bid submission deadline, SCE shall evaluate each timely submitted bid, accept or reject each bid, and notify the customer or Aggregated Group Designated Lead of the result. Bids shall be accepted for non-holiday weekdays only. Once a bid has been accepted, the bid shall not subsequently be rejected by SCE. SCE will notify customers or Aggregated Groups Designated Lead of the acceptance or rejection of bids via the DBP website. SCE does not guarantee the reliability of the Internet site by which customers or Aggregated Groups submit bids and receive information regarding this Schedule. (C) (T) (L)

(Continued)

Schedule DBP Sheet 3
DEMAND BIDDING PROGRAM

(Continued)

SPECIAL CONDITIONS (Continued)

5. Customer Site Visits: All Customers served under this Schedule automatically grant, as a stipulation of their participation on this Schedule, the California Energy Commission (CEC), or its contracted agents, the authorization to conduct site visits for measurements and evaluation purposes, as well as granting the CEC, or its contracted agents, the authorization to request and receive measurement and/or evaluation information from participating customer. Additionally, all customers served under this Schedule agree to complete all program evaluation surveys conducted by the CEC, or its contracted agents. (L)(T)

6. Direct Access Customers. Direct Access (DA) customers shall be responsible for all costs incurred by SCE when such customer uses a third party (external) Meter Data Management Agent (MDMA) and/or a third party Meter Service Provider (MSP). (N)

7. Individual Customers: This Special Condition applies to all customers except those who form an Aggregated Group. (T)

   a. Energy Bid. The amount of kW per hour (kWh usage) that a customer commits to reduce during a DBP Event is the customer's Energy Bid. The customer will be permitted to submit only one Energy Bid for a requested curtailment day, in consecutive hours, with a minimum duration of two hours. The amount of kW may vary from hour to hour within a single Energy Bid. For each DBP Event, the customer must submit its Energy Bid for a minimum energy reduction not less than 50 kW per hour in the Event. Energy Bids shall be processed for non-holiday weekdays only. In accordance with Special Condition 4.c of this Schedule, the customer can determine if its bid for an individual DBP Event was accepted by logging onto SCE's designated Internet website. (T)

   b. Customer Specific Energy Baseline (CSEB). The CSEB is used to determine the customer's Recorded Reduced Energy for each DBP Event. The CSEB will be determined by using a 10-day rolling average energy usage profile of the immediate past 10 similar days prior to the DBP Event. Then, the three highest usage days consisting of the time periods from Noon to 8:00 p.m. will be extracted from the 10 days for the CSEB. The CSEB will be calculated on an hourly basis from Noon to 8:00 p.m. using the average of the same hour for the highest three similar days. The CSEB will include Monday through Friday, excluding holidays, and will additionally exclude days when the customer was paid to reduce load on an interruptible or other curtailment program or when customers were subject to rotating outages. The CSEB will be determined by SCE at the time the customer is billed following a DBP Event. The CSEB may vary for each hour and for each Event.

(Continued)

Schedule DBP Sheet 4
DEMAND BIDDING PROGRAM

(Continued)

SPECIAL CONDITIONS (Continued)

7. Individual Customers: This Special Condition applies to all customers except those who form an Aggregated Group. (T) (T)

c. Required Metering and Internet Communication Equipment. Prior to participation on this Schedule, a customer must have Interval Metering and Internet access to SCE's designated Internet DBP website notifications. Metering equipment must be in operation for at least ten (10) weekdays (non holidays) prior to participation on this Schedule to establish a customer's Customer Specific Energy Baseline (CSEB). For participating service accounts where SCE is the MDMA and MSP, and have monthly maximum demands of 50 kW and above, who do not have the required interval metering, SCE will provide and install such equipment at no cost to the customer, subject to available funding. (T) (T) (T) | | (T)

Bundled service customers receiving an interval meter at no charge from SCE through this Program will be able to continue to use it at no additional cost even after the Program is terminated, provided that the customer remained in the Program continuously for a minimum period of one year and provided that the SCE-owned meter is, in SCE's determination, still operable. A customer who receives an interval meter through this Program but later elects to leave the Program prior to the one-year anniversary date, or is terminated for cause, will reimburse SCE for all expenses associated with the installation and maintenance of the meter. (T) (T)

d. Cancellation of Energy Bid Solicitation. An Energy Bid solicitation may be cancelled any time prior to its acceptance by SCE. (T)

e. Recorded Reduced Energy. The Recorded Reduced Energy equals the difference between the customer's CSEB and the recorded kWhs of an accepted Energy Bid during a DBP Event. (T)

f. DBP Credits. A DBP Credit will only apply to the portion of Recorded Reduced Energy in any hour that falls within a +/- 50 percent bandwidth of the customer's Energy Bid. At no time will a DBP credit apply during hours a customer does not meet the Minimum Energy Reduction Threshold. (T)

g. Minimum Energy Reduction Threshold. The minimum energy reduction must be at least 50 percent of the customer's Energy Bid and greater than or equal to 50 kW. (T) (C)

(Continued)

Schedule DBP Sheet 5
DEMAND BIDDING PROGRAM

(Continued)

SPECIAL CONDITIONS (Continued)

8. Aggregated Group: This Special Condition applies to customers, including DA Customers, who have multiple service accounts having the same SCE customer number, all of which must be within SCE's service territory, who choose to form an Aggregated Group, consisting of up to 25 service accounts, for the purpose of participating in the DBP.

a. Direct Access Aggregated Groups: A Direct Access Customer can only participate in an Aggregated Group where all service accounts in the Aggregated Group are Direct Access and have the same customer number.

b. Aggregated Group Energy Bid: The amount of kW per hour (kWh usage) that an Aggregated Group commits to reduce during a DBP Event is the Aggregated Group's Energy Bid. The Aggregated Group will be permitted to submit only one Aggregated Group Energy Bid for a requested curtailment day, in consecutive hours, with a minimum duration of two hours. The amount of kW may vary from hour to hour within a single Aggregated Group Energy Bid. For each DBP Event, the Aggregated Group must submit its energy bid for a minimum reduction not less than 200 kW per hour in the Event. Aggregated Group Energy Bids shall be processed for non-holiday weekdays only. In accordance with Special Condition 4.c of this Schedule, the Aggregated Group can determine if its bid for an individual DBP Event was accepted by logging onto SCE's designated Internet website.

c. Aggregated Group Minimum Load Reduction Requirements: An Aggregated Group is required to reduce at least 50 percent of the Aggregated Group's Energy Bid and greater than or equal to 200 kW.

d. Aggregated Group Energy Baseline (AGEB): The AGEB is used to determine the Aggregated Group's Recorded Reduced Energy for each DBP Event. The AGEB will be determined by using a 10-day rolling average energy usage profile for all accounts included in the Aggregated Group for the past 10 similar days prior to the DBP Event. The three highest usage days, consisting of the time periods from Noon to 8:00 p.m. for each individual service account within an Aggregated Group, will be extracted from the 10 days. Then, the three highest usage days for each individual account, consisting of the time periods from Noon to 8:00 p.m., will be extracted from the 10 days and summed, on an hourly basis, thus producing an hourly AGEB. The AGEB, calculated on an hourly basis from Noon to 8:00 p.m., will only consist of the same hours for the highest three days within the past 10 similar days. The AGEB will include Monday through Friday, excluding holidays, and will additionally exclude days when any service account within the AGEB was paid to reduce load on an interruptible or other curtailment program or when any account within the AGEB was subject to rotating outages. The AGEB will be determined by SCE following a DBP Event. The AGEB may vary for each hour and for each Event.

(Continued)

SPECIAL CONDITIONS (Continued)

9. Relationship to Other Interruptible/Curtailment Programs. A customer or Aggregated Group customer, currently taking service under the California Power Authority Demand Reserves Partnership Program (CPA DRP), is not eligible to receive service under this Schedule. A customer or Aggregated Group customer currently taking service under a Critical Peak Pricing (CPP) schedule, Schedule I-6, Schedule TOU-BIP, Schedule AP-I, Schedule OBMC, may be eligible for this program. However, under no circumstances will a customer or Aggregated Group customer taking service under this Schedule concurrently with any of the forementioned applicable Schedules/Programs receive more than one incentive payment for the same interrupted/curtailed load. Should either the ISO or SCE activate a CPP Event, or a notice of Interruption on an Interruptible Schedule for which a DBP customer or Aggregated Group customer participates on, as set forth in the provisions of the applicable rate schedules, during any period that overlaps with the period of a DBP Event under this Schedule, no credits under this Schedule will apply during the period of overlap and all provisions of a customer's or Aggregated Group customer's CPP Schedule, or Interruptible Schedule shall prevail. For the duration of this Schedule, a customer or Aggregated Group customer enrolled in this program shall not participate in any ISO Ancillary Services Load Program or pay for performance program.

10. Customer-Owned Electrical Generating Facilities. 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.

    a. Where customer-owned electrical generating facilities are used to meet a part or all of the customer's electrical requirements, service shall be provided concurrently under the terms and conditions of Schedule S and this Schedule. Parallel operation of such generating facilities with SCE's electrical system is permitted. A Generation Agreement is required for such operation.

    b. Customer-owned electrical generating facilities used solely for auxiliary, emergency, or standby purposes (auxiliary/emergency generating facilities) to serve the customer's load during a period when SCE's service is unavailable and when such load is isolated from the service of SCE are not subject to Schedule S. However, upon approval by SCE, momentary parallel operation may be permitted in order for the customer to avoid interruption of load during a DBP Event or to allow the customer to test the auxiliary/emergency generating facilities. A Momentary Parallel Generation Contract is required for this type of service.

11. Failure to Reduce Energy. No penalties will be assessed under this Schedule if a customer or Aggregated Group fails to comply to reduce energy during a DBP Event.

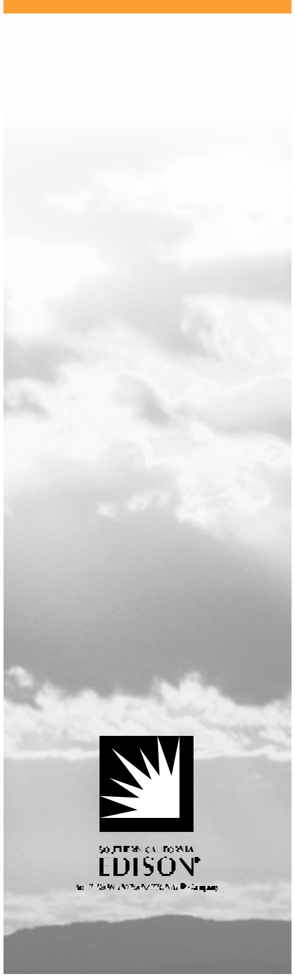
(D)

(Continued)

INFORMATION ABOUT SCE'S DEMAND BIDDING PROGRAM (DBP)

Receive credit for reducing electricity usage by participating in a Web-based bidding program.

The Demand Bidding Program (DBP) is a flexible Internet-based bidding program that offers qualified Southern California Edison (SCE) customers the opportunity to receive a credit on their bill for voluntarily reducing power (when a DBP event is called on a "day-ahead" basis) without incurring any financial penalty. By participating in this program, customers can also assist in alleviating power shortages in California as well as lower their operating costs.



ELIGIBILITY

The DBP is available to both SCE Bundled Service and Direct Access customers who have at least one service account with a demand greater than 200 kilowatts (kW).

To participate in the DBP, customers must have a communicating interval meter capable of recording in 15-minute increments. Internet access at the customer's expense is required for bidding.

Real Time Pricing Schedule, Schedule S (Standby) and California Demand Reserves Partnership (Cal-DRP) customers are not eligible for the DBP.

GOOD CANDIDATES FOR DBP

DBP customers should be able to reduce usage of electricity not critical to their main operations or processes on days when a DBP event is activated, which could be from the hours of noon to 8:00 p.m., Monday through Friday, excluding holidays.

FINANCIAL CREDIT FOR PARTICIPATION IN THE DBP

SCE may activate a DBP event on a "day-ahead" basis by 3:00 p.m. when the California Independent System Operator (CAISO) forecasts a system load peak of 43,000 megawatts (MW) for the next day, or issues a "System Alert" for the next day.

- SCE Bundled Service customers may be eligible to receive a bill credit equal to the forecasted hourly market price of power plus $0.10 per kilowatt-hour (kWh) for reducing power during a DBP event.
- Direct Access customers may be eligible to receive a bill credit equal to the sum of the day-ahead forecast price plus $0.10, minus the CAISO's hourly ex-post zonal average energy price for SP 15.
- A participating Bundled Service customer may receive a credit of $0.35 per kWh of actual power reduction during a DBP test event, while a Direct Access customer may receive the same test event credit, minus the CAISO's hourly ex-post zonal average energy price for SP 15.

DBP credits are capped at $0.35 per kWh, unless the price of power actually exceeds $0.35, after which Bundled Service participants will receive the market price and Direct Access customers will receive the market price minus the hourly ex-post zonal average energy price for SP 15.

No credits will be paid for an amount of actual load reduction that is greater than 150% or less than 50% of the customer's energy bid.

BIDDING DETAILS

A DBP event may occur any weekday (excluding holidays) between the hours of noon and 8:00 p.m. based on the trigger criteria. Customer bids for power reductions are accepted the day before the actual DBP event.

Customers may vary their energy bid commitment by hour for each DBP event. However, a customer must bid in at least two consecutive hours for an event, and may place only one energy bid per event day, via SCE's designated Internet Web site. Applicable credits will appear on customer bills after the meter has been read and DBP credits have been calculated.

The minimum bid/minimum load reduction required to participate is 50 kW per hour for an individual service account participant with a demand over 200 kW.

Customers may also combine up to 25 service accounts to form an aggregated group, which must bid a combined minimum demand of at least 200 kW per hour. Each aggregated group must assign a Designated Lead Account (DLA) that has a demand greater than 200 kW. The DLA will be the primary contact for DBP event notifications and the recipient of all DBP credits applicable to the aggregated group.

HOW TO SUBMIT A BID THROUGH THE WEB SITE TO REDUCE POWER

DBP participants must submit bid commitments to reduce power via the Internet, at SCE's EnergyManager℠ Web site. Customers will need a user ID and password to access the Web site. Once SCE has received a signed DBP Agreement, Non-Disclosure Agreement and Non-Disclosure Certificate(s), a user ID and password will be supplied to enable customers to log onto the Web site.

DBP participants may log on directly to the Web site at www.sceenergymanager.com or type www.sce.com/drp to go to the Demand Bidding Program under the "Demand Response Programs" section of SCE's Web site.

To place a DBP bid, customers must log onto the SCE EnergyManager Web site between 3:00 p.m. and 4:00 p.m. the day before a DBP event and place their kWh reduction bid for each hour of the event. If SCE does not designate a different time, the default period for an event will be from noon to 8:00 p.m. Customers may log back onto the Web site after 5:00 p.m. the day before the event to see if their bid was accepted. If customers can "view" the event, then their bid was accepted.

For questions regarding the Web site and how to bid, contact your account representative, call (626) 302-8320 or e-mail SCE at drp@sce.com.

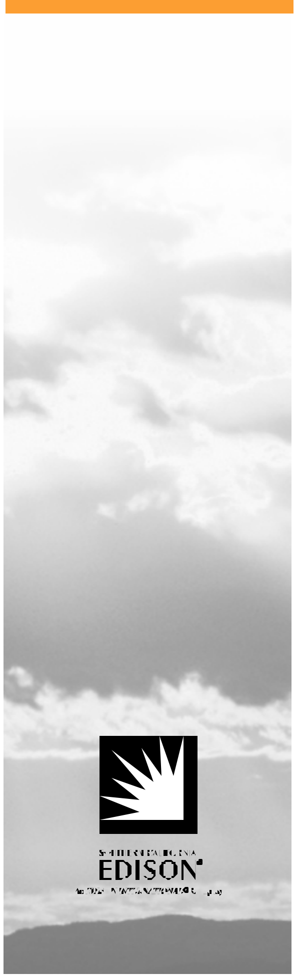
When will a customer become eligible to begin submitting commitments to reduce power?

Once SCE receives a signed DBP Agreement, including the Non-Disclosure Agreement and the Non-Disclosure Certificate(s), from an eligible customer, the Agreement will be submitted for authorization and approval. The required communicating metering equipment must be installed with at least 10 days of usage history prior to the DBP Agreement becoming effective.

Customers will receive a DBP user ID and password after all enrollment obligations and requirements have been satisfied.

CUSTOMER SPECIFIC ENERGY BASELINE (CSEB) AND AGGREGATED GROUP ENERGY BASELINE (AGEB)

For SCE to determine how much energy each customer actually reduces in each hour of a DBP event, SCE must compare the load reduction to the Customer Specific Energy Baseline (CSEB) or the Aggregated Group Energy Baseline (AGEB), whichever is applicable.



SCE will use the "10-Day Rolling Average" energy usage methodology to calculate participants' CSEB or AGEB. The CSEB or AGEB is determined on an hourly basis using the average energy usage for the three highest energy usage days of the immediate past 10 business days prior to a DBP event, with the following exclusions: holidays, other DBP days, days the customer was paid to reduce power under another program, or days when a customer was subject to a rotating outage.

Once determined, the CSEB or AGEB is used in the hourly calculation that determines the applicability of DBP credits and, if applicable, the amount of the credits.

How is the credit calculated?

The credit calculation is determined by measuring the difference between the participant's CSEB or AGEB for each DBP hour and the participant's actual energy usage for that hour. If the minimum hourly load reduction is achieved, then the actual energy reduction is multiplied by the specified price for that DBP event for each hour of the event.

DBP participants may receive a credit on their bill if they meet at least the minimum reduction requirement (50 kW for an individual account and 200 kW for an aggregated group), and reduce their load between 50% and 150% of their committed power reduction. These requirements are applicable each hour of a DBP event.

What if customers do not reduce power to their committed reduction amount or reduce more or less than their committed power reduction amount?

If a customer reduces less than 50% of its committed power reduction, the customer will not receive a credit during that hour.

DBP participants are eligible for credits for reductions from 50% to 150% of their committed power reduction amount. Participants will not receive credits for any power reductions greater than 150% of their committed electricity amount or reductions of less than the minimum reduction requirements. These thresholds are measured each hour of a DBP event.

What if a customer submits a commitment and does not reduce power during a DBP event?

There are no penalties for submitting a commitment and not reducing power.

TYPES OF EQUIPMENT NEEDED

Customers must have an SCE-approved communicating interval metering system capable of recording usage in 15-minute intervals, as well as Internet access to bid and review the status of DBP events.

A communicating interval meter will be provided and installed by SCE, at no expense to the customer, for service accounts that have demands greater than 200 kW. Most DBP participants with demands ranging from 50 kW to 200 kW may be eligible for a free interval meter on a first-come, first-served basis until available funds are exhausted.

If customers want to include service accounts with demands less than 50 kW in an aggregated group, the under-50 kW customers must provide metering acceptable to SCE at the customers' own expense. Direct Access customers who use a third-party (external) Meter Data Management Agent and/or a third-party Meter Service Provider are responsible for costs related to delivery of meter data to SCE.

Customers also need Internet access to submit their power reduction commitments. Customers should contact their SCE account representative or call (626) 302-8320 for details on obtaining access to SCE's Web site for DBP bidding.

NOTIFICATION

SCE will notify customers of a DBP event via their designated primary telephone line. SCE will begin notifying customers by 3:00 p.m. the day before a DBP event. If SCE does not reach the customer, SCE will make two more attempts, directly following the first attempt, on the designated primary telephone line. The Designated Lead Account of an aggregated group will receive all notifications for the whole group. SCE cannot and does not guarantee customer receipt of any notification.

Participants also may opt to receive courtesy notifications via alphanumeric pager, cellular telephone, e-mail or by fax. All equipment needed to receive notifications is at the customer's expense. Participating customers are responsible for all charges incurred during a DBP event, even if they do not receive actual notice.

CONTRACTUAL REQUIREMENTS

An executed DBP Agreement is mandatory prior to participation in this program. Customers also must sign the Non-Disclosure Agreement and Non-Disclosure Certificate(s). Customers should contact their SCE account representative or call (626) 302-8320 for a copy of the DBP Agreement and other materials.

Customers participating in the DBP automatically grant the California Energy Commission, or its contracting agent, permission to conduct a site visit for measurement and evaluation of the program and agree to complete any evaluation surveys needed to enhance the program.

What other Demand Response Programs may a customer take part in while participating in the DBP?

Other applicable Demand Response Programs include interruptible programs (for example, I-6 and TOU-BIP), Critical Peak Pricing (CPP) and the Summer Discount Plan.

Customers on Real Time Pricing or Schedule S (Standby) pricing schedules are not eligible for the DBP. Customers participating in CAISO Ancillary Services or Demand Relief Programs, or in the Cal-DRP, also are not eligible for the DBP.

What happens when a DBP event and a CPP event, or the I-6 program, are activated at the same time?

If both a DBP and a CPP event are called for the same day, DBP customers cannot bid on the DBP event. For an I-6 interruption, customers participating in both I-6 and DBP are not eligible for DBP credits during periods of overlap with the I-6 event. Overall, the CPP or the I-6 program takes precedence over the DBP.

FOR MORE INFORMATION

SCE has several programs available to help customers better manage their electricity costs, including rebates, incentives, energy surveys and payment options. For questions about SCE programs, call **(800) 990-7788**.

For more information about the DBP, contact your **SCE account representative**, call the DBP Hotline at **(626) 302-8320**, visit **www.sce.com**, or type in **www.sce.com/drp** to go directly to SCE's Demand Response Programs Web site.

This fact sheet is meant to be an aid to understanding SCE's pricing schedules. It does not replace information contained in the tariffs. Please refer to the individual rate schedule of interest for a complete listing of terms and conditions of service, which can be viewed online at ***www.sce.com.***

SOUTHERN CALIFORNIA EDISON

Demand Bidding Program

Questions and Answers

OVERVIEW

The Demand Bidding Program (DBP) is a flexible Internet-based bidding program that offers qualified Southern California Edison (SCE) customers the opportunity to receive a credit on their bill for voluntarily reducing power without incurring any financial penalty.

BENEFITS

Why is SCE offering this program?

The DBP is one of several Demand Response Programs SCE offers to help manage potential electricity shortages. The DBP is a voluntary program that provides you with flexibility in making power reduction commitments that can benefit you by lowering your operating costs and help reduce the possibility of power shortages in your community during times of peak power demand.

How does this program specifically benefit me?

As a participant, you may be eligible to receive a bill credit for bidding in and reducing power during a DBP event or a DBP test event. SCE also offers free audits and equipment incentives to assist you in participation and load reductions.

ELIGIBLE CUSTOMERS

Who is eligible to participate in SCE's DBP?

The DBP is open to all SCE Bundled Service and Direct Access customers who have at least one service account with an electrical demand of 200 kilowatts (kW) or greater. Customers ***ineligible*** for SCE's DBP are:

- Customers on a Real Time Pricing rate option (such as RTP-2) or the Schedule S (Standby) rate.
- Customers enrolled in the California Independent System Operator's (CAISO) Ancillary Services or Demand Relief Programs, or on the California Demand Reserves Partnership.

Am I a good candidate for the DBP?

Good candidates for the DBP are commercial, industrial or agricultural customers with the flexibility of reducing at least 50 kW per hour of electrical demand between noon and 8:00 p.m., Mondays through Fridays, excluding holidays, on days when a DBP event is activated. Customers also may combine, or aggregate, up to 25 service accounts to make a combined bid, as long as the main account (Designated Lead Account) has a demand greater than 200 kW. An aggregated group must bid a combined minimum demand of at least 200 kW per hour.

EVENT TRIGGERS

How is a DBP event triggered?

SCE may activate a DBP event on a "day-ahead" basis by 3:00 p.m. when the CAISO forecasts a system load peak of 43,000 megawatts (MW) for the next day, or issues a "System Alert" for the next day.

In addition, a DBP test event may be activated by SCE, no more than twice per calendar year. These tests, which may last no longer than four hours each, may be necessary to determine the level of response from customers who are participating in SCE's DBP.

How long will an event last?

Unless it is established prior to the event, the default duration for a DBP event will be from noon to 8:00 p.m.

BIDDING

When do these bidding event/options occur?

A DBP event may occur any weekday (excluding holidays) between the hours of noon and 8:00 p.m.

Must I commit the same bid for each hour of an event?

You do not have to commit the same bid amount for each hour of a DBP event. However, you must place a bid in at least two consecutive hours of an event. No bid can be less than 50 kW for an individual service account, or less than 200 kW for an aggregated group. You may place only one bid per event day, via SCE's designated DBP bidding Web site.

What are examples of situations in which a bid is rejected?

Two examples are: 1) if a customer only places a commitment for one hour and thus does not meet the two-hour minimum requirement, or 2) if the customer's hourly bid is less than the minimum requirement.

CREDITS

How much credit will I receive for reducing energy?

Participants in a DBP event may be eligible to receive a bill credit equal to the forecasted hourly market price for electricity plus $0.10 per kilowatt-hour (kWh) times the amount of eligible reduced load in each hour of a DBP event. Direct Access customers may be eligible to receive a bill credit equal to the sum of the day-ahead forecast price plus $0.10, minus the CAISO's hourly ex-post zonal average energy price for SP 15.

Bundled Service participants in DBP test events may be eligible to receive $0.35 per kWh for actual power reduction during a test event. Direct Access participants may be eligible to receive the same test event bill credit, minus the CAISO's hourly ex-post zonal average energy price for SP 15.

Overall, DBP credits are capped at $0.35 per kWh, unless the price of power actually exceeds $0.35, after which Bundled Service participants will receive the market price and Direct Access participants will receive the market price minus the hourly ex-post zonal average energy price for SP 15.

How are my credits calculated?

The applicable credit calculation is determined by measuring the difference between the Customer Specific Energy Baseline (CSEB) for individual participants for each DBP hour and the actual energy usage for that hour. (For aggregated groups, the calculation is based on the Aggregated Group Energy Baseline, or AGEB.)

If the minimum hourly load reduction is achieved, then the actual energy reduction is multiplied by the specified price for that DBP event for each hour of the event. You may receive a credit on your bill if you reduce at least 50%, and up to 150%, of your committed power reduction. If you reduce less than 50% of your bid amount or less than the minimum bid requirement, you will not be eligible to receive a credit for that hour of the event.

When will I receive DBP credits?

DBP credits will appear on your bill after SCE reads your meter and calculates your bill, usually within 90 days of a DBP event.

How many times during this program may I receive a credit?

CAISO system forecasts on power usage and availability determine when a DBP event is called. Thus the number of times you may participate in a year varies based on the number of times system conditions trigger a DBP event.

NOTIFICATION

How will I know if a DBP event is scheduled?

SCE will notify you of a pending DBP event via your designated primary telephone line. SCE will begin notifying you by 3:00 p.m. the day before an event. If SCE does not reach you, SCE will make two more attempts, directly following the first attempt, on the designated primary telephone line. You also may opt to receive courtesy notifications via alphanumeric pager, cellular telephone, e-mail or by fax. SCE cannot and does not guarantee your receipt of any notification.

If I do not receive notification of a pending DBP event what will happen?

There are no penalties associated with the DBP, but without bidding and reducing load to at least 50% of your committed load reduction amount, you will not be eligible for credits. As noted above, SCE does offer DBP participants the option of receiving courtesy notifications via alphanumeric pager, cellular phone, e-mail or by fax.

How do I make a change to my primary contact information?

Changes must be made in writing. To provide updated information, submit the changes in writing to your SCE account representative. If you do not have an SCE account representative, call (626) 302-8320.

Does SCE provide notification equipment?

No. All equipment necessary to receive notifications is at your expense.

SUBMITTING A POWER REDUCTION COMMITMENT (ENERGY BID)

How do I submit an energy bid to reduce power?

You must submit commitments to reduce power via the Internet, on SCE's EnergyManager[sm] Web site. You will need to sign a DBP Agreement, Non-Disclosure Agreement, Non-Disclosure Certificate(s) and other materials as required to receive a user ID and password to access the Web site. Please contact your SCE account representative or call (626) 302-8320 for details on this process.

You may log on directly to the Web site at www.sceenergymanager.com or log onto www.sce.com/drp to go to the Demand Bidding Program via the "Demand Response Programs" portion of SCE's Web site. (You also can access the DBP bidding Web site by going to www.sce.com/energymanager and clicking on the gold "Registered Users" box.)

You will be able to view the specific DBP event period on which you are bidding. For questions about the Web site, and how to bid, contact your account representative, call (626) 302-8320 or e-mail SCE at drp@sce.com.

- *To place a bid, log onto the SCE EnergyManager Web site at www.sceenergymanager.com between 3:00 p.m. and 4:00 p.m. the day before the event, and place your kW reduction bid for each hour of the DBP event. If SCE does not designate a different time, the default period for an event will be from noon to 8:00 p.m. You may log back onto the Web site after 5:00 p.m. to see if your bid was accepted. If you can "view" the event, then your bid was accepted.*

When will I become eligible to begin submitting energy bids to reduce power?

Once SCE receives a signed DBP Agreement, including the Non-Disclosure Agreement and Non-Disclosure Certificate(s), the Agreement will be submitted for authorization and approval. The required communicating metering equipment must be installed with at least 10 days of usage history prior to the DBP Agreement becoming effective. You will receive a DBP user ID and password to access the DBP Web site, allowing you to start bidding load reduction commitments, after all enrollment obligations and requirements have been satisfied.

Will I have the opportunity to adjust my energy bid(s) once I've posted them onto the Web site?

You may **NOT** change your energy bid(s) once you have posted them on the DBP Web site. Because you cannot change your energy bid(s) once you submit them, please do not bid until you are completely satisfied with your energy bid(s) and have carefully reviewed them. If you make a mistake, please contact your SCE account representative or call (626) 302-8320.

Is there a minimum or maximum amount of energy I can bid?

Yes. The minimum amount of energy you must bid is 50 kW per hour for an individual service account that has a demand greater than 200 kW, or 200 kW per hour for an aggregated group, provided that the main account (Designated Lead Account) of the group has a demand greater than 200 kW. You must submit a bid for at least two consecutive hours of an event. Energy bids that do not meet this minimum requirement will not be accepted. There is no maximum energy bid requirement, but you cannot bid more than your maximum recorded demand in the prior 12 months.

Can I submit different energy bids for each hour of a DBP event?

Yes. You may vary your bid commitment by hour for each DBP event. However, you must bid in at least two consecutive hours for each DBP event and may place only one energy bid per event day. Each hourly energy bid must meet the minimum energy bid requirement.

Can SCE cancel an energy bid solicitation?

If the CAISO notifies SCE to cancel an event, SCE may cancel its energy bid solicitation process, but only if the bid solicitation period has not expired. However, once a customer's energy bid is accepted, SCE cannot cancel the event and the customer will receive payment if the customer reduces power in an amount sufficient to qualify for payment during the DBP event.

REDUCING MORE OR LESS THAN YOUR ACCEPTED ENERGY BID AMOUNT

What if I reduce more or less than my committed power reduction amount?

If you reduce less than 50% of your committed power reduction, you will not receive a credit during that hour. You are eligible for DBP credits for reductions from 50% up to 150% of your committed amount of power reduction. You will not receive credits for any power reduced greater than 150% of your bid commitment.

What if I submit a commitment and do not reduce power during a DBP event?

There are no penalties for submitting a commitment and not reducing power.

INCENTIVES

What are the Technical Assistance and Technology Equipment Incentives?

Technical Assistance and Technology Equipment Incentives for demand response are available for professional technical assistance and the installation of approved equipment to help customers reduce power use during demand response events. These incentives no longer are program-specific. For more information on these incentives and their availability, contact your account representative or call (626) 302-8320.

THE CUSTOMER SPECIFIC ENERGY BASELINE (CSEB), AGGREGATED GROUP ENERGY BASELINE (AGEB), AND HOW THEY ARE USED TO CALCULATE 'ACTUAL' ENERGY REDUCTION

What is the Customer Specific Energy Baseline (CSEB)?

For SCE to determine how much energy each customer actually reduces in each hour of a DBP event, SCE must compare the load reduction to the Customer Specific Energy Baseline (CSEB), which is the average energy usage before the customer reduces power.

What is the Aggregated Group Energy Baseline (AGEB)?

The Aggregated Group Energy Baseline (AGEB) is the same as the Customer Specific Energy Baseline, except is it used for aggregated groups, so is based on the total usage for all of the service accounts within the aggregated group.

How is SCE able to calculate the total kW actually reduced?

SCE will use the "10-Day Rolling Average" energy usage methodology to calculate each participant's CSEB or AGEB. The CSEB and AGEB are determined on an hourly basis using the participant's average energy usage for the three highest energy usage days out of the 10 days prior to a DBP event, excluding holidays, other DBP days, days the customer was paid to reduce power, or days when a customer was subject to a rotating outage.

Once determined, the CSEB or AGEB is used in the hourly calculation that determines the applicability of DBP credits and, if applicable, the amount of the credits.

Specifically, the credit calculation is determined by measuring the difference between the participant's CSEB or AGEB for each DBP hour and the participant's actual energy usage for that hour. If the minimum hourly load reduction is achieved, then the actual energy reduction is multiplied by the specified price for that DBP event for each hour of the event.

DBP participants may receive a credit on their bill if they meet at least the minimum load reduction requirement and reduce their load between 50% and 150% of their committed power reduction. These requirements are applicable each hour of a DBP event.

ENERGY BASELINE (CSEB or AGEB)
<u>– ACTUAL ENERGY USAGE</u>
= Actual Power Reduction

METERING EQUIPMENT REQUIRED TO PARTICIPATE IN SCE'S DBP

What types of metering equipment do I need?

For participation in the DBP, you must have a communicating interval meter capable of recording usage in 15-minute intervals, and you must have Internet access. If you do not already have a communicating interval meter installed, SCE will provide and install one at no charge for each account with a demand greater than 200 kW. Most DBP participants with demands from 50-200 kW may be eligible for a free interval meter on a first-come, first-served basis until available funds are exhausted. For accounts with demands less than 50 kW, customers must purchase their own interval meter which meets SCE's requirements. Direct Access customers who use a third-party (external) Meter Data Management Agent and/or a third-party Meter Service Provider are responsible for costs related to the delivery of meter data to SCE.

CONTRACTUAL/ AGREEMENT REQUIREMENTS

Are there contractual requirements for this program?

Yes. Your SCE account representative can provide a copy of the DBP Agreement, Non-Disclosure Agreement and Non-Disclosure Certificate you need to execute to participate in this program. If you do not have an SCE account representative, call (626) 302-8320 for assistance.

Once I've completed and signed the DBP Agreement and appropriate forms, where do I send them?

Submit your original completed and signed Agreement and associated materials to your SCE account representative. If you do not have an SCE account representative, mail the completed and signed DBP Agreement and associated materials to SCE, Attn: DRP Administrator, G.O.1, Quad 1A, 2244 Walnut Grove Ave., Rosemead, CA 91770.

Once an authorized SCE management representative signs the Agreement, a copy will be returned for your records, and you then will receive a user ID and password for access to the DBP Web site.

Can I opt off the DBP at any time?

Once you have been on the DBP for 12 months, you may terminate your Agreement upon submitting a 30-day written notice to SCE. Termination of the Agreement will be effective with the first regular billing cycle after the 30-day written notice.

OTHER DEMAND RESPONSE PROGRAMS AND THE DEMAND BIDDING PROGRAM

Are there other Demand Response Programs that I may participate in while taking part in the DBP?

Yes. If eligible, you also may participate in the Large Power Interruptible Programs (i.e., I-6 and TOU-BIP), the Critical Peak Pricing (CPP) Program and the Summer Discount Plan.

What if SCE activates a DBP event and a CPP event at the same time, or a DBP event and an I-6 interruption at the same time?

If both a DBP and a CPP event are called for the same day, DBP customers cannot bid on the DBP event. For an I-6 interruption, customers participating in both I-6 and DBP are not eligible for DBP credits during periods of overlap with the I-6 event. *Overall, the CPP or the I-6 program takes precedence over the DBP.*

What if the interruption ends under I-6 before the duration of the DBP event? Will I be able to continue receiving credits under the DBP?

Yes, provided you are reducing energy in accordance with DBP requirements for the remaining duration of the DBP event.

MORE INFORMATION

How do I get more information?

SCE has several programs available to help customers better manage their electricity costs, including rebates, incentives, energy surveys and payment options. If you have questions about SCE programs, call **(800) 990-7788**.

For more information about the Demand Bidding Program, contact your **SCE account representative**, call the DBP Hotline at **(626) 302-8320**, visit **www.sce.com**, or type in **www.sce.com/drp** to go directly to SCE's Demand Response Programs Web site.

SCHEDULE DBP

DEMAND BIDDING PROGRAM

APPLICABILITY

The Demand Bidding Program (DBP) is a demand/energy bidding program that offers incentives to customers for reducing energy consumption and demand during a specific Demand Bidding Event described in the Special Conditions below. This Schedule is applicable, in combination with the customer's otherwise applicable tariff(s), on a voluntary basis to all customers, including Direct Access customers, with demands greater than 20 kW and who can commit to reduce a minimum of 10 percent of the average monthly maximum demand over the previous twelve (12) months. Customers who choose to aggregate accounts must meet a minimum load reduction requirement per event of 100 kW, as described in Special Condition 9. T T T T N N

TERRITORY

Within the entire territory served by the Utility.

RATES

DBP Incentive: Day-Ahead Forecast Price + $0.10 per kWh of Actual Demand Reduction. T
DBP Test Incentive: $0.35 per kWh of Actual Demand Reduction. T
D

Pursuant to the provisions of Special Condition 12, the DBP Incentive Payment for customers who purchase commodity from the Utility (bundled customers) is calculated by multiplying the customer's Actual Demand Reduction by the DBP Incentive for a customer's accepted bid for a Demand Bidding Event. T T

The DBP Incentive Payment for customers who purchase commodity from an Energy Service Provider (Direct Access customers) shall be calculated by the Utility deducting the corresponding California Independent System Operator (CAISO) hourly ex-post zonal average energy price for SP15 from the DBP incentive for a customers accepted bid for a Demand Bidding Event. In no case will the customer be required to pay the Utility if the ex-post price is greater than the DBP incentive. N N

The Utility will provide the DBP Incentive Payment as an adjustment to the customer's regular monthly bill, within 90 days of the Demand Bidding Event. SDG&E will make DBP Incentive Payments only for those hours of Accepted Demand Reduction, as set forth in Special Condition 12. T T T

SPECIAL CONDITIONS

1. Definitions. The definitions of terms used in this schedule are found either herein or in Rule 1.

2. Demand Bidding Event. A Demand Bidding Event occurs when either the forecasted reserve margins for the following day result in the CAISO issuing an Alert by 3:00pm, the CAISO day-ahead forecast for the state exceeds 43,000 MW, or as Utility system conditions warrant. The Utility will declare a Demand Bidding Event for the following day for a minimum of two consecutive hours between 12:00 p.m. noon and 8:00 p.m. Customers may submit a single Demand Bid per Event, indicating the amount of kW curtailment they are offering and the specific timeframe for which they will curtail. Demand Bidding Events are limited to Monday through Friday, excluding holidays. There is no limit to the number of Demand Bidding Events per month or per year. T T T T

(Continued)

SCHEDULE DBP

DEMAND BIDDING PROGRAM

SPECIAL CONDITIONS (Continued)

3. Demand Bid. A Demand Bid is the amount of kW per hour (kWh usage) that a customer commits to reduce for each hour of a Demand Bidding Event. For each hour of each Event, the customer must submit the customer's Demand Bid for a minimum demand reduction not less than 10% of the average monthly maximum demand over the previous twelve (12) months as shown in the customer's Demand Bidding Contract (Form 140-00100). Each bid must be for a minimum of two (2) hours and each bid must be for consecutive hours during the Demand Bidding Event. T D T

4. Bid Submission. Customers shall submit a Demand Bid via the Utility's designated Internet website. For Demand Bidding Events, participating customers shall submit bids to the website within one hour of notification of bid solicitation, but not later than 4:00 p.m. the day before the Demand Bidding Event. A customer Demand Bid may be submitted beyond one hour after notification of bid solicitation, but the Utility need not give equal consideration to late and timely bids. T T

5. Bid Evaluation. Unless a capacity level (megawatt quantity) is specified in the ISO notification, the Utility will deem all qualified Demand Bids received by the deadline acceptable from Customers. In evaluating late bids, the Utility will consider then-current conditions, including previous acceptance or rejection of timely bids submitted within the first hour. Bidding shall be accepted for non-holiday weekdays only. Unless a capacity level (MW quantity) is specified in the ISO or Utility event notification, the Utility will then evaluate the qualified bids received based on a first come, first served basis, taking bidder past performance and compliance into account, and accept or reject each bid. If preliminary meter data indicates that a customer is not entitled to receive compensation for the prior three consecutive Demand Bidding Events, such customer will thereafter be precluded from participating in the following two operations of the DBP. T T T T T

6. Bid Acceptance/Rejection Notification. The Utility will notify the customer of bid acceptances or rejections within one (1) hour after the bid submission deadline. Notification of bid acceptances or rejections will be sent via electronic mail (e-mail) no later than 5:00 p.m. on the day before the Demand Bidding Event. The Utility does not guarantee the reliability of the Internet site by which customers submit Demand Bids and receive information regarding this Schedule. Bid solicitations can be terminated prior to Acceptance Notification, up to the deadline of 5:00 p.m. based on ISO notification that load relief is no longer needed. T T T T

7. Expected Demand. Expected Demand (baseline) is the customer's average consumption for the three highest days for the same hour of the day over the immediately preceding 10 similar days prior to the Demand Bidding Event. The past 10 similar days will include the hours of 12 p.m. to 8 p.m. Monday through Friday, excluding holidays, and will additionally exclude days when the customer was paid to reduce load on prior Demand Bidding Event days, interruptible or other curtailment program operation days, or when rotating outages are called. Expected Demand is used to determine the customer's Actual Demand Reduction for each Demand Bidding Event. T L T T T

8. Metering Requirement. Customer's electric meter must be an interval data recorder with related telecommunications capability, compatible with the Utility's meter reading and telecommunications systems. Metering equipment must be in operation for at least 10 similar days prior to participating in the program to establish Expected Demand. The Utility may provide and install the metering equipment at no cost to the customer. T T T L

(Continued)

SPECIAL CONDITIONS (Continued)

8. Metering Requirement (Continued) T

The customer is responsible for the installation and monthly fees associated with telephone equipment and a dedicated line if such equipment is required for the remote reading or monitoring of the interval meter, unless these are provided under the terms of another program. Customers receiving an interval meter from the Utility pursuant to this rate schedule will be able to continue to use it at no additional cost even after the Program is terminated, provided that the customer remains in the Program continuously for a minimum period of one year, and submits and complies with a Demand Bid for the first ten (10) Demand Bidding Events, if bids are requested and the customer's bid is accepted. T

Non-compliance with a Demand Bidding Event occurs if the customer's Demand Bid is accepted by the Utility and the customer fails to satisfy the energy reduction requirement necessary to earn the DBP incentive. A customer who receives an interval meter through this Program but later elects to leave the Program prior to the one-year anniversary date, or does not bid and comply with a Demand Bid for the first ten (10) Demand Bidding Events, will reimburse the Utility for all expenses associated with the cost, installation and maintenance of the meter. Pursuant to Electric Rule 2, Section I, such charges will be collected as a one-time payment, and any failure to pay such charges will subject the customer to service termination pursuant to Electric Rule 11.E. If the customer would have received an interval meter at no charge as a result of another program, the customer will not be required to reimburse the Utility for these metering expenses. T T T T

For Direct Access customers, DBP compliance shall be determined from a telephone accessible electric revenue interval meter that can be read remotely by the Utility, and/or from alternative metering and telcommunications acceptable to the Utility. Direct Access customers are required to allow the Utility telecommunication access to its electric revenue meter for the purposes of determining DBP compliance. N N

9. Load Aggregations. Customers who choose to participate as a group may aggregate load to meet the group load minimum requirement of 100 kW. To qualify as a group, all participating accounts must be a minimum of 20 kW per meter. All accounts in a group must have the same Federal Tax ID Number. T T T T

a. Expected Demand. Expected Demand (baseline) for the group will be an aggregate of average consumption for the group for the three highest days for the same hour of the day over the immediately preceding 10 similar days prior to the Demand Bidding Event. The past 10 similar days will include the hours of 12 p.m. to 8 p.m. Monday through Friday, excluding holidays, and will additionally exclude days when the customer was paid to reduce load on prior Demand Bidding Event days, interruptible or other curtailment program operation days, or when rotating outages are called. Expected Demand is used to determine the customer's Actual Demand Reduction for each Demand Bidding Event. N

b. DBP Incentive. The incentive for each Demand Bidding Event will be calculated based on the groups' aggregated Actual Demand Reduction. Credits will only apply to the portion of the hourly Actual Demand Reduction that falls within a +/- 50 percent bandwidth of groups' demand bid. The group demand bid shall not be less than 100 kW per hour. Incentive will be applied as a credit to each participant's account based on a percentage of the total incentive amount, as designated by the group on the DBP Contract. N

(Continued)

SCHEDULE DBP

DEMAND BIDDING PROGRAM

SPECIAL CONDITIONS (Continued)

10. Cancellation of Demand Bidding Event. In the case where the ISO cancels its Alert or Warning or more advanced ISO Notice (Stage 1, 2 or 3 Emergency), the Utility will reject any bid that has not yet been accepted. Once a customer's Demand Bid has been accepted, the accepted bid shall not subsequently be rejected by the Utility, but payment shall continue to be based on the customer's actual performance, as measured by the Actual Demand Reduction. T

11. Actual Demand Reduction. The Actual Demand Reduction equals the difference between the customer's hourly Expected Demand and the recorded hourly kWh consumption during a DBP event. T

12. DBP Incentive Payment. The DBP Incentive for each Demand Bidding Event will be calculated based on the customer's Actual Demand Reduction. Credits will only apply to the portion of the hourly Actual Demand Reduction that falls within a +/- 50 percent bandwidth of the customer's Demand Bid. In no case will a customer receive a credit payment for a given hour if it does not meet, the minimum energy reduction threshold which shall not be less than 10 percent of the average monthly demand over the previous twelve (12) months. T T T

13. Utility Testing. Customers are required to participate in no more than two (2) tests per year of the communications and responsiveness of customers to a Demand Bidding Request. During such a test the customer shall be responsible to curtail load consistent with the rest of the terms of this Rate Schedule. Test events shall be no longer than 4 hours. The incentive paid to participants shall be the product of their demand reduction and $0.35 per kWh per test event. T T

14. Contract Requirement For Service. As a condition precedent to commencing service on this Schedule, customer shall submit to the Utility a completed Demand Bidding Program Contract (Form 140-00100) and, if acceptable to the Utility, the Utility shall sign and return the Form Contract to customer. A customer may not commence service on this Rate Schedule until the Utility has signed and returned the Form Contract to the customer. T

    Customers on this tariff must agree to allow the Utility, the California Energy Commission (CEC) or its contracting agent to conduct a site visit for measurement and evaluation, and agree to complete any surveys needed to evaluate the DBP program. Furthermore, customer shall provide all load data and background information, under appropriate confidentiality protections, needed to complete this evaluation. The data will also be made available to academic researchers, under appropriate confidentiality protections, to facilitate the understanding of demand response. D

15. Utility Reporting. Utility will provide the Commission with a monthly report on the economics of this Rate Schedule. The monthly report may contain information on individual customer performance. T

16. Termination of Schedule. Upon signing the Form Contract for Service on Schedule DBP, customer shall remain on the Rate Schedule until the Schedule is terminated or the customer submits its termination in writing to the Utility. Customers may choose to terminate the Contract at any time. Contract termination shall be effective five (5) days following Utility's receipt of customer's written termination. This Schedule is in effect until modified or terminated in the rate design phase of the Utility's next general rate case or similar proceeding. T

(Continued)

SCHEDULE DBP

DEMAND BIDDING PROGRAM

SPECIAL CONDITIONS (Continued)

17. Form of DBP Communications. The Utility will notify the customer of Demand Bid Events Acceptance or Rejection by e-mail, or other communication means specified by the Utility. Customer shall be responsible for the cost and maintenance to receive such communications and to send Demand Bids via the Internet. The Utility does not guarantee the reliability of the Internet site or e-mail system used for such communications.

18. Multiple Program Participation. A customer may participate in the DBP while taking service under Schedule EECC-CPP, Critical Peak Pricing (CPP) and Schedule 20/20-TOU (C&I Peak Day). T
Customers participating simultaneously in DBP and Schedule 20/20-TOU will not be notified of a T
DBP Event if a Schedule 20/20-TOU notification has occurred at the same time as a DBP Event T
notification occurs. Customers currently taking service under Schedule AL-TOU-CP, Base T
Interruptible Program (BIP), Scheduled Load Reduction Program (SLRP), Rolling Blackout Reduction Program (RBRP) or Optional Binding Mandatory Curtailment (OMBC) are eligible to receive service under this schedule. However, under no circumstances will a customer taking service under the above listed rate schedules and this schedule receive more than one incentive payment for the same interrupted/curtailed load. For the duration of this schedule, customers enrolled in this program shall not participate in the California Power Authority Demand Reserves Program.

19. Failure to Reduce Energy. Except as provided in Special Condition 8 of this Schedule, no additional financial penalties will be assessed under this Schedule for a customer's failure to comply or participate during a Demand Bidding Event.

20. Emergency Standby Generation Limitations. 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. Not withstanding all other applicable Utility Rules and Tariffs, customer may synchronize and operate its own standby generation in parallel with the electric system up to 60 cycles to minimize service interruption during the transfer of electric service between the Utility electric system and the customer's Emergency Standby Generation, such operation shall only occur during the period starting 15 minutes prior to and ending 15 minutes after a Demand Bidding Event defined in this Schedule. Customer must receive approval of their interconnection plans from Utility prior to operation of their generator in parallel with Utility's system. In no Event shall the customer operate its own standby generation in parallel with the Utility electric system during Utility service interruptions.

    Upon termination or expiration of the term of this Schedule or associated Form Contract, customer agrees to either 1) dismantle all equipment necessary for customer's own standby generation to synchronize and operate in parallel with the Utility electric system for the purpose of electric service transfer from the Utility electric system to the customer's own standby generation, or 2) purchase and install a generator output meter meeting Utility's standards and either comply with applicable tariffs or take service under a contract.

SDGE
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Energy Efficiency
Customer Choice
For Energy Service Providers
Economic Development
Safety
Energy Links
Renewable Energy
Events & Training

Demand Bidding Program

The Demand Bidding Program (DBP) pays you an incentive to reduce your electric load by allowing you to bid in the amount of load you can reduce for the following day. Participants in DBP receive a monthly bill credit equal to market price plus 10 cents per kilowatt-hour (kWh) for each kWh reduced during a DBP event.

How the Demand Bidding Program Works

On a Day-Ahead basis, when electric supplies are anticipated to be low, the California Independent System Operator will direct the utilities to call participants for load reductions for certain hours of the next day. Participants will bid (a) the amount of electric load they can reduce, and (b) the hours which they are willing to reduce this load. The minimum bid is 10% of average monthly maximum demand per participating meter and can vary from hour to hour within a single event. A minimum of two consecutive hours is required for a bid.

Bidding occurs Monday through Friday, excluding holidays. Events will be called between noon and 8 pm. Participants will be notified of or can verify the status of their bid by 5pm the day before the event.

Incentives are based on comparing load and usage for the same hours bid by the customer, using the three highest usage days from the ten previous days. For an incentive to be paid, a minimum reduction of 10% of average monthly maximum demand must be achieved.

Eligibility

Businesses that can reduce their electric load by a minimum of 10% of their average monthly maximum demand with a day ahead notification are eligible.

Other Benefits

SDG&E's Technical Assistance and Technology Incentive Program also provides assistance in determining your demand response potential and incentives for equipment that enhances your ability to respond to requests for on-peak demand reductions.
DBP Participants may be eligible to participate in other demand response programs, but restrictions do apply, and participants cannot receive incentives from more than one program for the same load reduction.

Demand Bidding is one of the ways that SDG&E is developing energy solutions. For more details on the Demand Bidding Program, contact your SDG&E Account Executive, call 866-377-4735 or email drp@semprautilities.com

Click here to view the DBP contract.

Click here to view the DBP tariff.

Related Information

kWickview

Default CPP Rates

Contact DRP

Demand Response Overview Brochure

Energy Management Pyramid

Demand Response FAQs

This program is available throughout California and is offered by the state's investor owned utilities.

Safety | Careers | Financial | Rates & Regulations | Privacy Policy (Effective 2004) | Site Index | Sempra Energy

A3. DRP Program Materials

STATE OF CALIFORNIA

CONSUMER POWER AND CONSERVATION FINANCING AUTHORITY

California Demand Reserves Partnership Fact Sheet

What Is the California Demand Reserves Partnership Program?

- This new government and business partnership program helps to maintain a clean, reliable, and cost-effective electricity supply in California through business demand response.
- The program encourages businesses to agree to reduce power usage when supplies are low due to weather extremes, power plant outages, or transmission system bottlenecks.
- Businesses use about half of the peak electricity load during weekday afternoon hours. Available supplies are immediately increased when businesses reduce usage or shift non-essential operations to non-peak usage times.
- Between 500 and 1,000 megawatts of power are made available – enough to keep the lights on in up to 500,000 California homes, while displacing the need to build 20 new peak power plants.
- For the very first time, advanced metering and Internet communications technologies allow businesses to provide power to California just as power plants do – and without any pollutants.
- Businesses are compensated for choosing to reduce their power usage when it is most needed.

Who Administers & Operates the Program?

- The California Power Authority (CPA) administers the program in cooperation with the California Department of Water Resources (DWR) and the California Independent System Operator (CAISO).
- APX Inc., based in Santa Clara, Calif., operates the program under a contract with the CPA.
- The following Demand Reserves Providers, under contract to the CPA, manage program participation by businesses and other organizations: Ancillary Services Coalition; DBS Industries; Infotility; Planergy; and Robertson Bryan.
- California's Flex Your Power Campaign assists the CPA in promoting the program to businesses.

When Will the Program Begin?

- This five-year program begins operation July 1, 2002.

How Does It Work?

- A business signs up to participate through a Demand Reserves Provider. The business determines the maximum amount of kilowatt reduction it can provide during high usage hours.
- The business is paid a monthly reservation fee to have capacity available.
- When the state needs additional energy via reduced usage, participating businesses are notified up to 24 hours in advance.
- The APX-operated Internet-based computer system records and monitors the reduction as it occurs and calculates the additional amount each business will be compensated for its actual reductions.
- The business receives compensation from the Demand Reserves Provider it has selected.

What Are the Benefits?

- This partnership program provides an immediate and flexible insurance policy for power grid emergencies.
- The program can help reduce price spikes caused by supply shortages.
- The electric power made available by demand response is the cleanest of all – power not used.
- The program saves up to 50 percent of the cost of building and operating peaker power plants.
- The program can help reduce price spikes caused by supply shortages.
- Businesses offset their energy costs, contributing to the state's economic health and helping to keep jobs in California.

Who Can Participate?

- California businesses, such as manufacturing plants, commercial firms, agricultural firms, stores and other retailers, and property management firms.
- Government facilities, water agencies, and universities.
- Other large full-service customers of the state's major utilities – PG&E, Southern California Edison, and San Diego Gas & Electric.

For More Information:

News Media Contact: Linda Chou, CPA, 916/651-9750, linda.chou@dgs.ca.gov

Go To: www.capowerauthority.ca.gov/ or www.caldrp.com (to be available by July 1, 2002).

Flex your POWER

California Demand Reserves Partnership:

Putting Conservation to Work.

The State of California has joined forces with businesses and organizations and a team of power transaction and demand management experts to create the nation's largest electricity demand response program.

When supplies are low, participating businesses and organizations reduce power usage in most cases by making minor adjustments that are usually invisible to customers and employees. The reductions can be scheduled and dispatched into the transmission grid when and where need, just like generation.

Businesses and organizations are paid for their participation — offsetting their operational costs and helping to keep jobs in California. And, this program saves on the cost of the new peak power plants that would otherwise be needed.

This innovative partnership helps to keep the lights on with clean and low-cost power.

California Power Authority CDWR

Operated by: APX

TO SIGN UP

- Review the participation qualifications under Sign Up.
- Contact one of the program's Demand Reserves Providers directly.
- Review our Program Policies & Procedures and Demand Reserve Providers Agreement.
- Or, complete the Online Inquiry Form to be contacted by a Demand Reserves Provider.

Overview

Creating Demand "Peaker" Units for the Reserve Power Portfolio.

Among the sources of power supply — natural gas-fired turbines, renewable sources, conservation, and demand management — that the California Power Authority (CPA) is using to create a reserve energy margin, demand management offers unique advantages. These advantages include minimal capital outlay, maximum flexibility of deployment, and the ability to lower overall market prices.

The CPA has worked with the California Department of Water Resources, and contractor APX to develop a comprehensive demand management program. The five-year California Demand Reserves Partnership program began operation July 1, 2002, to help to mitigate the effects of volatile market prices and assure adequate supplies.

Operated by APX of Santa Clara, Calif., the program enables the state to dispatch commercial and industrial power curtailment just like generation. In effect, this program creates "peaker" units, but without the pollutants, plant construction costs, and volatile fuel costs.

Businesses and organizations sign up to participate through a CPA-contracted Demand Reserves Provider, which aggregates power supplies and scheduling. (See Partners.)

With innovative meter communication software, individual and aggregated meters are monitored to ensure that usage is being reduced. The participants, in turn, can compete on an equal footing with generation in the market.

Meeting Peak Needs without High Costs or Pollutants

The benefits to California include the following.

- Fewer peaker plants will be needed, avoiding additional costs and pollutants. This program displaces the need for 20 peaker plants, saving more than $650 million in capital expenditures.
- Power "generated" through demand management reduces air pollution.
- Ratepayers and taxpayers will be spared the need to raise a large amount of capital.
- California businesses and organizations benefit from significant energy cost reduction potential, helping them to manage their operating costs and keep jobs in California.

How the Program Works

- A business or organization signs up to participate via a Demand Reserves Provider.
- The provider registers the business or organization for the program including the maximum number of kilowatts it has committed to reduce when needed.
- The California Department of Water Resources decides when and where reductions are needed due to short supplies and/or price spikes.
- The business or organization is notified by phone or e-mail as much as 24 hours in advance that a reduction will be needed.
- APX advises the state of the total amount of reduction to be available from participating California businesses and organizations.
- The business or organization makes adjustments to power usage, such as reducing lighting and adjusting thermostats, that are invisible to customers and employees in most cases. Industrial businesses may elect to reschedule certain operations to non-peak power usage time.
- The participant's Demand Reserves Provider confirms the actual amount of reduction on the program Web site.
- The Demand Reserves Provider later returns to the Web site to see the amount of compensation to pay the participant.

Quotables

"Last year California's businesses and government at all levels responded to energy shortages by conserving energy in record amounts. The state's new Demand Reserves Partnership program sustains and expands upon their successful energy reduction track record to meet the State's energy needs for the summer. This will be good for businesses and California."
— *Ex- Governor Gray Davis*

California Demand Reserves Partnership

Frequently Asked Questions

Program Sign-up & Eligibility	Participation Details
How can my company or organization join the program?	How much demand are you asking our company or city or water agency to make available?
What is the role of the Demand Reserves Providers?	Does this program only apply to peak demand?
Can you help us figure out what amount of power we can make available to the program?	How often will we be asked to draw down our demand?
Does this program require a minimum kilowatt reduction commitment?	Who will decide that our company needs to reduce its power use?
Can we participate even though we've already made significant efficiency upgrades to our facilities?	Who will physically draw down our organization's power (i.e. who turns the dial or flips the switch)?
Our organization collectively uses 200 kW at peak, but that is spread out over multiple accounts. Are we eligible for this program?	How much notice will we have before you draw down our power?
Can we participate in this program if we are already participating in another curtailment program?	Will we have control over what gets shut down at our facility?
Who are we contracting with? The state or a private company?	If we have a energy-intensive process that must be done on a reduction day, must we comply with the reduction order?
If another Demand Reserves Provider offers us a better deal after we've already signed up with one, can we switch?	Will we have any choice over when our power can be reduced?

If we don't want to participate now, can we sign up later?	What will it cost us to participate?
	How much will you pay us for energy reductions?
	Where does the money come from to pay for our demand reduction, and is the budget secure?
	How can we be sure that we will receive an accurate reimbursement for the actual amount of energy reduced?
	Are there financial penalties if we cannot provide the power when it is needed?
	Will our business competitors have access to our energy use information?
	How long is our commitment?

Program Sign-up & Eligibility

How can my company or organization join the program?

You contract with a Demand Reserves Provider. Several independent companies have been contracted by the California Power Authority (CPA) to act as Demand Reserves Providers which provide demand reduction through the businesses that have signed up through them when requested by the CAISO or the DWR. By contacting more than one Demand Reserves Provider, you can determine which provider best fits your service and financial requirements. Your Demand Reserves Provider will pay your organization based on the amount of demand reduction you provide and the terms of your contract.

What is the role of the Demand Reserves Providers?

Aggregators, or Demand Reserves Providers, are independent companies who are under contract with the CPA to deliver demand reduction through participating businesses. Their roles include:

- Recruiting businesses and organizations to participate in this program;
- Helping participants develop a strategy for reducing demand when requested;
- Informing participants when the CAISO or DWR needs demand reduction;
- Ensuring the participant has the proper metering and communication equipment so that the CAISO or DWR know how much demand has been reduced;
- Distributing payments to participants for reducing demand from the funds provided by the CPA.

The program operator APX is under contract with the CPA to provide administration, day-to-day operational support, system development, and data infrastructure services for the program.

You may be contacted by mail, telephone, or e-mail by any or all of the Demand Reserves Providers so that your organization can choose the provider it wants to use.

Can you help us figure out what amount of power we can make available to the program?
A Demand Reserves Provider can help you determine how much curtailable capacity you can make available. With extensive backgrounds in energy and demand management, the program's Demand Reserves Providers understand electricity usage profiles, facility operations, etc., and can work with you to help identify a demand reduction strategy that makes sense based on business needs.

Does this program require a minimum kilowatt reduction commitment?
This program has no minimum kilowatt reduction requirement. However, if a company or organization needs to install the required communication and metering equipment to participate in this program, that investment will be cost effective if the organization's power bill is above $200,000 annually. On the other hand, if the organization has installed or is installing intelligent communication and metering for other reasons that are not driven solely by participation in this program, then participation in this program may be cost effective for organizations that spend $50,000 or more annually for electricity.

Can we participate even though we've already made significant efficiency upgrades to our facilities?
Yes. Energy efficiency and demand reduction work hand-in-hand in helping an organization control its overall energy costs. Organizations that have installed special control equipment as part of their energy efficiency upgrades may find this program especially easy to participate in. For example, if you have installed lighting with dimmable ballasts or variable frequency drives on motors, you can easily reduce demand with little or no impact on your operational needs. However, each organization must determine the reduction strategies that best fit its business requirements. Your Demand Reserves Provider can help identify and evaluate the best-fit opportunities for your organization.

Our organization collectively uses 200 kW at peak, but that is spread out over multiple accounts. Are we eligible for this program?
Yes. You can aggregate your peak demand reduction options over several accounts. You are not required to reduce your targeted amount through just one meter.

Can we participate in this program if we are already participating in another curtailment program?
This depends upon what the other program is in which you are participating. Most of the other curtailment or demand response programs are operated by the utilities. In all cases, participation in this program and another only is permissible as long as your organization

does not "double dip" (or receive payment twice) for the same reduction.

For example, organizations that participate on the high reliability rate option, or optional binding mandatory curtailment (OBMC) may also be able to participate in the CPA program.

One of the program's Demand Reserves Providers can help you determine your eligibility to participate in more than one program.

Who are we contracting with? The state or a private company?
Participants have two choices of contracting relationship. First, your organization can act as its own Demand Reserves Provider and contract directly with the CPA if you have at least 5,000 kW of demand that can be reduced and you are comfortable in managing non-performance risk. Second, your organization can work through an independent Demand Reserves Provider that will assist you in complying with program rules, installing the correct meter and communication systems, and developing a demand reduction strategy that best fits your company's operational needs.

If another Demand Reserves Provider offers us a better deal after we've already signed up with one, can we switch?
Any "out clause" must be agreed to and included in your contract with a Demand Reserves Provider. It is advisable to consult with an attorney before signing any contract.

If we don't want to participate now, can we sign up later?
The program has an open enrollment policy. Participants may sign up at any time during the duration of the program.

Participation Details

How much demand are you asking our company or city or water agency to make available?

The amount of demand reduction (kilowatts per hour or kW/hr) depends on each organization's ability to reduce its usage or demand while balancing its production and operational requirements. You determine the amount of demand you can reduce. Obviously, the larger your organization, the more demand you can reduce.

Smaller organizations also can participate. Retail and small commercial companies with multiple sites can aggregate their demand reductions to achieve a significant amount of reduction. However, if your maximum demand is under 100 kW or your annual bill is under $50,000, your company will find it difficult to justify participating in this program, unless you have installed special metering and control equipment for other purposes.

Does this program only apply to peak demand?
Program operating hours are 11:00 a.m. to 7:00 p.m., Monday through Friday only, which is the usual peak demand time. While most reductions are anticipated to occur during peak demand periods, that may not always be the case, especially during winter months.

How often will we be asked to draw down our demand?

The frequency of reductions will depend on weather and other factors. Participating organizations make a commitment to reduce their demand up to a maximum of 24 hours per month, or a total of 150 hours per year. Once a participant has met its monthly obligation of 24 hours, it is not obligated to reduce demand for any hours remaining in that month. Participants have the flexibility to determine in ahead of time when and how much demand they can reduce each day.

Who will decide that our company needs to reduce its power use?

Either the California Independent System Operator (CAISO) or the California Department of Water Resources (DWR) will make the decision to reduce demand. The CAISO, which operates the state's system of high-voltage transmission lines, will request demand reduction if and when power supplies need to be supplemented to keep the lights on. The DWR, which is buying power for California consumers until the utilities are once again creditworthy, will request demand reduction if and when it needs to lessen the amount of power to be purchased when wholesale electricity prices are very high.

Who will physically draw down our organization's power (i.e. who turns the dial or flips the switch)?

This depends on the contract your organization has with your Demand Reserves Provider. The reduction either will be made by your internal facilities staff, control equipment at your facility that automatically responds to the reduction message, or by your Demand Reserves Provider.

How much notice will we have before you draw down our power?

Notification will be given — by 3:00 p.m. on the day before the needed reduction.

Will we have control over what gets shut down at our facility?

Each participant determines a demand reduction strategy that best suits its facility and operational needs. Once a participant has determined its normal demand reduction capability, it can decide each day if it wants to increase or decrease the amount of demand reduction they are willing to provide each hour from 11 a.m. to 7 p.m. of the next business day. However, once a participant has committed an amount of demand reduction to CPA and a reduction is called for, it must be ready to reduce this amount or it may be subject to program penalties.

If we have a energy-intensive process that must be done on a reduction day, must we comply with the reduction order?

To ensure efficient and predictable operation of this program, participants must comply with any reduction order in the amount they have committed to. If your facility has energy-intensive operations on certain days, it is best to factor that into your commitment so that it reflects what you can reasonably provide under any circumstances.

Will we have any choice over when our power can be reduced?
These choices need to be made prior to an actual demand reduction notification. In signing up for the program you are committing your company to be "on call" for reducing demand when needed between the hours of 11 a.m. and 7 p.m. The best strategy is to only commit the amount for each hour by which you are confident you can reduce your demand.

What will it cost us to participate?
Participation start-up costs depends on what type of meters are already installed at your facility.Organizations only need to have an interval meter to participate. An interval meter records electricity usage in 15-minute intervals, unlike a traditional meter that records only cumulative, monthly usage. Most end-use customers whose facility's peak demand exceeds 200 kW demand (equating to an annual bill of more than $100,000) have already received, an interval meter through the California Energy Commission. Therefore, the program start-up cost may be zero.

How much will you pay us for energy reductions?
A Demand Reserves Provider will explain the value of the program for your organization and how much you will be paid. Typically, you will receive two types of payments from your Demand Reserves Provider. One type of payment will be a retainer — you will receive a routine payment just for the committed capability to reduce demand, whether or not you actually are asked to reduce usage. The more you are willing to reduce, the higher your retainer payment. The second type will be a performance payment that is tied to the actual amount of demand you reduce.

The actual payment a participant will receive may vary by Demand Reserves Provider depending on the package of services provided.

Where does the money come from to pay for our demand reduction, and is the budget secure?
This program is funded through the DWR. The budget is secured through a contract between DWR and the CPA, which in turn has a contract with your Demand Reserves Provider. DWR funding is guaranteed by legislative action.

How can we be sure that we will receive an accurate reimbursement for the actual amount of energy reduced?
Program operator APX will review the electricity usage recorded by your meter. APX will calculate your demand reduction based on a methodology approved by the CPA and DWR. The CPA and DWR will use this calculation to determine how much is paid to your Demand Reserves Provider. In turn, your Demand Reserves Provider will pay you based on your contract terms with the provider. In the event of a question, you can ask your provider for the data APX used to calculate your demand reduction.

Are there financial penalties if we cannot provide the power when it is needed?
Because this is a market-based program, your organization may be subject to penalties in the event that you are unable to comply with your committed reduction amount. You can

manage your company's exposure to program penalties by carefully developing your demand reduction strategy and by working closely with your Demand Reserves Provider, who can adjust your reduction commitment for those times when you know that you won't be able to meet your obligation.

Will our business competitors have access to our energy use information?
All meter data is confidential and will only be shared with your Demand Reserves Provider. APX will access your meter data for account settlements, but is obligated under its contract with the CPA to ensure that your meter data remains confidential and is never shared with a business competitor. This applies to your demand profile as well.

How long is our commitment?
While this is a five-year program, that does not mean that you must commit to the full five years. You may ask your Demand Reserves Provider to provide contract terms and that allows you to sign up for a shorter term, with an option to renew. As with any contract, it is important seek legal advice to fully understand the terms and conditions you are committing to prior to signing the contract.

California Power Authority CDWR

Operated by:
APX

California Demand Reserves Partnership

Partners

California Businesses & Organizations

Program Participants

The participating businesses and organizations throughout California that have agreed to reduce their power usage when needed are the key to this innovative partnership program.

Associations

Supporting Partners

- Association of California Water Agencies
- California Business Properties Association
- California State Association of Counties
- League of California Cities
- Orange County Business Council
- Silicon Valley Manufacturing Group

California Power Authority

Program Administrator

The California Power Authority was created (SB 6X) in 2001 to provide consumers insurance against future electricity price spikes and blackouts. The Demand Reserves Partnership program meets the Power Authority's Clean Growth strategy by providing the State with clean, reliable and affordable energy.
Contact: www.capowerauthority.ca.gov/

California Department of Water Resources

Participating Agency

Contact: http://www.cers.water.ca.gov/index.html

Quotables

"The Demand Reserves Partnership allows us to reduce energy load at the most critical periods of the day when supplies are shortest and cost are typically the highest. Reducing demand can have a major impact on lowering cost while increasing system reliability."
— Pete Garris, Deputy Director, California Department of Water Resources

APX Inc.

Program Operator

APX operates the California Demand Reserves Partnership program and performs scheduling coordination for the program under contract to the CPA. An independent transaction processing agent for wholesale electric power markets, APX processes more than 500 million megawatt hours per year for approximately 200 client companies in North America. Services include trading platforms and brokerages, scheduling, clearing, settlement, and market infrastructure systems, such as generation information and demand response. A privately held company, APX has its main office in Santa Clara, California.
Contact: Rich Pon, (408) 986-2247; rpon@apx.com; caldrp@apx.com; www.apx.com.

Ancillary Services Coalition

Demand Reserves Provider

The Ancillary Services Coalition (ASC) was incorporated in 1998, building on a foundation which began in the 80s with the creation of the first non utility load shedding aggregation programs in California's history. ASC's telemetry, dispatch notification systems, account reconciliation procedures and customer service have the benefit of more than 20 years of evolution. During 2000 and 2001, ASC's customer base became the largest group in the ISO Demand Relief Program servicing many of the largest energy users statewide. ASC looks forward to qualifying new participants for the redesigned Demand Reserves Program. As we approach a true ancillary services marketplace, ASC will continue to offer flexible energy users a positive impact on their bottom lines.
Contact: Terry Rich, 714-734-3680 x17, trich@ascoalition.com

Celerity Energy

Demand Reserves Provider

Celerity is an energy management company that aggregates distributed resources, both generation and demand reduction, for use in wholesale markets to achieve locational benefits, including ancillary services and peak reductions. Celerity also provides power quality and other energy services to end use customers.
Contact: Dennis J. Quinn, dquinn@celerityenergy.com

Constellation NewEnergy

Demand Reserves Provider

Constellation NewEnergy is the #1 provider of energy supply solutions, helping our customers effectively control their energy costs. CNE combines the attributes of being a retail energy supplier, scheduling coordinator and demand reserves partnership participant with customized energy management solutions to assist clients in meeting or exceeding their energy budget objectives.

Constellation NewEnergy (http://www.newenergy.com) is a subsidiary of Constellation Energy (http://www.constellation.com) (NYSE: CEG)

Constellation Energy Earns Electric Industry's Highest Honor; Edison Award Recognizes Success in Competitive Markets

Constellation Energy Named Most Admired Energy Company in America by FORTUNE Magazine

Constellation Energy Advances to No. 167 on FORTUNE 500 List

Constellation Energy Cited as '2004 Energy Company of the Year' by Platts/BusinessWeek

Contact: Jay Purcell, Director of Business Development, (213) 996-6106 FAX (213) 576-6060, jay.purcell@constellation.com, www.newenergy.com

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Energy Logic, Inc.

Demand Reserves Provider

Energy Logic, Inc. dba C.B. Energy Logic, Inc. in the state of CA is a company of experts in the field of energy management. We have a proven history of working in partnership with our clients to develop and implement programs designed to substantially reduce energy costs. One such program is the CA Demand Reserves Program. Energy Logic has been very successful in designing, specifying and implementing Demand Response Infrastructures for national retail chains whereby all the sites can curtail loads via the web within 10 minutes of receiving a signal. Energy Logic specializes in the energy needs of retail chains and grocery store chains. Our energy consultants work with you to choose an energy saving strategy specifically targeted to meet your individual needs. As a Demand Reserve Provider in the state of CA, Energy Logic will help your company achieve to its fullest potential the benefits afforded by the

Demand Reserves Program.
Contact: Carolyn E. Banks, (508) 398-0533,
cbanks@EnergyLogicInc.com

EnerNOC, Inc.

Demand Reserves Provider

EnerNOC, Inc. is a Demand Response and Demand Side Management total solution provider operating throughout the US and abroad. Enabling customers through state of the art energy management capabilities, EnerNOC provides web-based control and management systems that allow customers to participate in cost saving and revenue-generating opportunities. EnerNOC simplifies often complicated processes by providing end-to-end implementation, from technology integration to program registration to payment reconciliation. EnerNOC provides responsive commercial contracts to allow commercial and industrial customers to generate positive cash flow immediately while the customer bears no risk for program participation. Working with utilities, independent system operators, and end users, EnerNOC provides significant benefits to all stakeholders through the innovative deployment of technology, energy market expertise, and identifying customer-specific needs.
Contact: David Brewster (617) 224-9902, dbrewster@enernoc.com, www.enernoc.com

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Excel Energy Technologies

Demand Reserves Provider

Excel Energy Technologies, Ltd. sells proprietary, energy-centric, automated energy management solutions backed by a 24/7 support center. Excel has supported energy programs in the state of California for over 10 years. Excel's unique systems were developed to function in price-driven markets and provide automated metering/monitoring, aggregation, control and curtailment capabilities. Excel's load curtailment system is capable of executing commands automatically within minutes of an ISO or other energy alert.Excel's curtailment systems are wireless, which provides ease of installation at low cost.Customers not only save high-cost energy during curtailment periods, but also have the capability necessary to participate in wholesale market activities….automatically.
Excel has been providing energy efficient solutions for clients in both the commercial and industrial business sectors since the 1980's.Our professionals have dedicated themselves to ensuring Excel remains a leader in the changing energy business environment.This creates

a win, win, win situation that is good for the client, the environment and the economy.
Contact: Ron Roller, (918) 585-5000 x34, ron.roller@excel-energy.com, www.excel-energy.com

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Infotility

Demand Reserves Provider

Infotility, Inc. has a track record of successfully providing aggregation services to both private and public sector clients for demand response programs in California. Last year, the company distributed hundreds of thousands of dollars in incentives back to its customers. Infotility also provides consulting services to organizations within the energy sector focused on information systems, marketing, program design, and customer relationship management systems. Infotility's principals and key employees have extensive experience in energy efficiency program design, information technology and distributed energy resources.
Infotility is energy infomediary that helps businesses save money by facilitating information access and commerce through the collection and dissemination of high-quality, time-sensitive information on energy supply, demand and price. As a systems integrator, the company combines data warehousing with distributed information and control technology to deliver responsive solutions for a changing energy marketplace.
The company is headquartered in Boulder, CO
Contact: David Cohen, (720) 210-1984, www.infotility.com

Onsite Energy Corporation

Demand Reserves Provider

Onsite has been providing industrial and commercial energy users with a full range of energy efficiency and generation services for more than 20 years. Since our inception, we have generated more than $200 million in incentive awards and energy savings for our customers. Our success comes from our seasoned engineering team, which takes the time understand your business model and develop solutions that work for you.

Our long standing relationships with all major state utilities and California state agencies help to insure that we can get you the highest possible incentive awards. California is a leader in the development of innovative energy incentive programs. The Demand Reserves Program is no exception. Please take the time to see what participation in DRP can do for you.

Contact: Paul Blevins, DRP Program Manager at 760-931-2400 or email at pblevins@onsitenergy.com www.onsitenergy.com

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Robertson-Bryan Inc.

Demand Reserves Provider

Robertson Bryan, Inc. (RBI) has a distinguished reputation for energy services with principal experience of more than 20 years. RBI leadership in the California power community is built on superior client services in electric load analysis, and resource planning and scheduling, all leading to reduced client power costs. As a Demand Reserves Provider for California, RBI offers client-focused perspectives to objectively assess client ability to participate in this important resource venue. Contact Robertson-Bryan for a presentation on the Demand Response Program and a frank discussion of its options for your organization.
Contact: Stuart Robertson, PE, (916) 714-1801, stuart@robertson-bryan.com, www.robertson-bryan.com

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A4. Traditional Interruptible Service Materials

COMMERCIAL/INDUSTRIAL/GENERAL
SCHEDULE E-19—MEDIUM GENERAL DEMAND-METERED TIME-OF-USE SERVICE

CONTENTS: This rate schedule is divided into the following sections:

1. APPLICABILITY: **Initial Assignment:** A customer must take service under Schedule E-19 if: (1) the customer's load does not meet the Schedule E-20 requirements, but, (2) the customer's maximum billing demand (as defined below) has exceeded 499 kilowatts for at least three consecutive months during the most recent 12-month period (referred to as Schedule E-19). If 70 percent or more of the customer's energy use is for agricultural end-uses, the customer will be served under an agricultural schedule. Schedule E-19 is not applicable to customers for whom residential service would apply, (see except for single-phase and polyphase service in common areas in a multifamily complex (see Common-Area Accounts section).

Customer accounts which fail to qualify under these requirements will be evaluated for transfer to service under a different applicable rate schedule.

(D)

The provisions of Schedule S—Standby Service Special Conditions 1 through 6 shall also apply to customers whose premises are regularly supplied in part (but <u>not</u> in whole) by electric energy from a nonutility source of supply. These customers will pay monthly reservation charges as specified under Section 1 of Schedule S, in addition to all applicable Schedule E-19 charges. Exemptions to standby charges are outlined in the Standby Applicability Section of this rate schedule.

Voluntary E-19 Service: This schedule is available on a voluntary basis for customers with maximum billing demands less than 500 kW. Customers voluntarily taking service on this schedule are subject to all the terms and conditions below, unless otherwise specified in Section 16. (T)

(Continued)

COMMERCIAL/INDUSTRIAL/GENERAL
SCHEDULE E-19—MEDIUM GENERAL DEMAND-METERED TIME-OF-USE SERVICE
(Continued)

1. APPLICABILITY: (Cont'd.)

Depending upon whether or not an Installation or Processing Charge applies, the customer will be served under one of these rates under Schedule E-19:

Rate V: Applies to customers who qualify for the voluntary provisions of this tariff and at least one of the following: (1) to customers who are served under Schedule E-19 Voluntary prior to January 1, 1996, and have not changed rate schedules since that time; or (2) to customers whose service has an existing and appropriate time-of-use meter installed and initiated service on this schedule during 1996; or (3) to customers who signed an "Incentive Program Prescriptive Performance Off-Peak Cooling Application" with PG&E prior to January 1, 1996, in order to install a thermal energy storage system and now are about to operate that system. (N)

Rate W: Applies to customers whose maximum demand is less than 200 kW and whose account does not have an appropriate time-of-use meter. The customer must pay a **"Time-Of-Use Installation Charge"** prior to taking service under this schedule. (T)

Rate X: Applies to customers whose account has an appropriate time-of-use meter, but is not currently being served under this schedule. (D) The customer will be required to pay a **"Time-Of-Use Processing Charge"** prior to taking service under this schedule. The Time-Of-Use Processing Charge will be waived for those customers who are initially required to be placed on a time-of-use schedule when their maximum demand is 200 kW or greater for three consecutive months and selects this schedule. (N)

Transfers Off of Schedule E-19: If a customer's maximum demand has failed to exceed 499 kilowatts for 12 consecutive months, PG&E will transfer that customer's account to voluntary E-19 service or to a different applicable rate schedule. After being placed on this schedule due to the 200 kW or greater provisions of this schedule, customers who fail to exceed 199 kilowatts for 12 consecutive months may elect to stay on the time-of-use provisions of this schedule or elect an applicable non-time-of-use rate schedule. (N)

Assignment of New Customers: If a customer is new and PG&E believes that the customer's maximum demand will be 500 through 999 kilowatts and that the customer should not be served under a time-of-use agricultural schedule, PG&E will serve the customer's account under Schedule E-19.

Definition of Maximum Demand: Demand will be averaged over 30-minute intervals for customers whose maximum demand exceeds 499 kW. "Maximum demand" will be the highest of all the 30-minute averages for the billing month. If the customer's use of electricity is intermittent or subject to violent fluctuations, a 5-minute or 15-minute interval may be used instead of the 30-minute interval. If the customer has any welding machines, the diversified resistance welder load, calculated in accordance with Section J of Rule 2, will be considered the maximum demand if it exceeds the maximum demand that results from averaging the demand over 30-minute intervals. The customer's maximum-peak-period demand will be the highest of all the 30-minute averages for the peak period during the billing month. (See Section 6 for a definition of "Peak-Period.") See Section 16 for the definition of maximum demand for customers voluntarily selecting E-19.

(Continued)

COMMERCIAL/INDUSTRIAL/GENERAL
SCHEDULE E-19—MEDIUM GENERAL DEMAND-METERED TIME-OF-USE SERVICE
(Continued)

1. APPLICABILITY: (Cont'd.)

Standby Demand: For customers for whom Schedule S—Standby Service Special Conditions 1 through 6 apply, standby demand is the portion of a customer's maximum demand in any month caused by nonoperation of the customer's alternate source of power, and for which a demand charge is paid under the regular service schedule.

If the customer imposes standby demand in any month, then the regular service maximum demand charge will be reduced by the applicable reservation capacity charge (see Schedule S Special Condition 1).

To qualify for the above reduction in the maximum demand charge, the customer must, within 30 days of the regular meter-read date, demonstrate to the satisfaction of PG&E the amount of standby demand in any month. This may be done by submitting to PG&E a completed Electric Standby Service Log Sheet (Form 79-726).

2. TERRITORY:

This rate schedule applies everywhere PG&E provides electricity service.

3. FIRM SERVICE RATES:

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

Customers that received the benefit of the 10 percent rate reduction prior to January 1, 2004, and who pay the Fixed Transition Amount (FTA), shall be subject to the rates set forth in Table A, which include the FTA charge and the Rate Reduction Bond Memorandum Account (RRBMA) credit. All other firm service customers taking service under this rate schedule shall be subject to the rates set forth in Table B.

(Continued)

COMMERCIAL/INDUSTRIAL/GENERAL
SCHEDULE E-19—MEDIUM GENERAL DEMAND METERED TIME-OF-USE SERVICE
(Continued)

3. Firm Service Rates: (Cont'd.)

Table A (FTA Rates)

TOTAL RATES

Total Customer/Meter Charge Rates	Secondary Voltage		Primary Voltage		Transmission Voltage	
Customer Charge Rate V ($ per meter per day)	$2.39507		$2.39507		$2.39507	
Customer Charge Rate W ($ per meter per day)	$2.25314		$2.25314		$2.25314	
Customer Charge Rate X ($ per meter per day)	$2.39507		$2.39507		$2.39507	
One-time TOU Installation Charge ($ per meter)	$443.00		$443.00		$443.00	
One-time TOU Processing Charge ($ per meter)	$87.00		$87.00		$87.00	
Optional Optimal Billing Period Service ($ per meter per month)	$130.00		$130.00		–	
Optional Meter Data Access Charge ($ per meter per day)	$0.98563		$0.98563		$0.98563	
Total Demand Rates ($ per kW)						
Maximum Peak Demand Summer	$11.93		$10.20		$6.17	
Maximum Part-Peak Demand Summer	$3.30		$2.30		$0.49	
Maximum Demand Summer	$2.73		$2.75		$0.64	
Maximum Part-Peak Demand Winter	$3.25		$2.30		$0.62	
Maximum Demand Winter	$2.73		$2.75		$0.64	
Total Energy Rates ($ per kWh)						
Peak Summer	$0.14068	(I)	$0.11805	(I)	$0.12745	(I)
Part-Peak Summer	$0.08539	|	$0.07613	|	$0.08667	|
Off-Peak Summer	$0.07294	|	$0.06864	|	$0.07841	|
Part-Peak Winter	$0.09026	|	$0.08300	|	$0.09954	|
Off-Peak Winter	$0.07276	(I)	$0.06945	(I)	$0.08259	(I)
Average Rate Limiter ($/kWh in summer months)	$0.12639		$0.12639		–	
Peak Period Rate Limiter ($/kWh in summer months)	$0.87996		$0.76443		$0.52808	

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

UNBUNDLING OF TOTAL RATES

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

Demand Rates by Components ($ per kW)	Secondary	Primary	Transmission
Generation:			
Maximum Peak Demand Summer	$5.14	$6.31	$6.17
Maximum Part-Peak Demand Summer	$1.41	$1.43	$0.49
Maximum Demand Summer	($3.55)	($2.73)	($3.78)
Maximum Part-Peak Demand Winter	$1.40	$1.43	$0.62
Maximum Demand Winter	($3.55)	($2.73)	($3.78)
Distribution:**			
Maximum Peak Demand Summer	$6.79	$3.89	$0.00
Maximum Part-Peak Demand Summer	$1.89	$0.87	$0.00
Maximum Demand Summer	$1.94	$1.14	$0.08
Maximum Part-Peak Demand Winter	$1.85	$0.87	$0.00
Maximum Demand Winter	$1.94	$1.14	$0.08
Transmission Maximum Demand*	$2.32	$2.32	$2.32
Reliability Services Maximum Demand*	$2.02	$2.02	$2.02

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

** Distribution and RRBMA charges are combined for presentation on customer bills.

(Continued)

COMMERCIAL/INDUSTRIAL/GENERAL
SCHEDULE E-19—MEDIUM GENERAL DEMAND METERED TIME-OF-USE SERVICE
(Continued)

3. Firm Service Rates: (Cont'd.)

TABLE A (FTA Rates) (Cont'd.)

UNBUNDLING OF TOTAL RATES (Cont'd.)

Energy Charges by Components ($ per kWh)	Secondary Voltage		Primary Voltage		Transmission Voltage	
Generation:						
Peak Summer	$0.10492		$0.08892		$0.09173	
Part-Peak Summer	$0.05272		$0.04764		$0.05320	
Off-Peak Summer	$0.04104		$0.04022		$0.04537	
Part-Peak Winter	$0.05698		$0.05412		$0.06442	
Off-Peak Winter	$0.04089		$0.04101		$0.04902	
Distribution:**						
Peak Summer	$0.00912		$0.00288		$0.00933	
Part-Peak Summer	$0.00603		$0.00224		$0.00708	
Off-Peak Summer	$0.00526		$0.00217		$0.00665	
Part-Peak Winter	$0.00664		$0.00263		$0.00873	
Off-Peak Winter	$0.00523		$0.00219		$0.00718	
Transmission Rate Adjustments* (all usage)	$0.00016		$0.00016		$0.00016	
Public Purpose Programs (all usage)	$0.00472		$0.00433		$0.00447	
Nuclear Decommissioning (all usage)	$0.00035		$0.00035		$0.00035	
Competition Transition Charge (all usage)	$0.00448		$0.00448		$0.00448	
Energy Cost Recovery Amount (all usage)	$0.00595	(I)	$0.00595	(I)	$0.00595	(I)
Fixed Transition Amount (all usage)	$0.00805		$0.00805		$0.00805	
Rate Reduction Bond Memorandum Account** (all usage)	($0.00166)		($0.00166)		($0.00166)	
DWR Bond (all usage)	$0.00459		$0.00459		$0.00459	

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

** Distribution and RRBMA charges are combined for presentation on customer bills.

(Continued)

COMMERCIAL/INDUSTRIAL/GENERAL
SCHEDULE E-19—MEDIUM GENERAL DEMAND-METERED TIME-OF-USE SERVICE
(Continued)

3. FIRM SERVICE RATES: (Cont'd.)

Table B (Non-FTA Rates)

TOTAL RATES

Total Customer/Meter Charge Rates	Secondary Voltage		Primary Voltage		Transmission Voltage	
Customer Charge Mandatory E-19 ($ per meter per day)	$5.74949		$4.59959		$20.04107	
Customer Charge Rate V ($ per meter per day)	$2.66119		$2.66119		$2.66119	
Customer Charge Rate W ($ per meter per day)	$2.50349		$2.50349		$2.50349	
Customer Charge Rate X ($ per meter per day)	$2.66119		$2.66119		$2.66119	
One-time TOU Installation Charge ($ per meter)	$443.00		$443.00		$443.00	
One-time TOU Processing Charge ($ per meter)	$87.00		$87.00		$87.00	
Optional Optimal Billing Period Service ($ per meter per month)	$130.00		$130.00		–	
Optional Meter Data Access Charge ($ per meter per day)	$0.98563		$0.98563		$0.98563	
Total Demand Rates ($ per kW)						
Maximum Peak Demand Summer	$13.12		$11.28		$6.85	
Maximum Part-Peak Demand Summer	$3.64		$2.54		$0.55	
Maximum Demand Summer	$3.00		$3.01		$0.67	
Maximum Part-Peak Demand Winter	$3.58		$2.54		$0.69	
Maximum Demand Winter	$3.00		$3.01		$0.67	
Total Energy Rates ($ per kWh)						
Peak Summer	$0.14974	(I)	$0.12479	(I)	$0.13646	(I)
Part-Peak Summer	$0.09175	|	$0.08160	|	$0.09376	|
Off-Peak Summer	$0.07861	|	$0.07392	|	$0.08513	|
Part-Peak Winter	$0.09714	|	$0.08922	|	$0.10803	|
Off-Peak Winter	$0.07842	(I)	$0.07483	(I)	$0.08977	(I)
Average Rate Limiter ($/kWh in summer months)	$0.14043		$0.14043		–	
Peak Period Rate Limiter ($/kWh in summer months)	$0.97773		$0.84937		$0.58676	

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

UNBUNDLING OF TOTAL RATES

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

Demand Rates by Component ($ per kW)	Secondary Voltage	Primary Voltage	Transmission Voltage
Generation:			
Maximum Peak Demand Summer	$6.33	$7.39	$6.85
Maximum Part-Peak Demand Summer	$1.75	$1.67	$0.55
Maximum Demand Summer	($3.28)	($2.47)	($3.75)
Maximum Part-Peak Demand Winter	$1.73	$1.67	$0.69
Maximum Demand Winter	($3.28)	($2.47)	($3.75)
Distribution:			
Maximum Peak Demand Summer	$6.79	$3.89	$0.00
Maximum Part-Peak Demand Summer	$1.89	$0.87	$0.00
Maximum Demand Summer	$1.94	$1.14	$0.08
Maximum Part-Peak Demand Winter	$1.85	$0.87	$0.00
Maximum Demand Winter	$1.94	$1.14	$0.08
Transmission Maximum Demand*	$2.32	$2.32	$2.32
Reliability Services Maximum Demand*	$2.02	$2.02	$2.02

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

(Continued)

COMMERCIAL/INDUSTRIAL/GENERAL
SCHEDULE E-19—MEDIUM GENERAL DEMAND-METERED TIME-OF-USE SERVICE
(Continued)

3. FIRM SERVICE RATES: (Cont'd.)

Table B (Non-FTA Rates) (Cont'd.)

UNBUNDLING OF TOTAL RATES (Cont'd.)

Energy Rates by Component ($ per kWh)	Secondary Voltage	Primary Voltage	Transmission Voltage
Generation:			
Peak Summer	$0.12037	$0.10205	$0.10713
Part-Peak Summer	$0.06547	$0.05950	$0.06668
Off-Peak Summer	$0.05310	$0.05189	$0.05848
Part-Peak Winter	$0.07025	$0.06673	$0.07930
Off-Peak Winter	$0.05294	$0.05278	$0.06259
Distribution:			
Peak Summer	$0.00912	$0.00288	$0.00933
Part-Peak Summer	$0.00603	$0.00224	$0.00708
Off-Peak Summer	$0.00526	$0.00217	$0.00665
Part-Peak Winter	$0.00664	$0.00263	$0.00873
Off-Peak Winter	$0.00523	$0.00219	$0.00718
Transmission Rate Adjustments* (all usage)	$0.00016	$0.00016	$0.00016
Public Purpose Programs (all usage)	$0.00472	$0.00433	$0.00447
Nuclear Decommissioning (all usage)	$0.00035	$0.00035	$0.00035
Competition Transition Charge (all usage)	$0.00448	$0.00448	$0.00448
Energy Cost Recovery Amount (all usage)	$0.00595 (I)	$0.00595 (I)	$0.00595 (I)
DWR Bond (all usage)	$0.00459	$0.00459	$0.00459

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

(Continued)

COMMERCIAL/INDUSTRIAL/GENERAL
SCHEDULE E-19—MEDIUM GENERAL DEMAND-METERED TIME-OF-USE SERVICE
(Continued)

3. FIRM SERVICE RATES: (Cont'd.)

a. TYPES OF CHARGES: The customer's monthly charge for service under Schedule E-19 is the sum of a customer charge, demand charges, and energy charges:

– The **customer charge** is a flat monthly fee.

– This schedule has three **demand charges,** a maximum-peak-period-demand charge, a maximum part-peak-period and a maximum-demand charge. The maximum-peak-period-demand charge per kilowatt applies to the maximum demand during the month's peak hours, the maximum part-peak-period demand charge applies to the maximum demand during the month's part-peak hours, and the maximum demand charge per kilowatt applies to the maximum demand at any time during the month. The bill will include all of these demand charges. (Time periods are defined in Section 6.) (T)

– The **energy charge** is the sum of the energy charges from the peak, partial-peak, and off-peak periods. The customer pays for energy by the kilowatt-hour (kWh), and rates are differentiated according to time of day and time of year.

– If applicable, all **TOU Installation** or **TOU Processing Charges** must be paid in one lump sum before the customer can take service under this rate schedule. Payments for these charges are not transferable to another service or refundable, in whole or part. PG&E will place the account on this schedule within four weeks of receiving payment from the customer. The meters required for this schedule may become obsolete as a result of electric industry restructuring or other action by the California Public Utilities Commission. Therefore, any and all risks of paying the required charges and not receiving commensurate benefit are entirely that of the customer. (T)

– The monthly charges may be increased or decreased based upon the power factor. (See Section 7.) (T)

– As shown on the rate chart, which set of customer, demand, and energy charges is paid depends on the level of the customers maximum demand and the voltage at which service is taken. Service voltages are defined in Section 5 below. (T)

– Please note that the rates in the table above apply only to firm service. Rates for non-firm service can be found in Section 12 of this rate schedule. (T)

(Continued)

COMMERCIAL/INDUSTRIAL/GENERAL
SCHEDULE E-19—MEDIUM GENERAL DEMAND-METERED TIME-OF-USE SERVICE
(Continued)

3. FIRM SERVICE RATES: (Cont'd.)

b. AVERAGE RATE LIMITER (applies to bundled, firm service only): If the customer takes service on Schedule E-19 in either the secondary or primary voltage class, bills will be controlled by a "rate limiter" during the summer months. The bill will be reduced if necessary so that the average rate paid for all demand and energy charges less the Energy Rate Adjustment (ERA) amount calculated using the applicable rates provided in Schedule E-ERA during a summer month does not exceed the average rate limiter shown on this Schedule. This provision will not apply if the customer has elected to receive separate billing for back-up and maintenance service under Special Condition 8 of Schedule S. (T)

Reductions in revenue resulting from application of the average rate limiter will be reflected as reduced distribution amounts for billing purposes.

c. PEAK-PERIOD RATE LIMITER (applies to bundled, firm service only): If the customer takes service on Schedule E-19 at any service voltage level, bills will be controlled by a "peak-period rate limiter" during the summer months. The bill will be reduced if necessary so that the average rate paid for all on-peak demand and energy charges less the peak period ERA amount calculated using the applicable rates provided in Schedule E-ERA during the peak period in a summer month does not exceed the peak-period rate limiter shown on this schedule. This provision will not apply if the customer has elected to receive separate billing for back-up and maintenance service under Special Condition 8 of Schedule S.

Reductions in revenue resulting from application of the peak-period rate limiter will be reflected as reduced distribution amounts for billing purposes.

(L)

(Continued)

COMMERCIAL/INDUSTRIAL/GENERAL
SCHEDULE E-19—MEDIUM GENERAL DEMAND-METERED TIME-OF-USE SERVICE
(Continued)

4. METERING REQUIREMENTS: (N)

PG&E will install a time-of-use meter that is appropriate for this schedule that measures and registers the amount of electricity a customer uses.

Customers whose maximum demand is less than 200 kW and whose account does not have an appropriate time-of-use meter must pay a **"Time-Of-Use Installation Charge"** prior to taking service under this schedule.

Customers with maximum demands of 200 kW or greater for three consecutive months must have an interval data meter that can be read remotely by PG&E, except customers that are identified as load research sites. A Meter Data Management Agent (MDMA) may also read the customer's meter on behalf of the customer's Energy Service Provider (ESP) if a customer is receiving Direct Access Service.

For bundled service customers with maximum demands of 200 kW or greater for three consecutive months, PG&E will provide and install the interval data metering equipment at no additional cost to the customer and will waive any Time-Of-Use Installation or Time-Of-Use Processing charges for those customers who are initially required to be placed on a time-of-use schedule. The installation of an interval data meter for customers taking service under the provisions of Direct Access is the responsibility of the customer's Energy Service Provider, or their Agent, and must be installed in accordance with Electric Rule 22.

Customers who also request any meter data management services, must also sign an Interval Meter Data Management Service Agreement (Form 79-985) and must have an appropriate interval data meter. If the customer does not currently qualify for an interval data meter, the customer must pay PG&E for the cost of purchasing and installing an hourly interval meter, together with applicable Income Tax Component of Contribution (N) (ITCC) charges and the cost to operate and maintain the interval meter, and must sign an Interval Meter Installation Service Agreement (Form 79-984).

5. DEFINITION OF SERVICE VOLTAGE: (T) (L)

The following defines the three voltage classes of Schedule E-19 rates. Standard Service Voltages are listed in Rule 2, Section B.1.

a. Secondary: This is the voltage class if the service voltage is less than 2,400 volts or if the definitions of "primary" and "transmission" do not apply to the service.

b. Primary: This is the voltage class if the customer is served from a "single customer substation" or without transformation from PG&E's serving distribution system at one of the standard primary voltages specified in PG&E's Electric Rule 2, Section B.1.

c. Transmission: This is the voltage class if the customer is served without transformation from PG&E's serving transmission system at one of the standard transmission voltages specified in PG&E's Rule 2, Section B.1. (L)

(Continued)

COMMERCIAL/INDUSTRIAL/GENERAL
SCHEDULE E-19—MEDIUM GENERAL DEMAND-METERED TIME-OF-USE SERVICE
(Continued)

6. DEFINITION OF TIME PERIODS:

Times of the year and times of the day are defined as follows: (T) (L)

SUMMER Period A (Service from May 1 through October 31):

Peak:	12:00 noon. to 6:00 p.m.	Monday through Friday (except holidays).
Partial-peak:	8:30 a.m. to 12:00 noon AND 6:00 p.m. to 9:30 p.m. Monday through Friday (except holidays).	
Off-peak:	9:30 p.m. to 8:30 a.m. All day	Monday through Friday Saturday, Sunday, and holidays (L)

WINTER Period B (service from November 1 through April 30):

Partial-Peak:	8:30 a.m. to 9:30 p.m.	Monday through Friday (except holidays).
Off-Peak:	9:30 p.m. to 8:30 a.m. All day	Monday through Friday (except holidays). Saturday, Sunday, and holidays

HOLIDAYS: “Holidays” for the purposes of this rate schedule are New Year’s Day, President’s Day, Memorial Day, Independence Day, Labor Day, Veterans Day, Thanksgiving Day, and Christmas Day. The dates will be those on which the holidays are legally observed.

CHANGE FROM SUMMER TO WINTER OR WINTER TO SUMMER: When a billing month includes both summer and winter days, PG&E will calculate demand charges as follows. It will consider the applicable maximum demands for the summer and winter portions of the billing month separately, calculate a demand charge for each, and then apply the two according to the number of billing days each represents.

7. POWER FACTOR ADJUSTMENTS:

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

The rates in this rate schedule are based on a power factor of 85 percent. If the average power factor is greater than 85 percent, the total monthly bill will be reduced by 0.06 percent of the bundled service bill less any taxes and the ERA amount calculated using applicable rates provided in Schedule E-ERA for each percentage point above 85 percent. If the average power factor is below 85 percent, the total monthly bill of the bundled service bill less any taxes and the ERA amount calculated using applicable rates provided in Schedule E-ERA will be increased by 0.06 percent for each percentage point below 85 percent.

Power factor adjustments will be assigned to distribution for billing purposes.

8. CHARGES FOR TRANSFORMER AND LINE LOSSES:

The demand and energy meter readings used in determining the charges will be adjusted to correct for transformation and line losses in accordance with Section B.4 of Rule 2. (T)

(Continued)

COMMERCIAL/INDUSTRIAL/GENERAL
SCHEDULE E-19—MEDIUM GENERAL DEMAND-METERED TIME-OF-USE SERVICE
(Continued)

9. STANDARD SERVICE FACILITIES: If PG&E must install any new or additional facilities to provide the customer with service under this schedule the customer may have to pay some of the cost. Any advance necessary and any monthly charge for the facilities will be specified in a line extension agreement. See Rules 2, 15, and 16 for details. This section does not apply to customers voluntarily taking service under Schedule E-19. (T)

Facilities installed to serve the customer may be removed when service is discontinued. The customer will then have to repay PG&E for all or some of its investment in the facilities. Terms and conditions for repayment will be set forth in the line extension agreement.

10. SPECIAL FACILITIES: PG&E will normally install only those standard facilities it deems necessary to provide service under this schedule. If the customer requests any additional facilities, those facilities will be treated as "special facilities" in accordance with Section I of Rule 2. (T)

11. ARRANGE-MENTS FOR VISUAL-DISPLAY METERING: If the customer wishes to have visual-display metering equipment in addition to the regular metering equipment, and the customer would like PG&E to install that equipment, the customer must submit a written request to PG&E. PG&E will provide and install the equipment within 180 days of receiving the request. The visual-display metering equipment will be installed near the present metering equipment. The customer will be responsible for providing the required space and associated wiring. (T)

PG&E will continue to use the regular metering equipment for billing purposes.

12. NON-FIRM SERVICE PROGRAM: As noted, the rates in the chart in Section 3 of this rate schedule apply to firm service only. ("Firm" means service where PG&E provides a "continuous and sufficient supply of electricity," as described in Rule 14.) A customer may also elect to receive non-firm service under Schedule E-19. Non-firm service is not available to customers taking service under Schedule E-19 on a voluntary basis. (T)

In accordance with Decision 01-04-006, the Non-firm Service Program is closed to new or existing customers that are not currently in the program. Existing contracts may not be assigned to other parties. Customers considering participating in an interruptible program should refer to Schedule E-BIP for program terms and conditions, or may consider other available interruptible or demand response programs. The customer's total load must meet the eligibility criteria in 11.a in order to participate in the Non-firm Service Program. Customers being served, as of December 31, 1992, under the Non-firm Service Program may continue to participate in the Non-firm Service Program.

(Continued)

COMMERCIAL/INDUSTRIAL/GENERAL
SCHEDULE E-19—MEDIUM GENERAL DEMAND-METERED TIME-OF-USE SERVICE
(Continued)

12. NON-FIRM SERVICE PROGRAM: (Cont'd.)

This program is available for qualifying customers until modified or terminated in the rate design phase of the next general rate case or similar proceeding as ordered in Decision 02-04-060. (T)

A customer who elects to receive non-firm service under Schedule E-19 must participate in PG&E's Emergency Curtailment Program. A non-firm service customer may also elect to participate in PG&E's Underfrequency Relay (UFR) program.

EMERGENCY CURTAILMENT PROGRAM: Under the Emergency Curtailment Program, a non-firm service customer may be requested to reduce demand to a designated number of kilowatts, referred to as the customer's contractual "firm service level." PG&E will make requests for such curtailments from its non-firm service customers upon notification from the California Independent System Operator (ISO) that a systemwide or local operating condition exists which will impair the ability of the ISO to meet the demands of PG&E's other customers. The ISO is expected to issue load curtailment directives to PG&E in those instances where load reductions are necessary in order to maintain systemwide operating reserves above the 5 percent level throughout the next operating hour, or if such load reductions are the sole remaining measure available in order to mitigate transmission overloads in the PG&E area.

(Continued)

COMMERCIAL/INDUSTRIAL/GENERAL
SCHEDULE E-19—MEDIUM GENERAL DEMAND-METERED TIME-OF-USE SERVICE
(Continued)

12. NON-FIRM SERVICE PROGRAM: (Cont'd.)

UNDERFREQUENCY RELAY PROGRAM: Under this program, the customer agrees to be subject at all times to automatic interruptions of service caused by an underfrequency relay device that may be installed by PG&E. (T)

Please note that PG&E may require up to three years' written notice for a change from non-firm to firm service, or for termination of participation in the Underfrequency Relay Program.

a. ELIGIBILITY CRITERIA FOR NON-FIRM SERVICE: To qualify for non-firm service, the customer must have had an average peak-period demand of at least 500 kilowatts during each of the last six summer billing months prior to the customer's application for non-firm service. (Average peak-period demand is the total number of kWh used during the peak-period hours of a billing month divided by the total number of peak-period hours in the month.) Customers who have not yet had six months of summer service must demonstrate to PG&E's satisfaction that they will maintain an average monthly-peak-period demand of 500 kW or more to qualify for non-firm service.

Customers on non-firm service may not have, or obtain, any insurance for the sole 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. Eligibility for the non-firm program requires that each customer execute and submit to PG&E a No Insurance Declaration that states that the customer does not have, and will not obtain such insurance.

Customers who are deemed essential under the Electric Emergency Plan as adopted in Decision 01-04-006 and Rulemaking 00-10-002, must submit to PG&E a written declaration that states that the customer is, to the best of that customer's understanding, an essential customer under Commission rules and exempt from rotating outages. It must also state that the customer voluntarily elects to participate in an interruptible program for part 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)

COMMERCIAL/INDUSTRIAL/GENERAL
SCHEDULE E-19—MEDIUM GENERAL DEMAND-METERED TIME-OF-USE SERVICE
(Continued)

12. NON-FIRM SERVICE PROGRAM: (Cont'd.)

b. DESIGNATION OF FIRM SERVICE LEVEL: If a customer takes non-firm service, the designated number of kilowatts to which the customer must reduce demand during emergency curtailments is the customer's contractual "firm service level." This designated firm service level must be at least 500 kilowatts less than the smallest of the customer's average peak-period demands during the last six summer billing months prior to the designation. (T)

c. PRE-EMERGENCY CURTAILMENT REQUIREMENTS: A customer may be requested to curtail, on a pre-emergency basis, up to a maximum of two times per year (except that emergency curtailments will count towards the maximum). Each pre-emergency curtailment will last no more than five hours. Customers will be given at least 30 minutes notice before each curtailment. The pre-emergency curtailments will be requested subject to the criteria listed in Section 12.d below, and PG&E's discretion. (T)

d. PRE-EMERGENCY CURTAILMENT PROCEDURE: PG&E will notify the customer by telephone, electronic mail, or other reliable means of communication. This notification will designate the time by which the customer's kW demand is requested to reduce to the customer's contractual firm service level. The notification will also designate the time when the customer may resume use of full power.

PG&E may call a pre-emergency curtailment if one of the following criteria are met:

1) The 9:00 a.m. forecast of temperatures in the Central Valley (the average of the forecasted temperature in Fresno and Sacramento) exceeds 100 degrees Fahrenheit; and PG&E has been informed by the ISO that an adjusted 10:00 a.m. forecast of two-hour reserves for that afternoon's peak is 12 percent or less; or

2) The 9:00 a.m. forecast of temperatures in the Central Valley exceeds 105 degrees Fahrenheit.

(Continued)

COMMERCIAL/INDUSTRIAL/GENERAL
SCHEDULE E-19—MEDIUM GENERAL DEMAND-METERED TIME-OF-USE SERVICE
(Continued)

12. NON-FIRM SERVICE PROGRAM: (Cont'd.)

e. EMERGENCY CURTAILMENT PROCEDURE: When it becomes necessary for PG&E to request a curtailment, PG&E will notify the customer by telephone, electronic mail, or other reliable means of communication. This notification will designate the time by which the customer's kW demand is requested to be reduced to the customer's contractual firm service level. (T)

The customer is requested to not resume the use of curtailed power until notified by PG&E that it may do so or until the customer has curtailed its service for six hours.

f. LIMIT ON EMERGENCY CURTAILMENTS: The number of curtailment events will not exceed one (1) per day, four (4) in a calendar week, and thirty (30) times per calendar year. The duration of the curtailment events will not exceed six (6) hours each, forty (40) hours per calendar month, and a total of one hundred (100) hours per calendar year.

The customer will be given at least 30 minutes notice before each curtailment.

Annual UFR operations shall not be included in the annual pre-emergency or emergency curtailment limit.

g. EMERGENCY-NOTICE PROVISION: If there is an emergency on the PG&E system, PG&E may ask the customer to curtail the use of electricity on less than the 30 minutes notice allowed for the Non-firm Service Option. The customer will be asked to make its best effort to comply. The customer will not be assessed the noncompliance penalty for failing to comply within the shorter notice period.

The customer will be assessed a noncompliance penalty if the regular notice period for the operation passes and the customer still has not curtailed use.

(Continued)

COMMERCIAL/INDUSTRIAL/GENERAL
SCHEDULE E-19—MEDIUM GENERAL DEMAND-METERED TIME-OF-USE SERVICE
(Continued)

12. NON-FIRM SERVICE PROGRAM: (Cont'd.)

h. NONCOMPLIANCE PENALTY: (T)

The applicable noncompliance penalties are listed in Section 12. If a customer has curtailed to or below the designated firm service level for all of the requested pre-emergency and emergency curtailments, if any, in the preceding calendar year, the noncompliance penalty for the current year, will be the lower level shown in Section 13. (T)

The penalty will be calculated by determining the total amount of excess energy taken during the curtailment period (energy taken in excess of the customer's firm service level times the duration of the curtailment) and multiplying this total by the noncompliance penalty (per KWh).

Once a customer has complied with all the requested curtailments during the previous year, the customer's noncompliance penalty will remain at the reduced penalty level shown in Section 13 for the next calendar year. If the customer fails (T) to comply with a requested curtailment, the noncompliance penalty for the following year will be the higher value shown in Section 13. (T)

If no emergency or pre-emergency curtailments are called during a given year, the customer's noncompliance penalty for the next year in which curtailments occur shall be based on the customer's level of compliance during the last year curtailments were called.

During the year, PG&E will record any energy taken in excess of the customer's firm service level during any emergency or pre-emergency curtailments. PG&E will notify the customer of the amount of excess energy taken and the estimated noncompliance penalty. PG&E shall assess the noncompliance penalties, subject to the noncompliance penalty limit described below, at the end of the calendar year. The customer's noncompliance penalty shall be equal to the appropriate noncompliance penalty shown in Section 13 times the total amount of excess (T) energy taken during any pre-emergency and emergency curtailments.

In any given calendar year, the noncompliance penalties may not exceed 200 percent of the annual incentive level. The noncompliance penalty limit is equal to twice the annual incentive paid (the difference between what the customer would have paid on firm service rates less the customer's bill on non-firm rates excluding any noncompliance penalties). If a customer's total noncompliance penalties in any given year exceed the noncompliance penalty limit, PG&E shall bill the customer a noncompliance penalty equal to the noncompliance penalty limit.

(Continued)

COMMERCIAL/INDUSTRIAL/GENERAL
SCHEDULE E-19—MEDIUM GENERAL DEMAND-METERED TIME-OF-USE SERVICE
(Continued)

12. NON-FIRM SERVICE PROGRAM: (Cont'd.)

i. ADDITIONAL NON-FIRM SERVICE PROVISIONS: (T)

1) **Required Re-Designations of Firm Service Level**: A non-firm service customer must maintain a difference of at least 500 kW between the firm service level and the average monthly summer peak-period demand. If the difference is less than 500 kW for any three summer months during any 12-month period, the customer must designate a new firm service level. This new firm service level must be at least 500 kW below the lowest of the customer's average peak-period demands for the last six summer billing months preceding the new designation. If the customer cannot meet this requirement, PG&E will change the account to firm service.

2) **Optional Re-Designations of Firm Service Level:** A non-firm service customer may decrease the firm service level effective with the start of any billing month, provided the customer gives PG&E at least 30 days' written notice. The customer may increase the firm service level (or return to firm service) only with PG&E's permission or by giving such notice to PG&E during a one-month period following any revisions of the program operating criteria initiated by the ISO, or during an annual contract review period that is provided for between November 1 and December 1 each year. The increased firm service level must be such that there is still at least a 500 kW difference between the firm service level and the lowest average monthly summer peak-period demand. The increased firm service level will become effective with the first regular reading of the meter after the customer receives permission from PG&E or at the end of the three year notice period. If a customer elects to change to firm service, it will not be permitted to subsequently return to non-firm status in the future.

3) **Telephone Line Requirements:** Non-firm customers are required to make available a telephone line and space for a notification printer. This requirement is in addition to any other equipment requirement which may apply.

j. BILL REDUCTIONS FOR NON-FIRM SERVICE CUSTOMERS:

1) **Demand Charges:** Reduced peak-period demand charges for curtailable service shall be applied to the difference between the customer's maximum demand in the peak-period and its Firm Service Level (but not less than zero). The peak-period charges for firm service shall be applied to the peak-period demand less the above difference.

2) **Energy Charges:** Reduced energy charges for curtailable service shall be applied to (a-b), where (a) is the number of kilowatt-hours used in the time period and (b) is the product of the Firm Service Level and the number of hours in the time period. (a-b) shall not be less than zero.

(Continued)

COMMERCIAL/INDUSTRIAL/GENERAL
SCHEDULE E-19—MEDIUM GENERAL DEMAND-METERED TIME-OF-USE SERVICE
(Continued)

12. NON-FIRM SERVICE PROGRAM: (Cont'd.)

k. PROVISIONS SPECIFIC TO UFR PROGRAM: (T)

1) **Details on Automatic Interruptions:** If a customer is participating in the UFR program, service to the customer will be automatically interrupted if the frequency on the PG&E system drops to 59.65 hertz for 20 cycles. PG&E will install and maintain a digital underfrequency relay and whatever associated equipment it believes is necessary to carry out such automatic interruption. Relays and other equipment will remain the property of PG&E. If more than one relay is required, PG&E will provide the additional relays as "special facilities," at customer's expense, in accordance with Section I of Rule 2.

   In addition to the underfrequency relay, PG&E may install equipment that would automatically interrupt service in case of voltage reductions or other operating conditions.

2) **Metering Requirements for UFR Program:** If a customer is participating in the UFR program under Schedule E-19 in combination with firm or curtailable-only service, the customer will be required to have a separate meter for the UFR service. PG&E will provide the meter sets, but the customer will be responsible for arranging customer's wiring in such a way that the service for each account can be provided and metered at a single point. NOTE: Any other additional facilities required for a combination of curtailable with firm service will be treated as "special facilities" in accordance with Section I of Rule 2.

3) **Communication Channel for UFR Service:** UFR program customers are required to provide an exclusive communication channel from the PG&E-provided terminal block at the customer's facility to a PG&E-designated control center. The communication channel must meet PG&E's specifications, and must be provided at the customer's expense. PG&E shall have the right to inspect the communication circuit upon reasonable notice.

(Continued)

COMMERCIAL/INDUSTRIAL/GENERAL
SCHEDULE E-19—MEDIUM GENERAL DEMAND-METERED TIME-OF-USE SERVICE
(Continued)

12. NON-FIRM SERVICE PROGRAM: (Cont'd.)

l. INTERACTIONS WITH OTHER DEMAND RESPONSE PROGRAMS: (T)

1. Customers who participate in a third-party sponsored interruptible load program must immediately notify PG&E of such activity.

2. Participants in the non-firm program may also participate in the Demand Bidding Program (Schedule E-DBP), but will not be paid the energy reduction incentives under the Schedule E-DBP during those hours where a non-firm event is issued.

3. Participants in the non-firm program may participate in the Optional Binding Mandatory Curtailment Program (Schedule E-OBMC) and the Pilot Optional Binding Mandatory Curtailment Program (Schedule E-POBMC) subject to meeting all applicable eligibility, operational and participation requirements specified in those schedules.

4. Participants in the non-firm program may participate in the Call Option of the California Power Authority Demand Reserves Partnership (CPA-DRP) program provided the additional load committed to the CPA-DRP is below their Firm Service Level (FSL) under the non-firm program. Participants in the non-firm program may participate in the Supplemental Energy Market Option of the CPA-DRP program, but will not be paid for curtailments under the California Power Authority's program during those hours when a non-firm event is issued. Participants in the non-firm program may not participate in the Ancillary Service Option of the CPA-DRP program.

5. Participants on the non-firm program shall not participate in the Scheduled Load Reduction Program (Schedule E-SLRP), or the Critical Peak Pricing Program (Schedule E-CPP) while on the non-firm program. Participants on the non-firm program may participate in the Base Interruptible Program (Schedule E-BIP) only after they have completed their annual obligations under the non-firm program.

(Continued)

COMMERCIAL/INDUSTRIAL/GENERAL
SCHEDULE E-19—MEDIUM GENERAL DEMAND-METERED TIME-OF-USE SERVICE
(Continued)

13. NON-FIRM SERVICE RATES: These rates are applicable if the customer elects to take non-firm service. See Section 11 for an explanation of the non-firm service program and eligibility criteria.

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

TOTAL RATES

Total Customer/Meter Charge Rates	Secondary Voltage	Primary Voltage	Transmission Voltage
Nonfirm Customer Charge ($ per meter per day)	$11.99179	$10.84189	$26.28337
Nonfirm w/UFR Customer Charge ($ per meter per day)	$12.32033	$11.17043	$26.61191
Optional Meter Data Access Charge ($ per meter per day)	$ 0.98563	$ 0.98563	$ 0.98563
Total Demand Rates ($ per kW)			
Maximum Peak Demand Summer	$5.62	$3.78	($0.65)
Maximum Part-Peak Demand Summer	$3.14	$2.04	$0.05
Maximum Demand Summer	$3.00	$3.01	$0.67
Maximum Part-Peak Demand Winter	$3.08	$2.04	$0.19
Maximum Demand Winter	$3.00	$3.01	$0.67
Total Energy Rates ($ per kWh)			
Peak Summer	$0.13727 (I)	$0.11232 (I)	$0.12399 (I)
Part-Peak Summer	$0.09043 |	$0.08028 |	$0.09244 |
Off-Peak Summer	$0.07729 |	$0.07260 |	$0.08381 |
Part-Peak Winter	$0.09582 |	$0.08790 |	$0.10671 |
Off-Peak Winter	$0.07710 (I)	$0.07351 (I)	$0.08845 (I)
Noncompliance Penalty ($ per kWh per event)	$8.40	$8.40	$8.40
Noncompliance Penalty ($ per kWh per event) (For customers who fully complied with the previous years operation)	$4.20	$4.20	$4.20
UFR Credit ($ per kWh, if applicable)	$0.00091	$0.00091	$0.00091

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

UNBUNDLING OF TOTAL RATES

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

Demand Rate by Component ($ per kW)	Secondary Voltage	Primary Voltage	Transmission Voltage
Generation:			
Maximum Peak Demand Summer	$6.33	$7.39	$6.85
Maximum Part-Peak Demand Summer	$1.75	$1.67	$0.55
Maximum Demand Summer	($3.28)	($2.47)	($3.75)
Maximum Part-Peak Demand Winter	$1.73	$1.67	$0.69
Maximum Demand Winter	($3.28)	($2.47)	($3.75)
Distribution:			
Maximum Peak Demand Summer	($0.71)	($3.61)	($7.50)
Maximum Part-Peak Demand Summer	$1.39	$0.37	($0.50)
Maximum Demand Summer	$1.94	$1.14	$0.08
Maximum Part-Peak Demand Winter	$1.35	$0.37	($0.50)
Maximum Demand Winter	$1.94	$1.14	$0.08
Transmission Maximum Demand*	$2.32	$2.32	$2.32
Reliability Services Maximum Demand*	$2.02	$2.02	$2.02

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

(Continued)

COMMERCIAL/INDUSTRIAL/GENERAL
SCHEDULE E-19—MEDIUM GENERAL DEMAND-METERED TIME-OF-USE SERVICE
(Continued)

13. NON-FIRM SERVICE RATES: (Cont'd.)

UNBUNDLING OF TOTAL RATES (Cont'd.)

Energy Rates by Component ($ per kWh)	Secondary Voltage	Primary Voltage	Transmission Voltage
Generation:			
Peak Summer	$0.12037	$0.10205	$0.10713
Part-Peak Summer	$0.06547	$0.05950	$0.06668
Off-Peak Summer	$0.05310	$0.05189	$0.05848
Part-Peak Winter	$0.07025	$0.06673	$0.07930
Off-Peak Winter	$0.05294	$0.05278	$0.06259
Distribution:			
Peak Summer	($0.00335)	($0.00959)	($0.00314)
Part-Peak Summer	$0.00471	$0.00092	$0.00576
Off-Peak Summer	$0.00394	$0.00085	$0.00533
Part-Peak Winter	$0.00532	$0.00131	$0.00741
Off-Peak Winter	$0.00391	$0.00087	$0.00586
Noncompliance Penalty ($ per kWh per event)	$8.40	$8.40	$8.40
Noncompliance Penalty ($ per kWh per event) (For customers who fully complied with the previous years operation)	$4.20	$4.20	$4.20
UFR Credit ($ per kWh, if applicable)	$0.00091	$0.00091	$0.00091
Transmission Rate Adjustments* (all usage)	$0.00016	$0.00016	$0.00016
Public Purpose Programs (all usage)	$0.00472	$0.00433	$0.00447
Nuclear Decommissioning (all usage)	$0.00035	$0.00035	$0.00035
Competition Transition Charge (all usage)	$0.00448	$0.00448	$0.00448
Energy Cost Recovery Amount (all usage)	$0.00595 (I)	$0.00595 (I)	$0.00595 (I)
DWR Bond (all usage)	$0.00459	$0.00459	$0.00459

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

(Continued)

COMMERCIAL/INDUSTRIAL/GENERAL
SCHEDULE E-19—MEDIUM GENERAL DEMAND-METERED TIME-OF-USE SERVICE
(Continued)

14. COMMON-AREA ACCOUNTS: Common-area accounts that are separately metered by PG&E and which took electric service from PG&E on or prior to January 16, 2003, have a one-time opportunity to return to a residential rate schedule from April 1, 2004, to May 31, 2004, by notifying PG&E in writing. (T)

In the event that the CPUC substantially amends any or all of PG&E's commercial or residential rate schedules, the Executive Council of Homeowners (ECHO) can direct PG&E to begin an optional second right-of-return period lasting 105 days. However, if this occurs prior to the April 1, 2004, to May 31, 2004, time period, the ECHO directed right of return period will be the only window for returning to a residential schedule.

Newly constructed common-areas that are separately metered by PG&E and which first took electric service from PG&E after January 16, 2003, have a one-time opportunity to transfer to a residential rate schedule during a two-month window that begins 14 months after taking service on a commercial rate schedule. This must be done by notifying PG&E in writing. These common-area accounts have an additional opportunity to return to a residential schedule in the event that ECHO directs PG&E to begin a second right-of-return period.

Only those common-area accounts taking service on Schedule E-8 prior to moving to this tariff may return to Schedule E-8.

Common-area accounts are those accounts that provide electric service to Common Use Areas as defined in Rule 1.

15. CONTRACTS: STANDARD SERVICE AGREEMENT: To begin service under Schedule E-19 for customers with maximum demands greater than 499 kW, the customer shall be required to sign PG&E's Electric General Service Agreement (GSA). The GSA has an initial term of three (3) years, once the three-year initial term is over, the agreement will automatically continue in effect for successive terms of one year each until it is cancelled. Customers may, at any time, request PG&E to modify the GSA if the service arrangements, electrical demand requirements, or delivery criteria to its premises change. However, customers will still be obligated to perform the terms and conditions outlined in any other agreements that supplement the GSA. (T)

(Continued)

COMMERCIAL/INDUSTRIAL/GENERAL
SCHEDULE E-19—MEDIUM GENERAL DEMAND-METERED TIME-OF-USE SERVICE
(Continued)

16. VOLUNTARY SERVICE PROVISIONS: Customers voluntarily taking service on Schedule E-19 (see Applicability Section) shall be governed by all the terms and conditions shown in Sections 1 through 13, unless different terms and conditions are shown below. (T)

a. DEFINITION OF MAXIMUM DEMAND: Demand will be averaged over 15-minute intervals except, in special cases. “Maximum demand” will be the highest of all 15-minute averages for the billing month.

SPECIAL CASES: (1) If the customer’s maximum demand has exceeded 400 kW for three consecutive months, 30-minute intervals will be used for averaging. The customer will be returned to 15-minute intervals when its maximum demand has dropped below 300 kW and remains there for 12 consecutive months. (2) If the customer’s use of energy is intermittent or subject to violent fluctuations, a 5-minute or 15-minute interval may be used. (3) If the customer uses welders, the demand charge will be subject to the minimum demand charges for those welders' ratings, as explained in Section J of Rule 2.

b. REDUCED CUSTOMER CHARGE: The reduced customer charge will be assessed only if the customer is taking service under this schedule on a voluntary basis or if the customer’s maximum billing demand has not exceeded 499 kW for 12 or more consecutive months.

c. SERVICE CONTRACTS: This rate schedule will remain in effect for at least twelve consecutive months before another schedule change is made, unless the customer’s maximum demand has exceeded 499 kW for three consecutive months.

17. BILLING: A customer’s bill is calculated based on the option applicable to the customer. (T)

(Continued)

COMMERCIAL/INDUSTRIAL/GENERAL
SCHEDULE E-19—MEDIUM GENERAL DEMAND-METERED TIME-OF-USE SERVICE
(Continued)

17. BILLING: (Cont'd.)

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

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

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

	DA CRS		CCA CRS	
Energy Cost Recovery Amount Charge (per kWh)	$0.00595	(I)	$0.00595	(I)
DWR Power Charge (per kWh)	$0.01198	(R)	$0.01552	
DWR Bond Charge (per kWh)	$0.00459		$0.00459	
Ongoing CTC Charge (per kWh)	$0.00448		$0.00448	
Total CRS (per kWh)	$0.02700		$0.03054	(I)

18. FIXED TRANSITION AMOUNT:

Eligible small commercial customers that received the benefit of the 10 percent rate reduction prior to January 1, 2004, are obligated to pay a Fixed Transition Amount (FTA), also referred to as a Trust Transfer Amount (TTA), as described in Schedule E-RRB and defined in Preliminary Statement Part AS. In addition, these customers will receive the benefit of the rate reduction bond memorandum account rate.

19. CARE DISCOUNT FOR NONPROFIT GROUP-LIVING AND SPECIAL EMPLOYEE HOUSING FACILITIES:

Facilities which meet the eligibility criteria in Rule 19.2 or 19.3 are eligible for a California Alternate Rates for Energy discount under Schedule E-CARE. CARE customers are exempt from paying the DWR Bond Charge rate component. For CARE customers, no portion of the rates shall be used to pay the DWR bond charge. Generation is calculated residually based on the total rate less the sum of the following: Transmission, Transmission Rate Adjustments, Reliability Services, Distribution, Public Purpose Programs, Nuclear Decommissioning, Competition Transition Charges (CTC), Energy Cost Recovery Amount, FTA and the Rate Reduction Bond Memorandum Account Rate.

(Continued)

COMMERCIAL/INDUSTRIAL/GENERAL
SCHEDULE E-19—MEDIUM GENERAL DEMAND-METERED TIME-OF-USE SERVICE
(Continued)

20. OPTIONAL OPTIMAL BILLING PERIOD SERVICE: The Optimal Billing Period service is an experimental program that is limited to a maximum of 150 bundled service accounts at any one time. Customers electing this optional service must sign the Optimal Billing Service Customer Election Form (Standard Form 79-842). (T)

a. Eligibility

On an experimental pilot basis and subject to the availability and installation of solid state recorder equipment, firm service primary and secondary voltage customers whose maximum demand exceeds 500 kW for three consecutive billing months may select the “optimal billing period” service on a voluntary basis in up to two “subject” months (subject month is defined as the month in which the production cycle starts or ends), one at the start and one at the end of the customer’s high seasonal production cycle. The meter read date separating the subject month and the “adjacent” month (the adjacent month follows the subject month at the start of production, but precedes it at the end of production) would be redesignated to an alternative read date. In no event shall any revised billing period exceed 45 days nor be less than 15 days. Where the start date is in a summer month, the summer season average rate limiter must otherwise apply to the subject month at the start of the customer’s high production cycle, but need not apply to the subject month at the end of production or the two adjacent months.

(Continued)

COMMERCIAL/INDUSTRIAL/GENERAL
SCHEDULE E-19—MEDIUM GENERAL DEMAND-METERED TIME-OF-USE SERVICE
(Continued)

20. OPTIONAL OPTIMAL BILLING PERIOD SERVICE: (Cont'd.)

a. Eligibility (Cont'd.) (T)

The customer would retain the protection of the summer average rate limiter in all summer months including the revised subject and adjacent months, where the rate limiter is imposed before the additional customer charge in Section 21.c has been included in the bill calculation. (T)

To qualify, the duration of the customer's high seasonal production period must be six (6) months or less, and the customer's energy consumption during its high seasonal production cycle must be at least 2.0 times its consumption during its low seasonal production cycle for the most recent twelve (12) month period. Customers that discontinue this option may not enroll in this option again for a period of twelve (12) months. The customer must also specify which six (6) consecutive calendar months will be the optimal billing period. The optimal billing period must encompass the customer's high seasonal production period.

b. Customer Notification to PG&E

Upon enrollment, the customer shall notify PG&E of the approximate two months where seasonal production starts and ends. As they occur, the customer shall notify PG&E of the exact seasonal production start and end dates. Upon notification by the customer of a production start date during a summer month, PG&E will wait until the regular read date to verify that the regular subject month bill would have otherwise invoked the rate limiter. If the rate limiter is invoked for the summer subject start month, the customer will be billed based on the optimal meter read dates or the regular scheduled meter read dates, whichever is the lower bill. Throughout the six month period, customers will receive their regular bill. Approximately two months after the production start or end date, the customer will receive a credit, if one should apply, for the optimal billing period. If a credit does not apply, the customer will not receive additional billing. If the rate limiter does not otherwise apply, the regular subject month bill based on the old read date will be issued, and the customer can then request the special optimal bill option in only one production end date "subject" month. The application of this billing option to a production end date may occur prior to its application to a production start date, such as when a customer has more than one high production cycle. The customer must notify PG&E in writing, via facsimile (fax) to both the PG&E account representative and PG&E's Customer Billing Department, of the production start or end date within two days of the production start or end date. Customers will receive from PG&E's Customer Billing Department a fax receipt verification upon notice of a production start or end date. PG&E will notify the customer of the regularly scheduled meter read dates and, upon request, the customer's rate limiter history.

(Continued)

COMMERCIAL/INDUSTRIAL/GENERAL
SCHEDULE E-19—MEDIUM GENERAL DEMAND-METERED TIME-OF-USE SERVICE
(Continued)

20. OPTIONAL OPTIMAL BILLING PERIOD SERVICE: (Cont'd.)

c. Customer Charge (T)

Upon enrollment, a special customer charge will be assessed in all six (6) months in the optimal billing period to cover the incremental costs of the required solid state recorder, special program billing, recruitment, and administrative costs. The customer is obligated to pay this monthly customer charge only while enrolled in this option but any customer that drops out may not enroll in this option again for a period of twelve (12) months. Customers who have signed contracts and are awaiting solid state recorders so that they can participate in the program will not be assessed the special customer charge until a solid state recorder has been installed.

For billing purposes, the special customer charge for the optimal billing period service shall be assigned to Distribution.

d. Proration of Charges

All applicable customer charges, demand charges or other applicable fixed charges, shall be prorated as specified in Rule 9. As specified in Rule 9, Sections A and B, the regular billing period will be once each month, and prorations for monthly bills of less than 27 or more than 33 days shall be calculated on the basis of the number of days in the period in question to the total number of days in an average month, as specified in Rule 9.

e. Functional Assignment of Credit

For billing purposes, the Optimal Billing Credit will be assigned to Distribution.

21. ELECTRIC EMERGENCY PLAN ROTATING BLOCK OUTAGES

As set forth in CPUC Decision 01-04-006, all transmission level customers except essential use customers, OBMC participants, net suppliers to the electrical grid, or others exempt by the Commission, are to be included in rotating outages in the event of an emergency. A transmission level customer who refuses or fails to drop load shall be added to the next rotating outage group so that the customer does not escape curtailment. If the transmission level customer fails to cooperate and drop load at PG&E's request, automatic equipment controlled by PG&E will be installed at the customer's expense per Electric Rule 2. A transmission level customer who refuses to drop load before installation of the equipment shall be subject to a penalty of \$6/kWh for all load requested to be curtailed that is not curtailed. The \$6/kWh penalty shall not apply if the customer's generation suffers a verified, forced outage and during times of scheduled maintenance. The scheduled maintenance must be approved by both the ISO and PG&E, but approval may not be unreasonably withheld. (T)

(Continued)

COMMERCIAL/INDUSTRIAL/GENERAL
SCHEDULE E-19—MEDIUM GENERAL DEMAND-METERED TIME-OF-USE SERVICE
(Continued)

22. STANDBY APPLICABILITY:

SOLAR GENERATION FACILITIES EXEMPTION: Customers who utilize solar generating facilities which are less than or equal to one megawatt to serve load and who do not sell power or make more than incidental export of power into PG&E's power grid and who have not elected service under Schedule E-NEM, will be exempt from paying the otherwise applicable standby reservation charges. (T)

DISTRIBUTED ENERGY RESOURCES EXEMPTION: Any customer under a time-of-use rate schedule using electric generation technology that meets the criteria as defined in Electric Rule 1 for Distributed Energy Resources is exempt from the otherwise applicable standby reservation charges. Customers qualifying for this exemption shall be subject to the following requirements. Customers qualifying for an exemption from standby charges under Public Utilities (PU) Code Sections 353.1 and 353.3, as described above, must take service on a time-of-use (TOU) schedule in order to receive this exemption until a real-time pricing program, as described in PU Code 353.3, is made available. Once available, customers qualifying for the standby charge exemption must participate in the real-time program referred to above. Qualification for and receipt of this distributed energy resources exemption does not exempt the customer from metering charges applicable to time-of-use (TOU) and real-time pricing, or exempt the customer from reasonable interconnection charges, non-bypassable charges as required in Preliminary Statement BB - *Competition Transition Charge Responsibility for All Customers and CTC Procurement*, or obligations determined by the Commission to result from participation in the purchase of power through the California Department of Water Resources, as provided in PU Code Section 353.7.

23. DWR BOND CHARGE:

The Department of Water Resources (DWR) Bond Charge was imposed by California Public Utilities Commission Decision 02-10-063, as modified by Decision 02-12-082, and is property of DWR for all purposes under California law. The Bond Charge applies to all retail sales, excluding CARE and Medical Baseline sales. The DWR Bond Charge (where applicable) is included in customers' total billed amounts. (T)

COMMERCIAL/INDUSTRIAL/GENERAL
SCHEDULE E-20—SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS OF 1,000 KILOWATTS OR MORE

CONTENTS: This rate schedule is divided into the following sections:

1. APPLICABILITY: **Initial Assignment:** A customer is eligible for service under Schedule E-20 if the customer's maximum demand (as defined below) has exceeded 999 kilowatts for at least three consecutive months during the most recent 12-month period. If 70 percent or more of the customer's energy use is for agricultural end-uses, the customer will be served under an agricultural schedule.

Customer accounts which fail to qualify under these requirements will be evaluated for transfer to service under a different applicable rate schedule. (D)

The provisions of Schedule S—Standby Service Special Conditions 1 through 6 shall also apply to customers whose premises are regularly supplied in part (but not in whole) by electric energy from a nonutility source of supply. These customers will pay monthly reservation charges as specified under Section 1 of Schedule S, in addition to all applicable Schedule E-20 charges. Exemptions to standby charges are outlined in the Standby Applicability Section of this rate schedule.

Transfers Off of Schedule E-20: PG&E will review its Schedule E-20 accounts annually. A customer will be eligible for continued service on Schedule E-20 if its maximum demand has either: (1) Exceeded 999 kilowatts for at least 5 of the previous 12 billing months, or (2) Exceeded 999 kilowatts for any 3 consecutive billing months of the previous 14 billing months. If a customer's demand history fails both of these tests, PG&E will transfer that customer's account to service under a different applicable rate schedule, except as specified in the Energy Efficiency Adjustment provision below.

Assignment of New Customers: If a customer is new and PG&E believes that the customer's maximum demand will exceed 999 kilowatts and that the customer should not be served under a time-of-use agricultural schedule, PG&E will serve the customer's account under Schedule E-20.

(Continued)

COMMERCIAL/INDUSTRIAL/GENERAL
SCHEDULE E-20—SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS OF 1,000 KILOWATTS OR MORE
(Continued)

1. APPLICABILITY: (Cont'd.)

Definition of Maximum Demand: Demand will be averaged over 30-minute intervals. "Maximum demand" will be the highest of all the 30-minute averages for the billing month. If the customer's use of electricity is intermittent or subject to violent fluctuations, a 5-minute or 15-minute interval may be used instead of the 30-minute interval. If the customer has any welding machines, the diversified resistance welder load, calculated in accordance with Section J of Rule 2, will be considered the maximum demand if it exceeds the maximum demand that results from averaging the demand over 30-minute intervals. The customer's maximum-peak-period demand will be the highest of all the 30-minute averages for the peak period during the billing month. (See Section 5 for a definition of "Peak-Period.")

Standby Demand: For customers for whom Schedule S—Standby Service Special Conditions 1 through 6 apply, standby demand is the portion of a customer's maximum demand in any month caused by nonoperation of the customer's alternate source of power, and for which a demand charge is paid under the regular service schedule.

If the customer imposes standby demand in any month, then the regular service maximum demand charge will be reduced by the applicable reservation capacity charge (see Schedule S Special Condition 1).

To qualify for the above reduction in the maximum demand charge, the customer must, within 30 days of the regular meter read date, demonstrate to the satisfaction of PG&E the amount of standby demand in any month. This may be done by submitting to PG&E a completed Electric Standby Service Long Sheet (Form 79-726).

Energy Efficiency Adjustment: A customer who implements measures to improve electrical energy efficiency on or after January 1, 1990, may be eligible to receive an energy efficiency adjustment. A customer will qualify for an energy efficiency adjustment if both following conditions are met: (1) the customer's service was established prior to January 1, 1990, and (2) the energy efficiency measures reduce the customer's maximum demand to the point that the customer would no longer be eligible for service under Schedule E-20.

To receive the energy efficiency adjustment, the customer must qualify for and sign an Agreement for Maximum Demand Adjustment for Energy Efficiency Measures (Form No. 79-758). The energy efficiency adjustment shall be the fixed reduction in demand specified in Form 79-758, and shall be added to the customer's maximum demand for the sole purpose of determining the customer's eligibility for Schedule E-20.

The energy efficiency adjustment specifically does not guarantee the customer's continued eligibility for service under Schedule E-20. The energy efficiency adjustment will not be applied to the customer's maximum demand for the purposes of calculating the monthly maximum demand charge.

(D)

2. TERRITORY: Schedule E-20 applies everywhere PG&E provides electricity service. (L)

(Continued)

COMMERCIAL/INDUSTRIAL/GENERAL
SCHEDULE E-20—SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS OF 1,000 KILOWATTS OR MORE
(Continued)

3. FIRM SERVICE RATES: (Cont'd.)

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

TOTAL RATES

Total Customer/Meter Charge Rates	Secondary Voltage		Primary Voltage		Transmission Voltage	
Customer Charge Mandatory E-20 ($ per meter per day)	$12.64887		$10.18480		$23.49076	
Optional Optimal Billing Period Service ($ per meter per month)	$130.00		$130.00		–	
Optional Meter Data Access Charge ($ per meter per day)	$0.98563		$0.98563		$0.98563	
Total Demand Rates ($ per kW)						
Maximum Peak Demand Summer	$13.00		$11.13		$6.88	
Maximum Part-Peak Demand Summer	$3.61		$2.50		$0.55	
Maximum Demand Summer	$3.08		$3.09		$0.75	
Maximum Part-Peak Demand Winter	$3.56		$2.50		$0.69	
Maximum Demand Winter	$3.08		$3.09		$0.75	
Total Energy Rates ($ per kWh)						
Peak Summer	$0.14786	(I)	$0.12131	(I)	$0.11342	(I)
Part-Peak Summer	$0.08441	|	$0.07421	|	$0.06860	|
Off-Peak Summer	$0.07743	|	$0.07251	|	$0.06617	|
Part-Peak Winter	$0.08980	|	$0.08157	|	$0.07784	|
Off-Peak Winter	$0.07724	(I)	$0.07326	(I)	$0.06914	(I)
Average Rate Limiter ($/kWh in summer months)	$0.13995		$0.13995		–	
Peak Period Rate Limiter ($/kWh in summer months)	$0.97708		$0.84876		$0.55750	

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

UNBUNDLING OF TOTAL RATES

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

Demand Rates by Component ($ per kW)	Secondary	Primary	Transmission
Generation:			
Maximum Peak Demand Summer	$7.07	$8.21	$6.88
Maximum Part-Peak Demand Summer	$1.95	$1.83	$0.55
Maximum Demand Summer	($3.68)	($2.62)	($3.87)
Maximum Part-Peak Demand Winter	$1.92	$1.83	$0.69
Maximum Demand Winter	($3.68)	($2.62)	($3.87)
Distribution:			
Maximum Peak Demand Summer	$5.93	$2.92	$0.00
Maximum Part-Peak Demand Summer	$1.66	$0.67	$0.00
Maximum Demand Summer	$2.14	$1.09	$0.00
Maximum Part-Peak Demand Winter	$1.64	$0.67	$0.00
Maximum Demand Winter	$2.14	$1.09	$0.00
Transmission Maximum Demand*	$2.44	$2.44	$2.44
Reliability Services Maximum Demand*	$2.18	$2.18	$2.18

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

(Continued)

COMMERCIAL/INDUSTRIAL/GENERAL
SCHEDULE E-20— SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS OF 1,000 KILOWATTS OR MORE
(Continued)

3. FIRM SERVICE RATES: (Cont'd.)

UNBUNDLING OF TOTAL RATES (Cont'd.)

Energy Rates by Component ($ per kWh)	Secondary Voltage	Primary Voltage	Transmission Voltage
Generation:			
Peak Summer	$0.11410	$0.09835	$0.09558
Part-Peak Summer	$0.05532	$0.05216	$0.05085
Off-Peak Summer	$0.04952	$0.05058	$0.04842
Part-Peak Winter	$0.05981	$0.05898	$0.06009
Off-Peak Winter	$0.04936	$0.05129	$0.05139
Distribution:			
Peak Summer	$0.01383	$0.00417	$0.00027
Part-Peak Summer	$0.00916	$0.00326	$0.00018
Off-Peak Summer	$0.00798	$0.00314	$0.00018
Part-Peak Winter	$0.01006	$0.00380	$0.00018
Off-Peak Winter	$0.00795	$0.00318	$0.00018
Transmission Rate Adjustments* (all usage)	$0.00016	$0.00016	$0.00016
Public Purpose Programs (all usage)	$0.00454	$0.00402	$0.00326
Nuclear Decommissioning (all usage)	$0.00035	$0.00035	$0.00035
Competition Transition Charge (all usage)	$0.00434	$0.00372	$0.00326
Energy Cost Recovery Amount (all usage)	$0.00595 (I)	$0.00595 (I)	$0.00595 (I)
DWR Bond (all usage)	$0.00459	$0.00459	$0.00459

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

(Continued)

COMMERCIAL/INDUSTRIAL/GENERAL
SCHEDULE E-20—SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS OF 1,000 KILOWATTS OR MORE
(Continued)

3. FIRM SERVICE RATES: (Cont'd.)

a. TYPES OF CHARGES: The customer's monthly charge for service under Schedule E-20 is the sum of a customer charge, demand charges, and energy charges:

– The **energy charge** is the sum of the energy charges from the peak, partial-peak, and off-peak periods. The customer pays for energy by the kilowatt-hour (kWh), and rates are differentiated according to time of day and time-of-year.

– The monthly charges may be increased or decreased based upon the power factor. (See Section 7.) (T)

– The **customer charge** is a flat monthly fee.

– Schedule E-20 has three **demand charges**, a maximum-peak-period-demand charge, a maximum-part-peak-period demand charge, and a maximum-demand charge. The maximum-peak-period-demand charge per kilowatt applies to the maximum demand during the month's peak hours, the maximum-part-peak-demand charge applies to the maximum demand during the month's part-peak hours, and the maximum-demand charge per kilowatt applies to the maximum demand at any time during the month. The bill will include <u>all</u> of these demand charges. (Time periods are defined in Section 6.) (L) (T)

– As shown on the rate chart, which set of customer, demand, and energy charges is paid depends on the voltage at which service is taken. Service voltages are defined in Section 5 below. (T)

– Please note that the rates in the chart on the preceding page apply only to firm service. Rates for non-firm service can be found in Section 12 of this rate schedule.

b. AVERAGE RATE LIMITER (applies to bundled, firm service only): If the customer takes service on Schedule E-20, in either the secondary or primary voltage class, bills will be controlled by a "rate limiter" during the summer months. The bill will be reduced if necessary so that the average rate paid for all demand and energy charges less the Energy Rate Adjustment (ERA) amount calculated using the applicable rates provided in Schedule E-ERA during a summer month does not exceed the rate limiter shown on this schedule. This provision will not apply if the customer has elected to receive separate billing for back-up and maintenance service pursuant to Special Condition 8 of Schedule S.

Reductions in revenue resulting from application of the average rate limiter will be reflected as reduced distribution amounts for billing purposes. (L)

(L)

(Continued)

COMMERCIAL/INDUSTRIAL/GENERAL
SCHEDULE E-20—SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS OF 1,000 KILOWATTS OR MORE
(Continued)

3. FIRM SERVICE RATES: (Cont'd.)

c. PEAK-PERIOD RATE LIMITER (applies to bundled, firm service only): If the customer takes service on Schedule E-20 at any service voltage level, bills will be controlled by a "peak-period rate limiter" during the summer months. The bill will be reduced if necessary so that the average rate paid for all on-peak demand and energy charges less the peak period ERA amount calculated using the applicable rates provided in Schedule E-ERA during the peak period in a summer month does not exceed the peak-period rate limiter shown on this schedule. This provision will not apply if the customer has elected to receive separate billing for back-up and maintenance service pursuant to Special Condition 8 of Schedule S. (L)

Reductions in revenue resulting from application of the peak-period rate limiter will be reflected as reduced distribution amounts for billing purposes. (L)

4. METERING REQUIRE-MENTS:

An interval data meter that measures and registers the amount of electricity a customer uses and can be read remotely by PG&E is required for all customers on this schedule. A Meter Data Management Agent (MDMA) may also read the customer's meter on behalf of the customer's Energy Service Provider (ESP) if a customer is receiving Direct Access Service. (N)

For bundled service customers with maximum demands of 200 kW or greater for three consecutive months, PG&E will provide and install the interval data metering equipment at no cost to the customer and will waive any Time-Of-Use Installation or Time-Of-Use Processing charges for those customers who are initially required to be placed on a time-of-use schedule. The installation of an interval data meter for customers taking service under the provisions of Direct Access is the responsibility of the customer's Energy Service Provider, or their Agent, and must be installed in accordance with Electric Rule 22.

Customers who also request any meter data management services, must also sign an Interval Meter Data Management Service Agreement (Form 79-985) and must have an appropriate interval data meter. (N)

5. DEFINITION OF SERVICE VOLTAGE:

The following defines the three voltage classes of Schedule E-20 rates. Standard Service Voltages are listed in Rule 2. (T) (L)

a. Secondary: This is the voltage class if the service voltage is less than 2,400 volts or if the definitions of "primary" and "transmission" do not apply to the service.

b. Primary: This is the voltage class if the customer is served from a "single customer substation" or <u>without transformation</u> from PG&E's serving distribution system at one of the standard primary voltages specified in PG&E's Electric Rule 2, Section B.1.

c. Transmission: This is the voltage class if the customer is served <u>without transformation</u> at one of the standard transmission voltages specified in PG&E's Electric Rule 2, Section B.1. (L)

(Continued)

COMMERCIAL/INDUSTRIAL/GENERAL
SCHEDULE E-20—SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS OF 1,000 KILOWATTS OR MORE
(Continued)

6. DEFINITION OF TIME PERIODS:

Times of the year and times of the day are defined as follows:

SUMMER Period A (Service from May 1 through October 31):

Peak:	12:00 noon. to 6:00 p.m.	Monday through Friday (except holidays)
Partial-peak:	8:30 a.m. to 12:00 noon AND 6:00 p.m. to 9:30 p.m. Monday through Friday (except holidays).	
Off-peak:	9:30 p.m. to 8:30 a.m. All day	Monday through Friday Saturday, Sunday, and holidays

WINTER Period B (service from November 1 through April 30):

Partial-Peak:	8:30 a.m. to 9:30 p.m.	Monday through Friday (except holidays).
Off-Peak:	9:30 p.m. to 8:30 a.m. All day	Monday through Friday (except holidays). Saturday, Sunday, and holidays

HOLIDAYS: “Holidays” for the purposes of this rate schedule are New Year’s Day, President’s Day, Memorial Day, Independence Day, Labor Day, Veterans Day, Thanksgiving Day, and Christmas Day. The dates will be those on which the holidays are legally observed.

CHANGE FROM SUMMER TO WINTER OR WINTER TO SUMMER: When a billing month includes both summer and winter days, PG&E will calculate demand charges as follows. It will consider the applicable maximum demands for the summer and winter portions of the billing month separately, calculate a demand charge for each, and then apply the two according to the number of billing days each represents.

7. POWER FACTOR ADJUSTMENTS:

The bill will be adjusted based upon the power factor. The power factor is computed from the ratio of lagging reactive kilovolt-ampere-hours to the kilowatt-hours consumed in the month. Power factors are rounded to the nearest whole percent. (T) (L)

The rates in this rate schedule are based on a power factor of 85 percent. If the average power factor is greater than 85 percent, the total monthly bill will be reduced by 0.06 percent of the bundled service bill less any taxes and the ERA amount calculated using applicable rates provided in Schedule E-ERA for each percentage point above 85 percent. If the average power factor is below 85 percent, the total monthly bill will be increased by 0.06 percent of the bundled service bill less any taxes and the ERA amount calculated using applicable rates provided in Schedule E-ERA for each percentage point below 85 percent.

Power factor adjustments will be assigned to distribution for billing purposes. (L)

(Continued)

COMMERCIAL/INDUSTRIAL/GENERAL
SCHEDULE E-20—SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS OF 1,000 KILOWATTS OR MORE
(Continued)

(L)

8.	CHARGES FOR TRANSFORMER AND LINE LOSSES:	The demand and energy meter readings used in determining the charges will be adjusted to correct for transformation and line losses in accordance with Section B.4 of Rule 2.	(T)
9.	STANDARD SERVICE FACILITIES:	If PG&E must install any new or additional facilities to provide the customer with service under Schedule E-20, the customer may have to pay some of the cost. Any advance necessary and any monthly charge for the facilities will be specified in a line extension agreement. See Rules 2, 15, and 16 for details. Facilities installed to serve the customer may be removed when service is discontinued. The customer will then have to repay PG&E for all or some of its investment in the facilities. Terms and conditions for repayment will be set forth in the line extension agreement.	(T)
10.	SPECIAL FACILITIES:	PG&E will normally install only those standard facilities it deems necessary to provide service under Schedule E-20. If the customer requests any additional facilities, those facilities will be treated as “special facilities” in accordance with Section I of Rule 2.	(T)
11.	ARRANGEMENTS FOR VISUAL-DISPLAY METERING:	If the customer wishes to have visual-display metering equipment in addition to the regular metering equipment, and the customer would like PG&E to install that equipment, the customer must submit a written request to PG&E. PG&E will provide and install the equipment within 180 days of receiving the request. The visual-display metering equipment will be installed near the present metering equipment. The customer will be responsible for providing the required space and associated wiring. PG&E will continue to use the regular metering equipment for billing purposes.	(T)

(Continued)

COMMERCIAL/INDUSTRIAL/GENERAL
SCHEDULE E-20—SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS OF 1,000 KILOWATTS OR MORE
(Continued)

12. NON-FIRM SERVICE PROGRAM: As noted, the rates in the chart in Section 3 of this rate schedule apply to firm service only. ("Firm" means service where PG&E provides a "continuous and sufficient supply of electricity," as described in Rule 14.) Certain customers may also elect to receive non-firm service under Schedule E-20. (T)

In accordance with Decision 01-04-006, the Non-firm Service Program is closed to new or existing customers that are not currently in the program. Existing contracts may not be assigned to other parties. Customers considering participating in an interruptible program should refer to Schedule E-BIP for program terms and conditions, or may consider other available interruptible or demand response programs. The customer’s total load must meet the eligibility criteria in 11.a in order to participate in the Non-firm Service Program. Customers being served, as of December 31, 1992, under the Non-firm Service Program may continue to participate in the Non-firm Service Program.

This program is available for qualifying customers until modified or terminated in the rate design phase of the next general rate case or similar proceeding as ordered in Decision 02-04-060.

A customer who elects to receive non-firm service under Schedule E-20 must participate in PG&E's Emergency Curtailment Program. A non-firm service customer may also elect to participate in PG&E's Underfrequency Relay (UFR) Program.

EMERGENCY CURTAILMENT PROGRAM: Under the Emergency Curtailment Program, a non-firm service customer may be requested to reduce demand to a designated number of kilowatts (kW), referred to as the customer's contractual “firm service level.” PG&E will make requests for such curtailments from its non-firm service customers upon notification from the California Independent System Operator (ISO) that a system-wide or local operating condition exists which will impair the ability of the ISO to meet the demands of PG&E’s other customers. The ISO is expected to issue load curtailment directives to PG&E in those instances where load reductions are necessary in order to maintain system-wide operating reserves above the 5 percent level throughout the next operating hour, or if such load reductions are the sole remaining measure available in order to mitigate transmission overloads in the PG&E area.

(Continued)

COMMERCIAL/INDUSTRIAL/GENERAL
SCHEDULE E-20—SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS OF 1,000 KILOWATTS OR MORE
(Continued)

12. NON-FIRM SERVICE PROGRAM: (Cont'd.)

UNDERFREQUENCY RELAY PROGRAM: Under this program, the customer agrees to be subject at all times to automatic interruptions of service caused by an underfrequency relay device that may be installed by PG&E. (T)

Please note that PG&E may require up to three years' written notice for a change from non-firm to firm service, or for termination of participation in the Underfrequency Relay Program.

a. ELIGIBILITY CRITERIA FOR NON-FIRM SERVICE: To qualify for non-firm service, the customer must have had an average peak-period demand of at least 500 kW during each of the last six summer billing months prior to the customer's application for non-firm service. (Average peak-period demand is the total number of kWh used during the peak-period hours of a billing month divided by the total number of peak-period hours in the month.) Customers who have not yet had six months of summer service must demonstrate to PG&E's satisfaction that they will maintain an average monthly-peak-period demand of 500 kW or more to qualify for non-firm service.

Customers on non-firm service may not have, or obtain, any insurance for the sole 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. Eligibility for the non-firm program requires that each customer execute and submit to PG&E a No Insurance Declaration that states that the customer does not have, and will not obtain such insurance.

Customers who are deemed essential under the Electric Emergency Plan as adopted in Decision 01-04-006 and Rulemaking 00-10-002, must submit to PG&E a written declaration that states that the customer is, to the best of that customer's understanding, an essential customer under Commission rules and exempt from rotating outages. It must also state that the customer voluntarily elects to participate in an interruptible program for part 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)

COMMERCIAL/INDUSTRIAL/GENERAL
SCHEDULE E-20—SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS OF 1,000 KILOWATTS OR MORE
(Continued)

12. NON-FIRM SERVICE PROGRAM: (Cont'd.)

b. DESIGNATION OF FIRM SERVICE LEVEL: If a customer takes non-firm service, the designated number of kW to which the customer must reduce demand during emergency curtailments is the customer's contractual "firm service level." This designated firm service level must be at least 500 kW less than the smallest of the customer's average peak-period demands during the last six summer billing months prior to the designation. (T)

c. PRE-EMERGENCY CURTAILMENT REQUIREMENTS: A customer may be requested to curtail, on a pre-emergency basis, up to a maximum of two times per year (except that any emergency curtailments will count towards the maximum). Each pre-emergency curtailment will last no more than five hours. Customers will be given at least 30 minutes notice before each curtailment. The pre-emergency curtailments will be requested subject to the criteria listed in Section 12.d below, and PG&E's discretion. (T)

d. PRE-EMERGENCY CURTAILMENT PROCEDURE: PG&E will notify the customer by telephone, electronic mail, or other reliable means of communication. This notification will designate the time by which the customer's kW demand is requested to reduce to the customer's contractual firm service level. The notification will also designate the time when the customer may resume use of full power.

PG&E may call a pre-emergency curtailment if one of the following criteria are met:

1) The 9:00 a.m. forecast of temperatures in the Central Valley (the average of the forecasted temperature in Fresno and Sacramento) exceeds 100 degrees Fahrenheit; and PG&E has been informed by the ISO that an adjusted 10:00 a.m. forecast of two-hour reserves for that afternoon's peak is 12 percent or less; or

2) The 9:00 a.m. forecast of temperatures in the Central Valley exceeds 105 degrees Fahrenheit.

(Continued)

COMMERCIAL/INDUSTRIAL/GENERAL
SCHEDULE E-20—SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS OF 1,000 KILOWATTS OR MORE
(Continued)

12. NON-FIRM SERVICE PROGRAMS: (Cont'd.)

e. EMERGENCY CURTAILMENT PROCEDURE: When it becomes necessary for PG&E to request a curtailment, PG&E will notify the customer by telephone, electronic mail, or other reliable means of communication. This notification will designate a time by which the customer's kW demand is requested to be reduced to the customer's contractual firm service level. (T)

The customer is requested not to resume the use of curtailed power until notified by PG&E that it may do so or until the customer has curtailed its service for six hours.

f. LIMIT ON EMERGENCY CURTAILMENTS: The number of curtailment events will not exceed one (1) per day, four (4) in a calendar week, and thirty (30) times per calendar year. The duration of the curtailment events will not exceed six (6) hours each, forty (40) hours per calendar month, and a total of one hundred (100) hours per calendar year. The customer will be given at least 30 minutes notice before each curtailment.

Automatic UFR operations shall not be included in the annual pre-emergency or emergency curtailment limit.

g. EMERGENCY-NOTICE PROVISION: If there is an emergency on the PG&E system, PG&E may ask the customer to curtail the use of electricity on less than the 30 minute notice allowed for the Non-Firm Service Option. The customer will be asked to make its best effort to comply. The customer will not be assessed the noncompliance penalty for failing to comply within the shorter notice period.

The customer will be assessed a noncompliance penalty if the regular notice period for the operation passes and the customer still has not curtailed use.

(Continued)

COMMERCIAL/INDUSTRIAL/GENERAL
SCHEDULE E-20—SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS OF 1,000 KILOWATTS OR MORE
(Continued)

12. NON-FIRM SERVICE PROGRAM: (Cont'd.)

h. NONCOMPLIANCE PENALTY: (T)

The applicable noncompliance penalties are listed in Section 12. If a customer has curtailed to or below the designated firm service level for all of the requested pre-emergency and emergency curtailments, if any, in the preceding calendar year, the noncompliance penalty for the current year, will be the lower level shown in Section 13. (T)

The penalty will be calculated by determining the total amount of excess energy taken during the curtailment period (energy taken in excess of the customer's firm service level times the duration of the curtailment) and multiplying this total by the noncompliance penalty (per kWh).

Once a customer has complied with all the requested curtailments during the previous year, the customer's noncompliance penalty will remain at the reduced penalty level shown in Section 13 for the next calendar year. If the customer fails (T) to comply with a requested curtailment, the noncompliance penalty for the following year will be the higher value shown in Section 13. (T)

If no emergency or pre-emergency curtailments are called during a given year, the customer's noncompliance penalty for the next year in which curtailments occur shall be based on the customer's level of compliance during the last year curtailments were called.

During the year, PG&E will record any energy taken in excess of the customer's firm service level during any emergency or pre-emergency curtailments. PG&E will notify the customer of the amount of excess energy taken and the estimated noncompliance penalty. PG&E shall assess the noncompliance penalties, subject to the noncompliance penalty limit described below, at the end of the calendar year. The customer's noncompliance penalty shall be equal to the appropriate noncompliance penalty shown in Section 13 times the total amount of excess (T) energy taken during any pre-emergency and emergency curtailments.

In any given calendar year, the noncompliance penalties may not exceed 200 percent of the annual incentive level. The noncompliance penalty limit is equal to twice the annual incentive paid (the difference between what the customer would have paid on firm service rates less the customer's bill on non-firm rates excluding noncompliance penalties). If a customer's total noncompliance penalties in any given year exceed the noncompliance penalty limit, PG&E shall bill the customer a noncompliance penalty equal to the noncompliance penalty limit.

(Continued)

COMMERCIAL/INDUSTRIAL/GENERAL
SCHEDULE E-20—SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS OF 1,000 KILOWATTS OR MORE
(Continued)

12. NON-FIRM SERVICE PROGRAM: (Cont'd.)

i. ADDITIONAL NON-FIRM SERVICE PROVISIONS: (T)

1) **Required Re-Designations of Firm Service Level**: A non-firm service customer must maintain a difference of at least 500 kW between the firm service level and the average monthly summer peak-period demand. If the difference is less than 500 kW for any three summer months during any 12-month period, the customer must designate a new firm service level. This new firm service level must be at least 500 kW below the lowest of the customer's average peak-period demands for the last six summer billing months preceding the new designation. If the customer cannot meet this requirement, PG&E will change the account to firm service.

2) **Optional Re-Designations of Firm Service Level**: A non-firm service customer may decrease the firm service level effective with the start of any billing month, provided the customer gives PG&E at least 30 days' written notice. The customer may increase the firm service level (or return to full service) only with PG&E's permission or by giving PG&E three years notice, or by giving such notice to PG&E during a one-month period following any revisions of the program operating criteria initiated by the ISO, or during an annual contract review period that is provided for between November 1 and December 1 each year. The increased firm service level must be such that there is still at least a 500-kW difference between the firm service level and the lowest average monthly summer peak-period demand. The increased firm service level will become effective with the first regular reading of the meter after the customer receives permission from PG&E or at the end of the three year notice period. If a customer elects to change to firm service, they will not be permitted to subsequently return to non-firm status in the future.

3) **Telephone Line Requirements**: Non-firm customers are required to make available a telephone line and space for a notification printer. This requirement is in addition to any other equipment requirement which may apply.

j. BILL REDUCTIONS FOR NON-FIRM SERVICE CUSTOMERS:

1) **Demand Charges**: Reduced peak-period demand charges for curtailable service shall be applied to the difference between the customer's maximum demand in the peak-period and its Firm Service Level (but not less than zero). The peak-period charges for firm service shall be applied to the peak-period demand less the above difference.

2) **Energy Charges**: Reduced energy charges for curtailable service shall be applied to (a-b), where (a) is the number of kilowatt-hours used in the time period and (b) is the product of the Firm Service Level and the number of hours in the time period. (a-b) shall not be less than zero.

(Continued)

COMMERCIAL/INDUSTRIAL/GENERAL
SCHEDULE E-20—SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS OF 1,000 KILOWATTS OR MORE
(Continued)

12. NON-FIRM SERVICE PROGRAM: (Cont'd.)

k. PROVISIONS SPECIFIC TO UFR PROGRAM: (T)

1) **Details on Automatic Interruptions**: If a customer is participating in the UFR program, service to the customer will be automatically interrupted if the frequency on the PG&E system drops to 59.65 hertz for 20 cycles. PG&E will install and maintain a digital underfrequency relay and whatever associated equipment it believes is necessary to carry out such automatic interruption. Relays and other equipment will remain the property of PG&E. If more than one relay is required, PG&E will provide the additional relays as "special facilities," at customer's expense, in accordance with Section I of Rule 2.

   In addition to the underfrequency relay, PG&E may install equipment that would automatically interrupt service in case of voltage reductions or other operating conditions.

2) **Metering Requirements for UFR Program**: If a customer is participating in the UFR program under Schedule E-20 in combination with firm or curtailable-only service, the customer will be required to have a separate meter for the UFR service. PG&E will provide the meter sets, but the customer will be responsible for arranging customer's wiring in such a way that the service for each account can be provided and metered at a single point. NOTE: Any other additional facilities required for a combination of curtailable with firm service will be treated as "special facilities" in accordance with Section I of Rule 2.

3) **Communication Channel for UFR Service**: UFR program customers are required to provide an exclusive communication channel from the PG&E-provided terminal block at the customer's facility to a PG&E-designated control center. The communication channel must meet PG&E's specifications, and must be provided at the customer's expense. PG&E shall have the right to inspect the communication circuit upon reasonable notice.

(Continued)

COMMERCIAL/INDUSTRIAL/GENERAL
SCHEDULE E-20—SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS OF 1,000 KILOWATTS OR MORE
(Continued)

12. NON-FIRM SERVICE PROGRAM: (Cont'd.)

l. INTERACTIONS WITH OTHER DEMAND RESPONSE PROGRAMS: (T)

1. Customers who participate in a third-party sponsored interruptible load program must immediately notify PG&E of such activity.

2. Participants in the non-firm program may also participate in the Demand Bidding Program (Schedule E-DBP), but will not be paid the energy reduction incentives under the Schedule E-DBP during those hours where a non-firm event is issued.

3. Participants in the non-firm program may participate in the Optional Binding Mandatory Curtailment Program (Schedule E-OBMC) and the Pilot Optional Binding Mandatory Curtailment Program (Schedule E-POBMC) subject to meeting all applicable eligibility, operational and participation requirements specified in those schedules.

4. Participants in the non-firm program may participate in the Call Option of the California Power Authority Demand Reserves Partnership (CPA-DRP) program provided the additional load committed to the CPA-DRP is below their Firm Service Level (FSL) under the non-firm program. Participants in the non-firm program may participate in the Supplemental Energy Market Option of the CPA-DRP program, but will not be paid for curtailments under the California Power Authority's program during those hours when a non-firm event is issued. Participants in the non-firm program may not participate in the Ancillary Service Option of the CPA-DRP program.

5. Participants on the non-firm program shall not participate in the Scheduled Load Reduction Program (Schedule E-SLRP), or the Critical Peak Pricing Program (Schedule E-CPP) while on the non-firm program. Participants on the non-firm program may participate in the Base Interruptible Program (Schedule E-BIP) only after they have completed their annual obligations under the non-firm program.

(Continued)

COMMERCIAL/INDUSTRIAL/GENERAL
SCHEDULE E-20—SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS OF 1,000 KILOWATTS OR MORE
(Continued)

13. NON-FIRM SERVICE RATES:

These rates are applicable if the customer elects to take non-firm service. See Section 11 for an explanation of the non-firm service program and eligibility criteria.

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

TOTAL RATES

Total Customer Charge Rates	Secondary Voltage		Primary Voltage		Transmission Voltage	
Nonfirm Customer Charge ($ per meter per day)	$18.89117		$16.42710		$29.73306	
Nonfirm w/UFR Customer Charge ($ per meter per day)	$19.21971		$16.75564		$30.06160	
Optional Meter Data Access Charge	$ 0.98563		$ 0.98563		$ 0.98563	
Total Demand Rates ($ per kW)						
Maximum Peak Demand Summer	$5.50		$3.63		($0.62)	
Maximum Part-Peak Demand Summer	$3.11		$2.00		$0.05	
Maximum Demand Summer	$3.08		$3.09		$0.75	
Maximum Part-Peak Demand Winter	$3.06		$2.00		$0.19	
Maximum Demand Winter	$3.08		$3.09		$0.75	
Total Energy Rates ($ per kWh)						
Peak Summer	$0.13539	(I)	$0.10884	(I)	$0.10095	(I)
Part-Peak Summer	$0.08309	|	$0.07289	|	$0.06728	|
Off-Peak Summer	$0.07611	|	$0.07119	|	$0.06485	|
Part-Peak Winter	$0.08848	|	$0.08025	|	$0.07652	|
Off-Peak Winter	$0.07592	(I)	$0.07194	(I)	$0.06782	(I)
Noncompliance Penalty ($ per kWh per event)	$8.40		$8.40		$8.40	
Noncompliance Penalty ($ per kWh per event) (For customers who fully complied with the previous years operation)	$4.20		$4.20		$4.20	
UFR Credit ($ per kWh, if applicable)	$0.00091		$0.00091		$0.00091	

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

UNBUNDLING OF TOTAL RATES

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

Demand Rates by Component ($ per kW)	Secondary	Primary	Transmission
Generation:			
Maximum Peak Demand Summer	$7.07	$8.21	$6.88
Maximum Part-Peak Demand Summer	$1.95	$1.83	$0.55
Maximum Demand Summer	($3.68)	($2.62)	($3.87)
Maximum Part-Peak Demand Winter	$1.92	$1.83	$0.69
Maximum Demand Winter	($3.68)	($2.62)	($3.87)
Distribution:			
Maximum Peak Demand Summer	($1.57)	($4.58)	($7.50)
Maximum Part-Peak Demand Summer	$1.16	$0.17	($0.50)
Maximum Demand Summer	$2.14	$1.09	$0.00
Maximum Part-Peak Demand Winter	$1.14	$0.17	($0.50)
Maximum Demand Winter	$2.14	$1.09	$0.00
Transmission Maximum Demand*	$2.44	$2.44	$2.44
Reliability Services Maximum Demand*	$2.18	$2.18	$2.18

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

(Continued)

COMMERCIAL/INDUSTRIAL/GENERAL
SCHEDULE E-20— SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS OF 1,000 KILOWATTS OR MORE
(Continued)

13. NON-FIRM SERVICE RATES: (Cont'd.)

UNBUNDLING OF TOTAL RATES (Cont'd.)

Energy Rate by Components ($ per kWh)	Secondary Voltage	Primary Voltage	Transmission Voltage
Generation:			
Peak Summer	$0.11410	$0.09835	$0.09558
Part-Peak Summer	$0.05532	$0.05216	$0.05085
Off-Peak Summer	$0.04952	$0.05058	$0.04842
Part-Peak Winter	$0.05981	$0.05898	$0.06009
Off-Peak Winter	$0.04936	$0.05129	$0.05139
Distribution:			
Peak Summer	$0.00136	($0.00830)	($0.01220)
Part-Peak Summer	$0.00784	$0.00194	($0.00114)
Off-Peak Summer	$0.00666	$0.00182	($0.00114)
Part-Peak Winter	$0.00874	$0.00248	($0.00114)
Off-Peak Winter	$0.00663	$0.00186	($0.00114)
Noncompliance Penalty ($ per kWh per event)	$8.40	$8.40	$8.40
Noncompliance Penalty ($ per kWh per event) (For customers who fully complied with the previous years operation)	$4.20	$4.20	$4.20
UFR Credit ($ per kWh, if applicable)	$0.00091	$0.00091	$0.00091
Transmission Rate Adjustments* (all usage)	$0.00016	$0.00016	$0.00016
Public Purpose Programs (all usage)	$0.00454	$0.00402	$0.00326
Nuclear Decommissioning (all usage)	$0.00035	$0.00035	$0.00035
Competition Transition Charge (all usage)	$0.00434	$0.00372	$0.00326
Energy Cost Recovery Amount (all usage)	$0.00595 (I)	$0.00595 (I)	$0.00595 (I)
DWR Bond (all usage)	$0.00459	$0.00459	$0.00459

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

(Continued)

COMMERCIAL/INDUSTRIAL/GENERAL
SCHEDULE E-20—SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS OF 1,000 KILOWATTS OR MORE
(Continued)

14. CONTRACTS: STANDARD SERVICE AGREEMENT: To begin service under Schedule E-20, the customer shall be required to sign PG&E's Electric General Service Agreement (GSA). The GSA has an initial term of three (3) years. Once the three-year initial term is over, the agreement will automatically continue in effect for successive terms of one year each until it is cancelled. Customers may, at any time, request PG&E to modify the GSA if the service arrangements, electrical demand requirements, or delivery criteria to its premises change. However, customers will still be obligated to perform the terms and conditions outlined in any other agreements that supplement the GSA.

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

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

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

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

DA CRS	Secondary Voltage	Primary Voltage	Transmission Voltage
Energy Cost Recovery Amount Charge (per kWh)	$0.00595 (I)	$0.00595 (I)	$0.00595 (I)
DWR Power Charge (per kWh)	$0.01212 (R)	$0.01274 (R)	$0.01320 (R)
DWR Bond Charge (per kWh)	$0.00459	$0.00459	$0.00459
CTC Rate (per kWh)	$0.00434	$0.00372	$0.00326
Total DA CRS (per kWh)	$0.02700	$0.02700	$0.02700

CCA CRS	Secondary Voltage	Primary Voltage	Transmission Voltage
Energy Cost Recovery Amount Charge (per kWh)	$0.00595 (I)	$0.00595 (I)	$0.00595 (I)
DWR Power Charge (per kWh)	$0.01566	$0.01628	$0.01674
DWR Bond Charge (per kWh)	$0.00459	$0.00459	$0.00459
CTC Rate (per kWh)	$0.00434	$0.00372	$0.00326
Total CCA CRS (per kWh)	$0.03054 (I)	$0.03054 (I)	$0.03054 (I)

(Continued)

COMMERCIAL/INDUSTRIAL/GENERAL
SCHEDULE E-20—SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS OF 1,000 KILOWATTS OR MORE
(Continued)

17. OPTIONAL OPTIMAL BILLING PERIOD SERVICE: The Optimal Billing Period service is an experimental program that is limited to a maximum of 150 bundled service accounts at any one time. Customers electing this optional service must sign the Optimal Billing Service Customer Election Form (Standard Form 79-842). (T)

a. Eligibility

On an experimental pilot basis and subject to the availability and installation of solid state recorder equipment, firm service primary and secondary voltage customers whose maximum demand exceeds 1,000 kW for three consecutive billing months may select the “optimal billing period” service on a voluntary basis in up to two “subject” months (subject month is defined as the month in which the production cycle starts or ends), one at the start and one at the end of the customer’s high seasonal production cycle. The meter read date separating the subject month at the start of production, but precedes it at the end of production) would be redesignated to an alternative read date. In no event shall any revised billing period exceed 45 days nor less than 15 days. Where the start date is in a summer month, the summer season average rate limiter must otherwise apply to the subject month at the start of the customer’s high production cycle, but need not apply to the subject month at the end of production or the two adjacent months. The customer would retain the protection of the summer average rate limiter in all summer months, including the revised subject and adjacent months, where the rate limiter is imposed before the additional customer charge in Section 18.c has been included in the calculation.

To qualify, the duration of the customer’s high seasonal production period must be six (6) months or less, and the customer’s energy consumption during its high seasonal production cycle must be at least 2.0 times its consumption during its low seasonal production cycle for the most recent twelve (12) month period. Customers that discontinue this option may not enroll in this option again for a period of twelve (12) months. The customer must also specify which six (6) consecutive calendar months will be the optimal billing period. The optimal billing period must encompass the customer’s high seasonal production period.

(Continued)

COMMERCIAL/INDUSTRIAL/GENERAL
SCHEDULE E-20—SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS OF 1,000 KILOWATTS OR MORE
(Continued)

17. OPTIONAL OPTIMAL BILLING PERIOD SERVICE: (Cont'd.)

b. Customer Notification to PG&E (T)

Upon enrollment, the customer shall notify PG&E of the approximate two months where seasonal production starts and ends. As they occur, the customer shall notify PG&E of the exact seasonal production start and end dates. Upon notification by the customer of a production start date during a summer month, PG&E will wait until the regular read date to verify that the regular subject month bill would have otherwise invoked the rate limiter. If the rate limiter is invoked for the summer subject start month, the customer will be billed based on the optimal meter read dates or the regular scheduled meter read dates, whichever is the lower bill. Throughout the six month period, customers will receive their regular bill. Approximately two months after the production start or end date, the customer will receive a credit, if one should apply, for the optimal billing period. If a credit does not apply, the customer will not receive additional billing. If the rate limiter does not otherwise apply, the regular bill based on the old read date will be issued, and the customer can then request the special optimal bill option in only one production end date "subject" month. The application of this billing option to a production end date may occur prior to its application to a production start date, such as when a customer has more than one high production cycle. The customer must notify PG&E in writing, via facsimile (fax) to both the PG&E account representative and PG&E's Customer Billing Department, of the production start or end date within two days of the production start or end date. Customers will receive from PG&E's Customer Billing Department a fax receipt verification upon notice of a production start or end date. PG&E will notify the customer of the regularly scheduled meter read dates and, upon request, the customer's rate limiter history.

c. Customer Charge

Upon enrollment, a special customer charge will be assessed in all six (6) months in the optimal billing period to cover the incremental costs of the required solid state recorder, special program billing, recruitment, and administrative costs. The customer charge shall be $130 per meter per optimal billing period month for primary and secondary voltage customers. The customer is obligated to pay this monthly customer charge upon only while enrolled in this option, but any customer that drops out may not enroll in this option for a period of twelve (12) months. Customers who have signed contracts and are awaiting solid state recorders so that they can participate in the program will not be assessed the special customer charge until a solid state recorder has been installed.

For billing purposes, the special customer charge for the optional billing period service shall be assigned to Distribution.

(Continued)

COMMERCIAL/INDUSTRIAL/GENERAL
SCHEDULE E-20—SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS OF 1,000 KILOWATTS OR MORE
(Continued)

17. OPTIONAL OPTIMAL BILLING PERIOD SERVICE: (Cont'd.)

d. Proration of Charges (T)

All applicable customer charges, demand charges or other applicable fixed charges, shall be prorated as specified in Rule 9. As specified in Rule 9, Sections A and B, the regular billing period will be once each month, and prorations for monthly bills of less than 27 or more than 33 days shall be calculated on the basis of the number of days in the period in question to the total number of days in an average month, as specified in Rule 9.

e. Functional Assignment of Credit

For billing purposes, the optional billing credit will be assigned to Distribution.

18. ELECTRIC EMER-GENCY PLAN ROTATING BLOCK OUTAGES:

As set forth in CPUC Decision 01-04-006, all transmission level customers except essential use customers, OBMC participants, net suppliers to the electrical grid, or others exempt by the Commission, are to be included in rotating outages in the event of an emergency. A transmission level customer who refuses or fails to drop load shall be added to the next rotating outage group so that the customer does not escape curtailment. If the transmission level customer fails to cooperate and drop load at PG&E's request, automatic equipment controlled by PG&E will be installed at the customer's expense per Electric Rule 2. A transmission level customer who refuses to drop load before installation of the equipment shall be subject to a penalty of $6/kWh for all load requested to be curtailed that is not curtailed. The $6/kWh penalty shall not apply if the customer's generation suffers a verified, forced outage and during times of scheduled maintenance. The scheduled maintenance must be approved by both the ISO and PG&E, but approval may not be unreasonably withheld. (T)

19. STANDBY APPLICA-BILITY:

SOLAR GENERATION FACILITIES EXEMPTION: Customers who utilize solar generating facilities which are less than or equal to one megawatt to serve load and who do not sell power or make more than incidental export of power into PG&E's power grid and who have not elected service under Schedule NEM, will be exempt from paying the otherwise applicable standby reservation charges. (T) (T)

DISTRIBUTED ENERGY RESOURCES EXEMPTION: Any customer under a time-of-use rate schedule using electric generation technology that meets the criteria as defined in Electric Rule 1 for Distributed Energy Resources is exempt from the otherwise applicable standby reservation charges. Customers qualifying for this exemption shall be subject to the following requirements. Customers qualifying for an exemption from standby charges under Public Utilities (PU) Code Sections 353.1 and 353.3, as described above, must take service on a time-of-use (TOU) schedule in order to receive this exemption until a real-time pricing program, as described in PU Code 353.3, is made available. Once available, customers qualifying for the standby charge exemption must participate in the real-time program referred to above. Qualification for and receipt of this distributed energy resources exemption does not exempt the customer from metering charges applicable to time-of-use (TOU) and real-time pricing, or exempt the customer from reasonable interconnection charges, non-bypassable charges as required in Preliminary Statement BB - *Competition Transition Charge Responsibility for All Customers and CTC Procurement*, or obligations determined by the Commission to result from participation in the purchase of power through the California Department of Water Resources, as provided in PU Code Section 353.7.

(Continued)

COMMERCIAL/INDUSTRIAL/GENERAL
SCHEDULE E-20—SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS OF 1,000 KILOWATTS OR MORE
(Continued)

20. DWR BOND CHARGE: The Department of Water Resources (DWR) Bond Charge was imposed by California Public Utilities Commission Decision 02-10-063, as modified by Decision 02-12-082, and is property of DWR for all purposes under California law. The Bond Charge applies to all retail sales, excluding CARE and Medical Baseline sales. The DWR Bond Charge (where applicable) is included in customers' total billed amounts. (T)

Schedule I-6 Sheet 1

TIME-OF-USE

GENERAL SERVICE - LARGE - INTERRUPTIBLE

APPLICABILITY

This Schedule is optional for customers eligible for service under Schedule TOU-8, General Service - Large. As of November 26, 1996, this Schedule is closed except that existing customers adding new load can qualify for this Schedule with a Firm Service Level no less than their Maximum Demand in the preceding 12 months. Customers newly taking service from SCE can take service under this Schedule for electrical loads not previously served by SCE.

TERRITORY

Within the entire territory served.

RATES

The following rates are set forth for service metered and delivered at secondary, primary, and subtransmission voltages.

A charge for Excess Energy may apply under certain conditions, as provided in Special Condition 8.

Applicable Schedule Charges:

All charges and provisions of Schedule TOU-8 shall apply, except Special Condition 10, and except that the interruptible portion of the customer's energy and demand, as set forth in Special Condition 4 below, shall be charged as follows:

SERVICE METERED AND DELIVERED AT VOLTAGES BELOW 2 KV

	Delivery Service							Gen[8]	
	Trans[1]	Distrbtn[2]	NDC[3]	PPPC[4]	PUCRF[5]	DWRBC[6]	Total[7]	URG*	DWR
Energy Charge - $/kWh/Meter/Month									
Summer Season – On-Peak	0.00153 (I)	(0.00814)	0.00054	0.00518	0.00000	0.00459	0.00370 (I)	0.11736	0.07981
Mid-Peak	0.00153 (I)	(0.00593)	0.00054	0.00518	0.00000	0.00459	0.00591 (I)	0.04938	0.07981
Off-Peak	0.00153 (I)	(0.00227)	0.00054	0.00518	0.00000	0.00459	0.00957 (I)	0.00701	0.07981
Winter Season – On-Peak	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Mid-Peak	0.00153 (I)	(0.00619)	0.00054	0.00518	0.00000	0.00459	0.00565 (I)	0.07556	0.07981
Off-Peak	0.00153 (I)	(0.00197)	0.00054	0.00518	0.00000	0.00459	0.00987 (I)	0.00927	0.07981
Demand Charge-$/kW of Billing Demand/Meter/Month									
Time Related									
Summer Season – On-Peak		3.88					3.88	15.93	
Mid-Peak		0.06					0.06	3.30	
Off-Peak		0.00					0.00	0.00	
Winter Season – On-Peak		N/A					N/A	N/A	
Mid-Peak		0.00					0.00	0.00	
Off-Peak		0.00					0.00	0.00	
Excess Energy Charge - $/kWh		10.64895					10.64895		

(Continued)

Schedule I-6 Sheet 2
TIME-OF-USE
GENERAL SERVICE - LARGE - INTERRUPTIBLE
(Continued)

RATES (Continued)

SERVICE METERED AND DELIVERED AT VOLTAGES BELOW 2 KV (Continued)

Delivery Service							Gen[8]	
Trans[1]	Distrbtn[2]	NDC[3]	PPPC[4]	PUCRF[5]	DWRBC[6]	Total[7]	URG*	DWR

* The ongoing Competition Transition Charge (CTC) of $0.00028 is recovered in the URG component in Generation.
1 Trans = Transmission and the Transmission Owners Tariff Charge Adjustments (TOTCA) which are FERC approved. The TOTCA represents the Transmission Revenue Balancing Account Adjustment (TRBAA) of negative $0.00089 per kWh, Reliability Services Balancing Account Adjustment (RSBAA) of $0.00168 per kWh, and Transmission Access Charge Balancing Account Adjustment (TACBAA) of $0.00074 per kWh. (I)
2 Distrbtn = Distribution
3 NDC = Nuclear Decommissioning Charge
4 PPPC = Public Purpose Programs Charge (includes California Alternate Rates for Energy Surcharge where applicable.)
5 PUCRF = The PUC Reimbursement Fee is described in Schedule RF-E.
6 DWRBC = Department of Water Resources (DWR) Bond Charge. The DWR Bond Charge is not applicable to exempt Bundled Service and Direct Access Customers, as defined in and pursuant to D.02-10-063, D.02-02-051,and D.02-12-082.
7 Total = Total Delivery Service rates are applicable to Bundled Service, Direct Access (DA) and Community Choice Aggregation (CCA) customers, except DA and CCA customers are not subject to the DWRBC rate component of this Schedule but instead pay the DWRBC as provided by Schedule DA-CRS or Schedule CCA-CRS.
8 Gen = Generation – The Gen rates are applicable only to Bundled Service Customers. When calculating the Energy Charge, the Gen portion is calculated as described in the Billing Calculation Special Condition of this Schedule.

SERVICE METERED AND DELIVERED AT VOLTAGES FROM 2 KV THROUGH 50 KV

	Delivery Service							Gen[8]	
	Trans[1]	Distrbtn[2]	NDC[3]	PPPC[4]	PUCRF[5]	DWRBC[6]	Total[7]	URG*	DWR
Energy Charge - $/kWh/Meter/Month									
Summer Season – On-Peak	0.00131 (I)	(0.00771)	0.00054	0.00500	0.00000	0.00459	0.00373 (I)	0.12419	0.07981
Mid-Peak	0.00131 (I)	(0.00619)	0.00054	0.00500	0.00000	0.00459	0.00525 (I)	0.05280	0.07981
Off-Peak	0.00131 (I)	(0.00340)	0.00054	0.00500	0.00000	0.00459	0.00804 (I)	0.01110	0.07981
Winter Season – On-Peak	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Mid-Peak	0.00131 (I)	(0.00618)	0.00054	0.00500	0.00000	0.00459	0.00526 (I)	0.07725	0.07981
Off-Peak	0.00131 (I)	(0.00311)	0.00054	0.00500	0.00000	0.00459	0.00833 (I)	0.01341	0.07981
Demand Charge-$/kW of Billing Demand/Meter/Month									
Time Related									
Summer Season – On-Peak		3.06					3.06	16.94	
Mid-Peak		(0.01)					(0.01)	3.28	
Off-Peak		0.00					0.00	0.00	
Winter Season – On-Peak		N/A					N/A	N/A	
Mid-Peak		0.00					0.00	0.00	
Off-Peak		0.00					0.00	0.00	
Excess Energy Charge - $/kWh		10.42129					10.42129		

(Continued)

Schedule I-6 Sheet 3
TIME-OF-USE
GENERAL SERVICE - LARGE - INTERRUPTIBLE
(Continued)

RATES (Continued)

SERVICE METERED AND DELIVERED AT VOLTAGES FROM 2 KV THROUGH 50 KV (Continued)

Delivery Service							Gen[8]	
Trans[1]	Distrbtn[2]	NDC[3]	PPPC[4]	PUCRF[5]	DWRBC[6]	Total[7]	URG*	DWR

* The ongoing Competition Transition Charge (CTC) of $0.00026 is recovered in the URG component of Generation.

1 Trans = Transmission and the Transmission Owners Tariff Charge Adjustments (TOTCA) which are FERC approved. The TOTCA represents the Transmission Revenue Balancing Account Adjustment (TRBAA) of negative $0.00089 per kWh, Reliability Services Balancing Account Adjustment (RSBAA) of $0.00146 per kWh, and Transmission Access Charge Balancing Account Adjustment (TACBAA) of $0.000074 per kWh. (I)

2 Distrbtn = Distribution

3 NDC = Nuclear Decommissioning Charge

4 PPPC = Public Purpose Programs Charge (includes California Alternate Rates for Energy Surcharge where applicable.)

5 PUCRF = The PUC Reimbursement Fee is described in Schedule RF-E.

6 DWRBC = Department of Water Resources (DWR) Bond Charge. The DWR Bond Charge is not applicable to exempt Bundled Service and Direct Access Customers, as defined in and pursuant to D.02-10-063, D.02-02-051, and D.02-12-082.

7 Total = Total Delivery Service rates are applicable to Bundled Service, Direct Access (DA) and Community Choice Aggregation (CCA) customers, except DA and CCA customers are not subject to the DWRBC rate component of this Schedule but instead pay the DWRBC as provided by Schedule DA-CRS or Schedule CCA-CRS.

8 Gen = Generation – The Gen rates are applicable only to Bundled Service Customers. When calculating the Energy Charge, the Gen portion is calculated as described in the Billing Calculation Special Condition of this Schedule.

SERVICE METERED AND DELIVERED AT VOLTAGES ABOVE 50 KV

	Delivery Service							Gen[8]	
	Trans[1]	Distrbtn[2]	NDC[3]	PPPC[4]	PUCRF[5]	DWRBC[6]	Total[7]	URG*	DWR
Energy Charge - $/kWh/Meter/Month									
Summer Season – On-Peak	0.00115 (I)	(0.00753)	0.00054	0.00415	0.00000	0.00459	0.00290 (I)	0.09752	0.07981
Mid-Peak	0.00115 (I)	(0.00690)	0.00054	0.00415	0.00000	0.00459	0.00353 (I)	0.04656	0.07981
Off-Peak	0.00115 (I)	(0.00538)	0.00054	0.00415	0.00000	0.00459	0.00505 (I)	0.01834	0.07981
Winter Season – On-Peak	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Mid-Peak	0.00115 (I)	(0.00720)	0.00054	0.00415	0.00000	0.00459	0.00323 (I)	0.06916	0.07981
Off-Peak	0.00115 (I)	(0.00533)	0.00054	0.00415	0.00000	0.00459	0.00510 (I)	0.02089	0.07981
Demand Charge-$/kW of Billing Demand/Meter/Month									
Time Related									
Summer Season – On-Peak		0.84					0.84	14.93	
Mid-Peak		(0.12)					(0.12)	2.88	
Off-Peak		0.00					0.00	0.00	
Winter Season – On-Peak		N/A					N/A	N/A	
Mid-Peak		0.00					0.00	0.00	
Off-Peak		0.00					0.00	0.00	
Excess Energy Charge - $/kWh		10.05518					10.05518		

(Continued)

Schedule I-6
TIME-OF-USE
GENERAL SERVICE - LARGE - INTERRUPTIBLE
(Continued)

Sheet 4

RATES (Continued)

SERVICE METERED AND DELIVERED AT VOLTAGES ABOVE 50 KV (Continued)

Delivery Service							Gen[8]	
Trans[1]	Distrbtn[2]	NDC[3]	PPPC[4]	PUCRF[5]	DWRBC[6]	Total[7]	URG*	DWR

* The ongoing Competition Transition Charge (CTC) of $0.00021 is recovered in the URG component of Generation.
1 Trans = Transmission and the Transmission Owners Tariff Charge Adjustments (TOTCA) which are FERC approved. The TOTCA represents the Transmission Revenue Balancing Account Adjustment (TRBAA) of negative $0.00089 per kWh, Reliability Services Balancing Account Adjustment (RSBAA) of $0.00130 per kWh, and Transmission Access Charge Balancing Account Adjustment (TACBAA) of $0.00074 per kWh. (I)
2 Distrbtn = Distribution
3 NDC = Nuclear Decommissioning Charge
4 PPPC = Public Purpose Programs Charge (includes California Alternate Rates for Energy Surcharge where applicable.)
5 PUCRF = The PUC Reimbursement Fee is described in Schedule RF-E.
6 DWRBC = Department of Water Resources (DWR) Bond Charge. The DWR Bond Charge is not applicable to exempt Bundled Service and Direct Access Customers, as defined in and pursuant to D.02-10-063, D.02-02-051,and D.02-12-082.
7 Total = Total Delivery Service rates are applicable to Bundled Service, Direct Access (DA) and Community Choice Aggregation (CCA) customers, except DA and CCA customers are not subject to the DWRBC rate component of this Schedule but instead pay the DWRBC as provided by Schedule DA-CRS or Schedule CCA-CRS.
8 Gen = Generation – The Gen rates are applicable only to Bundled Service Customers. When calculating the Energy Charge, the Gen portion is calculated as described in the Billing Calculation Special Condition of this Schedule.

(Continued)

Schedule I-6 Sheet 5
TIME-OF-USE
GENERAL SERVICE - LARGE - INTERRUPTIBLE
(Continued)

SPECIAL CONDITIONS

1. Maximum Demand: Maximum demands shall be established for the On-Peak, Mid-Peak, and Off-Peak Time Periods. The maximum demand for each period shall be the measured maximum average kilowatt input indicated or recorded by instruments , during any 15-minute metered interval in the month. Where the demand is intermittent or subject to violent fluctuations, a 5-minute interval may be used.

2. Interruptible Load: The Interruptible Load is the estimated increment of the customer's Maximum Demand that normally occurs above the Firm Service Level and, under normal operating conditions, would be the amount of load to be disconnected from SCE's lines within the specified time period following Notice of Interruption.

3. Firm Service Level: Firm Service Level is the Maximum Demand SCE is expected to supply and/or deliver during any Period of Interruption. The Firm Service Level shall be specified by the customer. During a Period of Interruption, the customer is expected to interrupt load to its specified Firm Service Level. Increases or decreases in Firm Service Level may be made no more often than once per year, upon written request by the customer between November 1 and December 1 and execution of an Amendment To Contract For Interruptible Service (Form 14-332). Customers served under this Schedule shall establish a Firm Service Level of zero or greater.

4. Interruptible Demand and Energy: Interruptible Demand is all kW of Maximum Demand in excess of the Firm Service Level. Interruptible Energy is the number of kWh in each Time Period which exceeds the product of the Firm Service Level kW multiplied by the total number of hours in the Time Period.

5. Notice of Interruption: Upon notification to SCE from the Independent System Operator (ISO) (T)
of the need to implement load reductions in SCE's service territory, a Notice of Interruption |
can be given under this Schedule. SCE shall notify the customer to reduce the demand |
imposed on the electric system to the Firm Service Level. Upon receipt by a customer of a |
Notice of Interruption from SCE, the customer shall reduce the demand imposed on the (T)
electric system to the Firm Service Level within 30 minutes.

6. Period of Interruption: A Period of Interruption is a time interval which commences thirty minutes after Notice of Interruption and which ends upon notification by SCE of the end of Period of Interruption.

(Continued)

Schedule I-6
TIME-OF-USE
GENERAL SERVICE - LARGE - INTERRUPTIBLE
(Continued)

Sheet 6

SPECIAL CONDITIONS (Continued)

7. Excess Energy: The number of kWh consumed in each Time Period involved in a Period of Interruption which exceeds the product of the Firm Service Level kW multiplied by the total number of hours of Interruption within the Time Period, shall be considered Excess Energy.

8. Charges for Excess Energy: For each period of interruption during which the customer fails to interrupt and hence incurs Excess Energy, the applicable $/kWh penalty as shown in the Rates section of this Schedule, shall be added to the customer's billing as otherwise provided in this Schedule.

9. Ownership and Control of Facilities: Communication, metering, and interrupting facilities, as specified by SCE, will be installed, owned, and maintained in accordance with SCE specifications at customer's expense, including such facilities not located on the customer's property. These facilities will be solely under operational control of SCE unless otherwise specified by SCE.

   Such communications and interrupting facilities may include, but will not be limited to, the following:

   a. Necessary facilities between the customer and SCE to provide Notice of Interruption.

   b. Equipment to permit remote monitoring of the customer's load.

(D)

(Continued)

Schedule I-6 Sheet 7
TIME-OF-USE
GENERAL SERVICE - LARGE - INTERRUPTIBLE
(Continued)

SPECIAL CONDITIONS (Continued)

10. Contracts: A contract is required for service under this Schedule. To be served under this Schedule, eligible customers shall comply with all provisions of the contract within 30 days of contract execution. Customers shall have a one month window each year between November 1 and December 1, to provide written notice to SCE to terminate service or to increase or decrease their Firm Service Level under this Schedule. Additionally, during this one month window, a customer receiving service concurrently under both this Schedule and under Schedule TOU-BIP may select which Schedule under which it shall receive service (T) during the following year. If no selection is made, the customer shall continue service under this Schedule and service under Schedule TOU-BIP shall be terminated as of January 1 of (T) the next calendar year. Customers shall not be permitted to prematurely terminate service hereunder for reasons that changes in electrical demand requirements may otherwise preclude them from taking service under this Schedule. Customers permitted by SCE to change to this Schedule from another interruptible schedule shall, without further action by SCE, retain the termination requirements, if any, of the prior schedule and any contract associated therewith.

11. Number and Duration of Interruption: The number of Periods of Interruption will not exceed one (1) per day, four (4) in any calendar week, and 25 times per calendar year. The duration of the Periods of Interruption will not exceed 6 hours each, 40 hours per calendar month, and a total of 150 hours per calendar year.

12. Relationship to Other Programs. Load can only be committed to one program, and participants paid only once for a load reduction. With limitations, participants in I-6 may also participate in TOU-BIP, Demand Bidding Program (Schedule DBP), and the California Power (T) Authority Demand Reserves Partnership Program (CPA DRP). Customers enrolled in DBP or the CPA DRP Supplemental Energy Market option will not receive an incentive payment during hours where there is an overlapping I-6 event. Customers may participate in the CPA-DRP reservation payment options provided their CPA-DRP interruptible load is below their I-6 Firm Service Level. In addition, Customers on this Schedule shall not participate in the ISO's Ancillary Services Load Program.

(Continued)

Schedule I-6 — Sheet 8

TIME-OF-USE

GENERAL SERVICE - LARGE - INTERRUPTIBLE

(Continued)

SPECIAL CONDITIONS (Continued)

13. Customer-Owned Electrical Generating Facilities:

    a. Where customer-owned electrical generating facilities are used to meet a part or all of the customer's electrical requirements, service shall be provided concurrently under the terms and conditions of Schedule S and this Schedule. Parallel operation of such generating facilities with SCE's electrical system is permitted. A generation interconnection agreement is required for such operation.

    b. Customer-owned electrical generating facilities used solely for auxiliary, emergency, or standby purposes (auxiliary/emergency generating facilities) to serve the customer's load during a period when SCE's service is unavailable and when such load is isolated from the service of SCE are not subject to Schedule S. However, upon approval by SCE, momentary parallel operation may be permitted in order for the customer to avoid interruption of load during a Period of Interruption or to allow the customer to test the auxiliary/emergency generating facilities. A Momentary Parallel Generation Contract is required for this type of service.

(D)

(Continued)

Schedule I-6 Sheet 9
TIME-OF-USE
GENERAL SERVICE - LARGE - INTERRUPTIBLE
(Continued)

SPECIAL CONDITIONS (Continued)

14. Experimental Interruptible Load Aggregation Option: This Special Condition is applicable to customers served under this Schedule with one or more additional Service Accounts served under this Schedule or one of SCE's other general service large interruptible Schedules. Under this Special Condition, when a Notice of Interruption is given, the customer may use the Aggregate Interruptible Load of such multiple interruptible Service Accounts to meet the customer's load interruption obligation. The customer may select which Service Account(s) will be interrupted during an Interruptible Event rather than have to interrupt the load of the specific Service Account for which the Notice of Interruption was given by SCE. Service under this Special Condition is subject to the installation of SCE's metering and associated facilities which are required to take interruptible service. (T)

If the customer desires real-time, two-way (interactive) communication of interruptible load information and customer load data, at the customer's option SCE may install, own, operate, and maintain metering capable of recording and providing hourly data and telemetry and annunciation facilities capable of such communication on each Service Account. Such Company facilities are installed at the customer's expense in accordance with the provisions of Rule 2, Section H or J, as applicable, for which a contract is required. The customer shall provide and own any necessary facilities, as determined by SCE, capable of interfacing with SCE's facilities installed for this purpose. When the customer elects to have service under this Special Condition provided in this manner, such service is subject to the availability and installation of SCE's facilities and the installation of the customer's facilities.

An agreement is required to take service under this Special Condition and customers are subject to a one-time charge of $50.00 per agreement. The agreement includes a list of the Service Accounts served under this Special Condition and it supplements each Service Account's Contract for Interruptible Service. Service under the Special Condition shall be for two years and will renew in two year increments, but may be terminated at any time by the customer or SCE upon twelve (12) months written notice. This Special Condition is closed to new customers when 20 Experimental Interruptible Load Aggregation Option Agreements are served under this option or when SCE determines that the total load served under all such agreements exceeds 200 MW.

A customer receiving service under this Special Condition who has fulfilled its interruption obligations and who elects to receive service under Schedule TOU-BIP may receive such service in conjunction with the terms and conditions of this Special Condition. Additionally, a customer receiving service under this Special Condition may receive service under Schedule DBP. (T)

15. Noncompliance: The customer's noncompliance with any of the terms and/or conditions of this Schedule and/or the associated contract(s), except for the terms and conditions relating to failure to interrupt load, may result in the suspension of the use of the demand and energy charges of this Schedule, which reflect the interruptible credit, to calculate the customer's bill. In such situations, the demand and energy charges of the non-complying customer's otherwise applicable standard Schedule may be used for billing purposes. However, the non-complying customer remains subject to all other terms and conditions of this Schedule and the applicable contract(s). The demand and energy charges of this rate schedule may again be applicable to the customer's bills for service rendered after the next regular meter reading following the date SCE determines the customer is in compliance. (T)

(Continued)

Schedule I-6 Sheet 10
TIME-OF-USE
GENERAL SERVICE - LARGE - INTERRUPTIBLE
(Continued)

SPECIAL CONDITIONS (Continued)

16. Direct Access (DA) and Community Choice Aggregation (CCA): A customer receiving DA or CCA service shall notify its Energy Service Provider (ESP) or Community Choice Provider (CCP), as applicable, and Scheduling Coordinator that it is subject to interruption under this Schedule. In addition, if a DA or CCA customer receiving owns its own meter or has a meter provided by an ESP or CCP, the meter must be capable of providing the proper pulse data interface between the customer's metering system, SCE's data recorder, and SCE's remote terminal unit (RTU). (T)

17. Billing Calculation: A customer's bill is calculated according to the rates and conditions above. (T)

    Except for the Energy Charge, the charges listed in the Rates section are calculated by multiplying the Total Delivery Service rates and the Generation rates, when applicable, by the billing determinants (e.g., per kilowatt [kW], kilowatthour [kWh], kilovar [kVa] etc.),

    The Energy Charge, however, is determined by multiplying the total kWhs by the Total Delivery Service per kWh rates to calculate the Delivery Service amount of the Charge. To calculate the Generation amount, SCE determines what portion of the total kWhs is supplied by the Utility Retained Generation (URG) and the Department of Water Resources (DWR). The kWhs supplied by the URG are multiplied by the URG per kWh rates and the kWhs supplied by the DWR are multiplied by the DWR per kWh rate and the two products are summed to arrive at the Generation amount. The Energy Charge is the sum of the Delivery Service amount and the Generation amount.

    For each billing period, SCE determines the portion of total kWhs supplied by SCE's URG and by the DWR. This determination is made by averaging the daily percentages of energy supplied to SCE's Bundled Service Customers by SCE's URG and by the DWR.

    a. Bundled Service Customers receive Delivery Service from SCE and receive supply (Gen) service from both SCE's URG and the DWR. The customer's bill is the sum of the charges for Delivery Service and Gen determined, as described in this Special Condition, and subject to applicable discounts or adjustments provided under SCE's tariff schedules.

    b. Direct Access Customers receive Delivery Service from SCE and purchase energy from an Energy Service Provider. The customer's bill is the sum of the charges for Delivery Service determined as described in this Special Condition except that the DWRBC rate component is subtracted from the Total Delivery Service rates before the billing determinants are multiplied by such resulting Total rates; plus the applicable charges as shown in Schedule DA and subject to applicable discounts or adjustments provided under SCE's tariff schedules.

(L) (D)

    c. Community Choice Aggregation (CCA) customers receive Delivery Service from SCE and purchase energy from their Community Choice Provider (CCP). SCE will read the meters and present the bill for both Delivery and Generation Services to the CCA customer. The customer's bill is the sum of the charges for Delivery Service as displayed in this Rate Schedule and Generation charges determined by the CCP plus the applicable charges as shown in Schedule CCA-CRS, and subject to applicable discounts or adjustments provided under SCE's tariff schedules.

(Continued)

Schedule I-6 Sheet 11
TIME-OF-USE
GENERAL SERVICE - LARGE - INTERRUPTIBLE
(Continued)

SPECIAL CONDITIONS (Continued)

18. Insurance. Insurance may not be used to pay non-compliance penalties for willful failure to comply with a Notice of Interruption. Existing and new customers will not be eligible for continued service or new service under this Schedule unless a declaration is signed under penalty of perjury which states that the customer does not have, and will not obtain, any insurance for the purpose of the insurance paying non-compliance penalties for willful failure to comply with Notices of Interruptions. Continuing eligibility and new eligibility under this Schedule will require that each customer execute a declaration stating that it does not have, and will not obtain, such insurance. For any customer with such insurance after the effective date of this Special Condition, service under this Schedule will be terminated and such customer will be required to pay back the interruptible rate discounts 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 this Schedule. (T)

19. Essential Use Customers. Customers receiving service under this Schedule and who are classified as Essential Use in accordance with Commission Decision No. 91548 must provide proof of adequate back-up generation or other means to supply energy for interruptible load. A declaration must be signed under penalty of perjury and must state that the customer is, to the best of that customer's understanding, an Essential Use customer under Commission rules. It must also state that the customer voluntarily elects to participate in an interruptible program for part of or all of its load upon request by SCE, while continuing to meet its essential needs based on adequate backup generation or other means. Furthermore, such customer must adjust its Firm Service Level to equal no less than 50 percent its load. Customer must sign an Amendment to Contract for Interruptible Service (Form 14-332). Absent such declaration and absent an execution of Form 14-332, if applicable, SCE may find the customer ineligible to receive service under this Schedule. (T)

(D)

(Continued)

Schedule I-6
TIME-OF-USE
GENERAL SERVICE - LARGE - INTERRUPTIBLE
(Continued)

Sheet 12

SPECIAL CONDITIONS (Continued)

20. Customers with Service Metered and Delivered at Voltages above 50 kV (Sub-transmission customers) Included in Rotating Outages. (T)

Sub-transmission customers, except for those customers exempt from rotating outages, are to be included in controlled, rotating outages when required by the Independent System Operator (ISO). To the extent feasible, SCE will coordinate rotating outages applicable to Sub-transmission customers who are fossil fuel producers and pipeline operators and users to minimize disruption to public health and safety. SCE shall not include a Sub-transmission customer in an applicable rotating outage group if the customer’s inclusion would jeopardize electric system integrity. Sub-transmission customers who are not exempt from rotating outages, and seek such exemption, may submit an Optional Binding Mandatory Curtailment (OBMC) Plan to SCE in accordance with Schedule OBMC. If SCE approves a customer’s OBMC Plan, the customer will become exempt from rotating outages and will be subject to the terms and conditions of Schedule OBMC and its associated contract.

Non-exempt Sub-transmission customers shall be required to drop their entire electrical load during applicable rotating outages by either (1) implementing the load reduction on their own initiative, in accordance with subsection a, below; or (2) having SCE implement the load reduction through remote-controlled load drop equipment (control equipment) in accordance with subsection b, below. A Sub-transmission customer shall normally be subject to the provisions of subsection a. If SCE approves a customer’s request to have SCE implement the load reduction or if the customer does not comply with prior required load reductions, as specified in subsection c, the customer will be subject to the provisions of subsection b.

a. Customer-Implemented Load Reduction.

(i) Notification of Required Load Reduction. At the direction of the ISO, SCE shall notify each Sub-transmission customer in an affected rotating outage group to drop its entire load. Within 30 minutes of such notification, the customer must drop its entire load. The customer shall not return the dropped load to service until 90 minutes after SCE sent the notification to the customer to drop its load, unless SCE notifies the customer that it may return its load to service prior to the expiration of the 90 minutes.

(ii) Method of Notification. SCE will notify Sub-transmission customers who are required to implement their own load reduction via telephone, by either an automated calling system or a manual call to a business telephone number or cellular phone number designated by the customer. The designated telephone number will be used for the sole purpose of receiving SCE’s rotating outage notification and must be available to receive the notification at all times. When SCE sends the notification to the designated telephone number the customer is responsible for dropping its entire load in accordance with subsection a. (i), above. The customer is responsible for informing SCE, in writing, of the telephone number and contact name for purposes of receiving the notification of a rotating outage.

(Continued)

Schedule I-6 Sheet 13
TIME-OF-USE
GENERAL SERVICE - LARGE - INTERRUPTIBLE
(Continued)

SPECIAL CONDITIONS (Continued)

20. Customers with Service Metered and Delivered at Voltages above 50 kV (Sub-transmission customers) Included in Rotating Outages. (Continued) (T)

a. Customer-Implemented Load Reduction. (Continued)

(iii) Excess Energy Charges. If a Sub-transmission customer fails to drop its entire load within 30 minutes of notification by SCE, and/or fails to maintain the entire load drop until 90 minutes after the time notification was sent to the customer, unless SCE otherwise notified the customer that it may return its load to service earlier in accordance with subsection a. (i) above, SCE shall assess Excess Energy Charges of $6 per kWh for all kWh usage in excess of the Authorized Residual Ancillary Load. Such charges will be based on the total kWh usage during the applicable rotating outage penalty period, less the product of Authorized Residual Ancillary Load in kW and the applicable rotating outage penalty period in hours. Excess Energy Charges will be determined and applied by SCE subsequent to the Sub-transmission customer's regularly scheduled meter read date following the applicable rotating outage.

(iv) Authorized Residual Ancillary Load. Authorized Residual Ancillary Load is load that is deemed to be equivalent to five percent of the Sub-transmission customer's prior billing month's recorded Maximum Demand. This minimum load level is used as a proxy to allow for no-load transformer losses and/or load attributed to minimum grid parallel operation for generators connected under Rule 21.

b. SCE-Implemented Load Reduction.

Non-exempt Sub-transmission customers may request, in writing, to have SCE drop the customer's entire load during all applicable rotating outages using SCE's remote-controlled load drop equipment (control equipment). If SCE agrees to such arrangement, SCE will implement the load drop by using one of the following methods:

(i) Control Equipment Installed. For a Sub-transmission customer whose load can be dropped by SCE's existing control equipment, SCE will implement the load drop during a rotating outage applicable to the customer. The customer will not be subject to the Notification and Excess Energy Charge provisions set forth in subsection a, above.

(Continued)

Schedule I-6 Sheet 14
TIME-OF-USE
GENERAL SERVICE - LARGE - INTERRUPTIBLE
(Continued)

SPECIAL CONDITIONS (Continued)

20. Customers with Service Metered and Delivered at Voltages above 50 kV (Sub-transmission customers) Included in Rotating Outages. (Continued) (T)

b. SCE-Implemented Load Reduction. (Continued)

(ii) Control Equipment Pending Installation. For a Sub-transmission customer whose load can not be dropped by SCE's existing control equipment, the customer must request the installation of such equipment at the customer's expense in accordance with SCE's Rule 2, Section H, Added Facilities. Pending the installation of the control equipment, the customer will be responsible for dropping load in accordance with the provisions of subsection a, above, including the Notification and Excess Energy Charge provisions.

c. Non-compliance: A non-exempt Sub-transmission customer subject to subsection a, above, who fails to drop load during three rotating outages in a three year period to a demand level of 20% or less of the customer's prior billing month's recorded Maximum Demand averaged over the applicable rotating outage period, is not in compliance with this tariff. The three year period shall commence with the first failure to drop load as specified in this subsection. A customer not in compliance with this condition will be placed at the top of the Sub-transmission customer rotating outage group list and will be expected to comply with subsequent applicable rotating outages. In addition, the customer must select one of the two options below within fifteen days after receiving written notice of non-compliance from SCE. A customer failing to make a selection within the specified time frame will be subject to subsection c. (ii) below.

(i) Subject to Schedule OBMC: The customer shall submit an OBMC Plan, in accordance with Schedule OBMC, within 30 calendar days of receiving written notice of non-compliance from SCE. Pending the submittal of the OBMC Plan by the customer and pending the review and acceptance of the OBMC Plan by SCE, the customer will remain responsible for dropping load in accordance with the provisions of subsection a, above, including the Notification and Excess Energy charge provisions. If the customer fails to submit an OBMC Plan within 30 days of receiving notice of non-compliance from SCE, or if the customer's OBMC Plan is not approved by SCE, or if the customer fails to meet the requirements of Schedule OBMC once the OBMC Plan is approved, the customer shall be subject subsection c. (ii), below.

(ii) Installation of Control Equipment. The customer shall be subject to the installation of control equipment at the customer's expense in accordance with SCE's Rule 2, Section H, Added Facilities, if such equipment is not currently installed. If such switching capability is installed, SCE will drop the customer's load for all applicable subsequent rotating outages in accordance with the provisions of subsection b, above. Pending the installation of control equipment, the customer will remain responsible for dropping load in accordance with the provisions of subsection a, above, including the Notification and Excess Energy Charge provisions.

(Continued)

SPECIAL CONDITIONS (Continued)

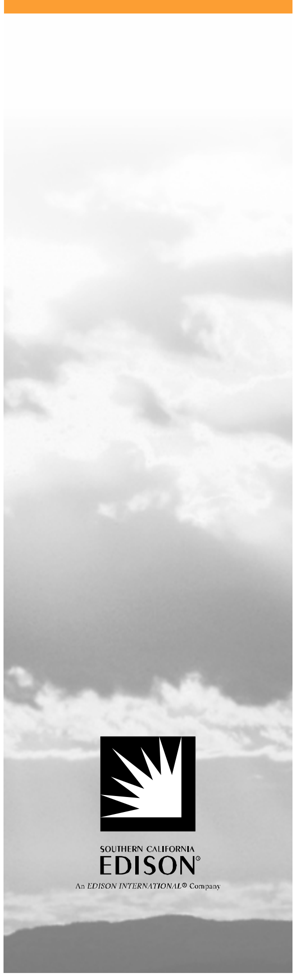
20. Customers with Service Metered and Delivered at Voltages above 50 kV (Sub-transmission customers) Included in Rotating Outages. (Continued) (T)

d. Net-Generators

Sub-transmission customers who are also net-generators are normally exempt from rotating outages, but they must be net suppliers of power to the grid during all rotating outages. For the purpose of this Special Condition, a net-generator is an SCE customer who operates an electric generating facility as part of its industrial or commercial process, and the generating facility normally produces more electrical power than is consumed in the industrial or commercial process, with the excess power supplied to the grid. Sub-transmission customers whose primary business purpose is to generate power are not included in this Special Condition.

(i) Notification of Rotating Outages. SCE will notify sub-transmission customers who are net-generators of all rotating outages applicable to customers within SCE's service territory. Within 30 minutes of notification, the customer must ensure it is a net supplier of power to the grid throughout the entire rotating outage period. Failure to do so will result in the customer losing its exemption from rotating outages, and the customer will be subject to Excess Energy Charges, as provided below.

(ii) Excess Energy Charges. Net generators who are not net suppliers to the grid during each rotating outage period will be subject to Excess Energy Charges of $6 per kWh for all kWh usage in excess of the Authorized Residual Ancillary Load. Such charges will be based on the total kWh usage during a rotating outage penalty period, less the product of Authorized Residual Ancillary Load in kW and the applicable rotating outage period hours. Excess Energy Charges will be determined and applied by SCE subsequent to the customer's regularly scheduled meter read date following the applicable rotating outage. Excess Energy Charges shall not apply during periods of verifiable scheduled generator maintenance or if the customer's generator suffers a verifiable forced outage. The scheduled maintenance must be approved in advance by either the ISO or SCE, but approval may not be unreasonably withheld.



INFORMATION ABOUT SCE'S I-6 AND RTP-2-I PRICING OPTIONS

For Business Operations Above 500 kW

The I-6 and RTP-2-I pricing options provide lower energy and/or time-related demand charges for that portion of power usage a customer is willing to interrupt when requested to do so by SCE. Schedules I-6 and RTP-2-I were closed on November 26, 1996, but remain available to eligible customers above 500 kW who are adding new load or who are new to SCE's service territory.

Who is eligible?

1. An existing customer who is expanding its operations and adds new load can have such new load served on a large power interruptible pricing option.*

2. A current customer who opens a new service account with new load would be allowed to put the new load on an interruptible pricing option as long as the load was not previously served by SCE.

3. Customers new to SCE's service territory are allowed to put their load on an interruptible pricing option.

4. I-6 customers may participate in TOU-BIP without losing their I-6 discounts, but they will only receive TOU-BIP credits after their annual I-6 obligations have been fulfilled.

5. I-6 customers may participate in the Demand Bidding Program (DBP), the California Demand Reserves Partnership (Cal-DRP), and the Optional Binding Mandatory Curtailment Program (OBMC), but cannot be paid for the same reduced load.

6. I-6 customers may not participate in the Critical Peak Pricing (CPP) Programs or the California Independent System Operator's (CAISO) Ancillary Services Load Program.

Customers currently served on an interruptible rate continue to be subject to the terms and conditions of their interruptible contract.

** For customers already taking service on the I-6 or RTP-2-I pricing option and who expand their operations and add new load, the additional load will be treated as interruptible load unless they contact SCE before adding this additional load.*

RATE DISCOUNT

The overall rate reduction for those participating in SCE's I-6 or RTP-2-I pricing options depends on the demand the customer places on SCE's system, the time of day and season when the customer uses energy, and the amount of electricity the customer designates as "interruptible." The portion of the customer's electrical usage designated as "firm service" (non-interruptible) usage is billed on a time-of use, real-time pricing, or time-of-use super-off peak rate such as TOU-8, RTP-2, or TOU-8-SOP. The applicable interruptible rate applies only to the portion of a customer's power usage designated as "interruptible," which is usage that is in excess of a customer's designated Firm Service Level (FSL).

ESSENTIAL USE CUSTOMERS

Essential Use customers (those whose operations are designated as essential to the health and safety of the citizens of California) are exempt from rotating outages. Essential Use customers may remain on the I-6 or RTP-2-I pricing options, but must complete and submit an "Essential Use" Declaration. The Declaration states that the customer is, to the best of their understanding, an Essential Use customer under California Public Utilities Commission (CPUC) rules and exempt from rotating outages. The Declaration also states that the customer voluntarily elects to participate in an interruptible program for no more than 50% of their load based on adequate backup generation or other means to interrupt power upon request by SCE while continuing to meet its essential needs.

COSTS TO SIGN-UP FOR SCE'S I-6 OR RTP-2-I PRICING OPTIONS

Although SCE provides the Remote Terminal Unit (RTU) to customers at no charge, there is a fee to cover the cost of its installation, set-up, and ongoing maintenance. In addition, customers are required to provide and maintain two dedicated, unlisted telephone lines for the sole purpose of receiving SCE notices of interruption. One telephone line is for the RTU and the other line is for an I-6 program dedicated telephone.

CUSTOMER OBLIGATIONS

Customers taking service on I-6 or RTP-2-I, agree to several conditions, including those listed below:

FIRM SERVICE LEVEL (FSL)

The Firm Service Level (FSL) is the amount of electricity customers determine is necessary for them to meet their operational requirements during an interruption event. Interruptible customers are requested to reduce electrical load to their designated FSL, or "non-interruptible" level, within 30 minutes of receiving an interruption notice from SCE. In exchange for agreeing to reduce electrical usage to their designated FSL, SCE provides participating customers with lower rates for all usage above their FSL, whether or not an interruption event occurs. Essential Use customers cannot set their FSL at less than 50% of their maximum demand.

REMOTE TERMINAL UNIT (RTU) INSTALLATION AND ACCESS

In general, SCE notifies customers of an interruption event by means of a Remote Terminal Unit (RTU) device and dedicated telephone installed at the customer's site. Customers are responsible for providing a communication cable in conduit from the RTU to an SCE interface enclosure. Because the RTU is SCE-owned equipment, it must be installed in a location suitable and accessible to SCE during reasonable hours for maintenance and repair.

ISOLATED POWER SUPPLY

The RTU must be powered at all times and must be connected to a power source (115-volt AC, supplied through conduit from a dedicated 15-amp or 20-amp circuit breaker) isolated from the electric load that is subject to an interruption event.

TELEPHONE LINES

In general, interruptible customers must install two telephone lines—one line that is connected to the RTU and another line that is connected to a dedicated telephone for the purpose of notification. The dedicated telephone lines should:

- <u>Not</u> have dial out capability. Its only purpose is to receive calls from SCE. NO other calls should be made on these lines. Cellular phones are not acceptable.
- Be an unlisted telephone number. Only SCE calls should be received on these lines.
- Be a direct line. Calls cannot go through a switchboard, voicemail system, or answering machine.
- Be located in an area where it can be immediately answered at all times.

NOTIFICATION OF AN INTERRUPTION

The RTU is the primary means of a notice of interruption. However, SCE will also place a call to the customer's dedicated telephone when there is an interruption event. The latter of the notices sent to the RTU or dedicated telephone will serve as the customer's official notice of an interruption event. In most cases, the notices are sent within several minutes of each other.

Interruptible customers may not substitute the use of the interruptible Web site, paging service, e-mail notification service, or SCE's toll-free telephone numbers as an alternative method of receiving SCE's notice to interrupt. These services are provided as a courtesy only and are not alternatives to the RTU and dedicated telephone. Failure to answer a call from SCE to interrupt power that results in the customer's failure to interrupt load will result in penalties for failing to comply with a notice of interruption, as described in the program tariffs.

INTERRUPTION FREQUENCY AND DURATION

An interruption event may occur when there is a Stage 2 Emergency (operating reserves are forecast to drop below 5%), transmission line constraints, or other constraints. The CAISO will direct SCE to reduce a specific amount of electrical load. SCE will then notify its interruptible customers to reduce electrical usage to their FSL within 30 minutes of receiving the notification to avoid penalties.

Interruption events are limited to 1 event per day, 4 events per week (defined as Sunday through Saturday), and 25 events per year. An event will not exceed 6 hours, and the total periods of interruption will not be more than 40 hours per month or 150 hours per calendar year.

The CAISO can call for an interruption event AT ANY TIME — 24 hours a day, 7 days a week, 365 days a year.

PENALTIES

Penalties, or "Excess Energy Charges," apply to customers who fail to reduce load to their designated FSL during an interruption event. Interruptible customers have 30 minutes from the time they initially receive the signal, indicating the beginning of an interruption event, to fully comply with the request to interrupt. Penalties are assessed for each interruption event when a customer fails to reduce its electrical usage to its FSL. The applicable penalties range from $10.06 to $10.65 per kWh of excess energy consumed during the interruption event, depending upon the customer's service voltage level.

Are there any contractual requirements?

Yes. An "Agreement" is required which is available through your representative. In this agreement, you must designate which service accounts you would like to participate in the program.

Can a customer cancel an I-6 Interruptible Program contract or adjust the firm service level?

Yes. You can increase or decrease your FSL or terminate your I-6 Interruptible Program Contract during the annual opt-out window from November 1 to December 1.

MONTHLY TEST

To verify that the RTU's automatic notification and dedicated telephone are working properly, SCE conducts a Communications Test on the first Tuesday of each month, between the hours of 8 a.m. and 12 p.m. This monthly test is similar to an actual interruption event except the customer is NOT required to reduce electrical load and customers are NOT subject to penalties. (Customers who have installed automatic load-shed systems on the RTU may want to install a timer device or other mechanism to avoid automatic reduction of electrical load during a test.) The customer may use the monthly test to check external alarm systems and practice their internal procedures and communications for handling actual interruption events.

ACKNOWLEDGING THE RTU TEST SIGNAL: To acknowledge an interruption event signal on a RTU, press the "Acknowledge" button. Customers are not required to acknowledge the RTU signal during a monthly test; however, it is good practice for the customer's operations personnel to do so. Remember, failing to depress the "Acknowledge" button during an actual interruption event does not relieve a customer's obligation to reduce electrical usage to its firm service level. Customers will also receive a test call on their dedicated telephone. They should answer the test call and review their internal procedures for handling of an interruption event.

WHAT TO DO DURING AN INTERRUPTION EVENT

SCE notifies customers of an interruption event by sending a signal to the RTU and an automated or manual message to their dedicated telephone. When SCE sends the signal to the RTU and/or the automated or manual message is sent to the dedicated telephone, the customer is being notified to reduce electrical usage to their FSL. Interruption events may occur AT ANY TIME, therefore, it is recommended that someone be available to respond to an interruption event at all times.

CUSTOMERS WITH A REMOTE TERMINAL UNIT: When the RTU receives the interruption event signal its alarm will sound. The alarm can be silenced at that time by pressing the "Acknowledge" button. Shortly before or after the alarm sounds, customers will receive a call on their dedicated phone notifying them of the interruption. Customers have 30 minutes from the time the signal is sent by SCE to fully comply with the request to interrupt or the

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customer is subject to penalties. Failure to acknowledge the signal does not excuse a customer from their obligation to reduce their electrical load to their FSL. If they do not comply with the notice to interrupt, applicable Excess Energy Charges will be assessed. When the interruption event concludes, SCE sends another signal to the RTU, again sounding its alarm. The customer will also receive another call on the dedicated phone at the end of the interruption. As before, pressing the "Acknowledge" button will silence the RTU's alarm. If the "Acknowledge" button is not pressed at the conclusion of an interruption event, the alarm will silence after 10 minutes.

How can a customer get additional Interruptible Program Status Information?

SCE manages and operates additional Interruptible Status resources as a courtesy, providing a broader perspective of events surrounding an interruption event. (In rare cases, we may experience rapid interruptible information changes, which can delay the updating of these systems. In these situations, every effort is made to provide the most up-to-date information.)

- **Interruptible Program Status Telephone Line (888) 334-7764** toll-free, 24 hours a day, 7 days a week
- **Internet Interruptible Program Web site, www.sce.com/I-6**
- **E-mail Notification Service**
- **Paging Service**

NOTE: Use of any of the above additional services ARE NOT substitutes for monitoring of the RTU's or dedicated telephones, for purposes of responding to the notification to interrupt. SCE will use the RTU and dedicated telephone to notify the customer that an interruption event is underway.

PROCURING POWER FROM ANOTHER PROVIDER

The right of retail customers to elect to procure power from providers other than SCE was suspended by the COUC on September 20, 2001. Customers currently receiving services from another provider [third-party provider or Energy Service Provider (ESP)] will continue to be billed for the non-generation charges through the applicable SCE tariff, while their generation cost component will be billed according to the terms and charges agreed upon with their ESP.

FOR MORE INFORMATION

SCE has several programs available to help customers better manage their electricity costs, such as rebates, incentives, energy surveys and payment options. If you have other questions about the I-6 or RTP-2-I pricing options or other SCE programs, call **(800) 990-7788**, or visit www.sce.com, or www.sce.com/I-6. To learn more about other Demand Response Programs, go to www.sce.com/DRP.

SCHEDULE AL-TOU-CP

GENERAL SERVICE - CRITICAL PEAK

APPLICABILITY

This schedule is applicable to non-residential customers requesting service on this schedule except that this schedule is closed to additional customers with the exception of customers installing Distributed Generators. Schedule AV-1 customers who transfer to this schedule pursuant to D.02-09-034 and subsequently discontinue service under this schedule cannot return to this rate schedule.

TERRITORY

Within the entire territory served by the Utility.

RATES

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Description	Transm	Distr	PPP	ND	FTA	TTA Credit	CTC	RS	UDC Total
Signaling Equipment Charge ($/new cust)		5,130.10							**5,130.10**
Contact Closure		86.63							**86.63**
Basic Service Fees ($/month)									
0-500 kW									
Secondary		48.52							**48.52**
Primary		48.52							**48.52**
Secondary Substa.		13858.43							**13858.43**
Primary Substation		13858.43							**13858.43**
Transmission		61.36 I							**61.36** I
> 500 kW									
Secondary		194.06							**194.06**
Primary		194.06							**194.06**
Secondary Substa.		13858.43							**13858.43**
Primary Substation		13858.43							**13858.43**
Transmission		245.49 I							**245.49** I
> 12 MW									
Secondary Substa.		21820.90							**21820.90**
Primary Substation		21820.90							**21820.90**
Distance Adjust. Fee									
Secondary - OH		1.23							**1.23**
Secondary - UG		3.17							**3.17**
Primary - OH		1.22							**1.22**
Primary - UG		3.13							**3.13**

(Continued)

SCHEDULE AL-TOU-CP

GENERAL SERVICE - CRITICAL PEAK

RATES (Continued)

Description	Transm	Distr	PPP	ND	FTA	CTC	RS	UDC
Demand Charges ($/kW)								
Non-Coincident								
Secondary	2.79	6.56 I				0.34	2.33	**12.02** I
Primary	2.69	6.46 I				0.31	2.25	**11.71** I
Secondary Substation	2.79					0.34	2.33	**5.46**
Primary Substation	2.69					0.03	2.25	**4.97**
Transmission	2.66					0.03	2.23	**4.92**
Maximum On-Peak								
Summer								
Secondary		4.29 I				1.50		**5.79** I
Primary		4.15 I				1.46		**5.61** I
Secondary Substation						1.50		**1.50**
Primary Substation						1.07		**1.07**
Transmission						1.06		**1.06**
Winter								
Secondary		3.65 I				0.35		**4.00** I
Primary		3.64 I				0.34		**3.98** I
Secondary Substation						0.35		**0.35**
Primary Substation						0.22		**0.22**
Transmission						0.22		**0.22**
Power Factor ($/kvar)								
Secondary		0.25						**0.25**
Primary		0.25						**0.25**
Secondary Substation		0.25						**0.25**
Primary Substation		0.25						**0.25**
Transmission								

(Continued)

SCHEDULE AL-TOU-CP

Sheet 3

GENERAL SERVICE - CRITICAL PEAK

RATES (Continued)

Description	Transm	Distr	PPP	ND		FTA	CTC	RS	UDC Total	
Energy Charges ($/kWh)										
On-Peak - Summer										
Secondary	(0.00155)		0.00576	0.00046	R		0.00578	0.00378	**0.01423**	R
Primary	(0.00155)		0.00576	0.00046	R		0.00563	0.00378	**0.01408**	R
Secondary Substation	(0.00155)		0.00576	0.00046	R		0.00578	0.00378	**0.01423**	R
Primary Substation	(0.00155)		0.00576	0.00046	R		0.00544	0.00378	**0.01389**	R
Transmission	(0.00155)		0.00576	0.00046	R		0.00540	0.00378	**0.01385**	R
Semi-Peak - Summer										
Secondary	(0.00155)		0.00576	0.00046	R		0.00337	0.00378	**0.01182**	R
Primary	(0.00155)		0.00576	0.00046	R		0.00330	0.00378	**0.01175**	R
Secondary Substation	(0.00155)		0.00576	0.00046	R		0.00337	0.00378	**0.01182**	R
Primary Substation	(0.00155)		0.00576	0.00046	R		0.00321	0.00378	**0.01166**	R
Transmission	(0.00155)		0.00576	0.00046	R		0.00318	0.00378	**0.01163**	R
Off-Peak - Summer										
Secondary	(0.00155)		0.00576	0.00046	R		0.00265	0.00378	**0.01110**	R
Primary	(0.00155)		0.00576	0.00046	R		0.00261	0.00378	**0.01106**	R
Secondary Substation	(0.00155)		0.00576	0.00046	R		0.00265	0.00378	**0.01110**	R
Primary Substation	(0.00155)		0.00576	0.00046	R		0.00257	0.00378	**0.01102**	R
Transmission	(0.00155)		0.00576	0.00046	R		0.00255	0.00378	**0.01100**	R
On-Peak - Winter										
Secondary	(0.00155)		0.00576	0.00046	R		0.00483	0.00378	**0.01328**	R
Primary	(0.00155)		0.00576	0.00046	R		0.00471	0.00378	**0.01316**	R
Secondary Substation	(0.00155)		0.00576	0.00046	R		0.00483	0.00378	**0.01328**	R
Primary Substation	(0.00155)		0.00576	0.00046	R		0.00455	0.00378	**0.01300**	R
Transmission	(0.00155)		0.00576	0.00046	R		0.00453	0.00378	**0.01298**	R
Semi-Peak - Winter										
Secondary	(0.00155)		0.00576	0.00046	R		0.00339	0.00378	**0.01184**	R
Primary	(0.00155)		0.00576	0.00046	R		0.00331	0.00378	**0.01176**	R
Secondary Substation	(0.00155)		0.00576	0.00046	R		0.00339	0.00378	**0.01184**	R
Primary Substation	(0.00155)		0.00576	0.00046	R		0.00322	0.00378	**0.01167**	R
Transmission	(0.00155)		0.00576	0.00046	R		0.00320	0.00378	**0.01165**	R
Off-Peak - Winter										
Secondary	(0.00155)		0.00576	0.00046	R		0.00268	0.00378	**0.01113**	R
Primary	(0.00155)		0.00576	0.00046	R		0.00264	0.00378	**0.01109**	R
Secondary Substation	(0.00155)		0.00576	0.00046	R		0.00268	0.00378	**0.01113**	R
Primary Substation	(0.00155)		0.00576	0.00046	R		0.00259	0.00378	**0.01104**	R
Transmission	(0.00155)		0.00576	0.00046	R		0.00257	0.00378	**0.01102**	R

Notes: Transmission Energy charges include the Transmission Revenue Balancing Account Adjustment (TRBAA) of ($.00164) per kWh and the Transmission Access Charge Balancing Account Adjustment (TACBAA) of $.00009 per kWh. PPP rate is composed of: Low Income PPP rate (LI-PPP) $.00162/kWh, Non-low Income PPP rate (Non-LI-PPP) $.00256/kWh (pursuant to PU Code Section 399.8, the Non-LI-PPP rate may not exceed January 1, 2000 levels), and Procurement Energy Efficiency Surcharge Rate of $.00158/kWh.

(Continued)

SCHEDULE AL-TOU-CP

GENERAL SERVICE - CRITICAL PEAK

Rate Components

The Utility Distribution Company Total Rates (UDC Total) shown above are comprised of the following components (if applicable): (1) Transmission (Trans) Charges, (2) Distribution (Distr) Charges, (3) Public Purpose Program (PPP) Charges, (4) Nuclear Decommissioning (ND) Charge, (5) Trust Transfer Amount (TTA), sometimes referred to as Fixed Transition Amount (FTA), (6) Ongoing Competition Transition Charges (CTC), and (7) Reliability Services (RS). T T

Utility Distribution Company (UDC) Total Rate shown above excludes any applicable commodity charges associated with Schedule EECC (Electric Energy Commodity Cost) and Schedule DWR-BC (Department of Water Resources Bond Charge).

Fixed Transition Amount Adjustment

For residential and small commercial customers as defined in Rule 1 – Definitions, and as described in Public Utilities Code Section 331(h), the rates shown above will be adjusted in accordance with the rates set forth in Schedule FTA.

Time Periods

All time periods listed are applicable to local time. The definition of time will be based upon the date service is rendered.

	Summer May 1 - Sept 30	Winter All Other
On-Peak	11 a.m. - 6 p.m. Weekdays	5 p.m. - 8 p.m. Weekdays
Semi-Peak	6 a.m. - 11 a.m. Weekdays 6 p.m. - 10 p.m. Weekdays	6 a.m. - 5 p.m. Weekdays 8 p.m. - 10 p.m. Weekdays
Off-Peak	10 p.m. - 6 a.m. Weekdays Plus Weekends & Holidays	10 p.m. - 6 a.m. Weekdays Plus Weekends & Holidays

Non-Standard Seasonal Changeover

Customers may select on an optional basis to start the summer billing period on the first Monday of May and to start the winter billing period on the first Monday of October. Customers electing this option will be charged an additional $100 per year for metering equipment and programming.

Franchise Fee Differential

A Franchise Fee Differential of 5.78% will be applied to the monthly billings calculated under this schedule for all customers within the corporate limits of the City of San Diego. Such Franchise Fee Differential shall be so indicated and added as a separate item to bills rendered to such customers.

Large Customer CTC Adjustment

Large Customers, as defined in Rule 1 - Definitions, shall have a Transition Cost Balancing Account (TCBA) bill credit calculated each month that is equal to the CTC rates above, multiplied by the billing determinates as delivered by the Utility to the customer, multiplied by 1.38. This CTC adjustment is effective for a 12-month period, beginning January 1, 2005. Customers that would be billed a CTC for the output of their generator(s) will, for all billing periods commencing after the effective date of this provision, not be billed a CTC for that output. The Utility shall record this amount against the balance in the TCBA.

(Continued)

SCHEDULE AL-TOU-CP

GENERAL SERVICE - CRITICAL PEAK

RATES (Continued)

Large Customer Commodity Credit
Large Customers, as defined in Rule 1 – Definitions, who are receiving bundled service will receive a commodity credit for a 24-month period beginning January 1, 2004. Large Customers will receive a monthly credit in the amount of $0.01313/kWh. This credit represents the return of an overcollection in the large customer subaccount of the Energy Resource Recovery Account (ERRA).

SPECIAL CONDITIONS

1. Definitions: The Definitions of terms used in this schedule are found either herein or in Rule 1.

2. Period 1G Rates: During the time period in which a Period 1G Signal is in effect the Signaled Period 1G rate shown on Schedule EECC and all applicable "On-Peak" UDC rates shall apply. T T

3. Voltage: Service under this schedule normally will be supplied at a standard available Voltage in accordance with Rule 2.

4. Voltage Regulators: Voltage Regulators, if required by the customer, shall be furnished, installed, owned, and maintained by the customer.

5. Reconnection Charge: In the event that a customer terminates service under this schedule and re-initiates service under this or any other schedule at the same location within 12 months, there will be a Reconnection Charge equal to the greater of the Minimum Charge or the Basic Service Fee which would have been billed had the customer not terminated service.

6. Non-Coincident Demand Charge: The Non-Coincident Demand Charge shall be based on the higher of the Maximum Monthly Demand or 50% of the Maximum Annual Demand.

7. Power Factor: The Power Factor rate shall apply to those customers that have a Power Factor Test Failure and will be based on the Maximum Kilovar Billing Demand. Those customers that have a Power Factor Test Failure will be required to pay for the Power Factor Metering that the utility will install.

8. Basic Service Fee Determination. Customers subject to the Signaling Equipment Charge are subject to a reduced Contact Closure Fee of $20.00 per month. The basic service fee will be determined each month based on the customer's Maximum Annual Demand.

9. Interconnection Facilities. Any customer with electric generation facilities shall furnish and maintain control and protective apparatus which the utility may require for the operation of the customer facilities in parallel with the utility's system. The customer will provide a disconnecting device located near the electric meter(s). The utility shall have the right to disconnect the customer's facilities when, in its sole opinion it is necessary to maintain safe electrical operating conditions. Interconnection Facilities shall be accessible at all times to utility personnel. Customer shall provide for the installation of a meter(s) that registers the net output of any electric generator on customer's property.

   Prior to the initial energizing and start-up testing of the customer-owned generator, the customer shall notify the utility and the utility may have a representative present at such test. Additionally, the customer shall comply with all utility rules.

(Continued)

SCHEDULE AL-TOU-CP

GENERAL SERVICE - CRITICAL PEAK

SPECIAL CONDITIONS (Continued)

10. Peak Shaving. There is no Utility limitation for customers to operate parallel generation that are qualified for this rate schedule and have an Interconnection Agreement with the Utility. A customer operating any generation under this schedule must adhere to the terms and conditions under Rule 21 other than the requirements of being a Qualifying Facility. T T

11. Net Energy. Net Energy is energy supplied by the utility minus energy generated by the customer and fed back into the utility's system at any instant in time. Unless covered by a contract, Net Energy shall not be negative.

12. Limitations of Availability. This schedule shall be available to no more than 5 new customers per calendar month.

13. Tariff Switching Limitation. Customers who elect to discontinue service provided by Schedule AL-TOU-CP will be prohibited from receiving service on Schedule AL-TOU-CP for a 12-month period unless the new service immediately follows service on AL-TOU-CP.

14. Termination of Schedule. This schedule is subject to review and termination in the Utility's next General Rate Case. If the Commission decides to terminate the schedule, a 36-month notice will be given to customers served on this schedule prior to the schedule's termination, unless otherwise decided by the Commission.

15. Billing. A customer’s bill is first calculated according to the total rates and conditions listed above. The following adjustments are made depending on the option applicable to the customer:

    a. **UDC Bundled Service Customers** receive supply and delivery services solely from SDG&E. The customer’s bill is based on the Total Rates set forth above. The EECC component is determined by multiplying the EECC price for this schedule during the last month by the customer’s total usage.
    b. **Direct Access Customers** purchase energy from an energy service provider (ESP) and continue to receive delivery services from SDG&E. The bill for a Direct Access Customer will be calculated as if it were a UDC Bundled Service Customer, then crediting the bill by the amount of the EECC component, as determined for a UDC Bundled Customer.
    c. **Virtual Direct Access Customers** receive supply and delivery services solely from SDG&E. A customer taking Virtual Direct Access service must have a real-time meter installed at its premises to record hourly usage, since EECC change hourly. The bill for a Virtual Direct Access Customer will be calculated as if it were a UDC Bundled Service Customer, then crediting the bill by the amount of the EECC component, as determined for a UDC Bundled Customer, then adding the hourly EECC component, which is determined by multiplying the hourly energy used in the billing period by the hourly cost of energy.

    Nothing in this service schedule prohibits a marketer or broker from negotiating with customers the method by which their customer will pay the CTC charge.

(Continued)

SCHEDULE AL-TOU-CP

GENERAL SERVICE - CRITICAL PEAK

SPECIAL CONDITIONS (Continued)

16. Insurance: Insurance may not be used to pay Signaled Period 1G rates for willful failure to comply. Each customer must provide the utility with an executed declaration that states "I do not have, and will not obtain, insurance to compensate me in any way for any portion of the bills associated with the Signaled Period 1G rates." Such declaration (Form 142-05209) must be on file with the utility within 30 days of the effective date of the tariffs or the customer will immediately begin service on Schedule AL-TOU in lieu of continued service on Schedule AL-TOU-CP. T

17. Electric Emergency Load Curtailment Plan: As set forth in CPUC Decision 01-04-006, all transmission level customers except essential use customers, OBMC participants, net suppliers to the electrical grid, or others exempt by the Commission, are to be included in rotating outages in the event of an emergency. A transmission level customer who refuses or fails to drop load shall be added to the next curtailment block so that the customer does not escape curtailment. If the transmission level customer fails to cooperate and drop load at SDG&E's request, automatic equipment controlled by SDG&E will be installed at the customer's expense per Electric Rule 2. A transmission level customer who refuses to drop load before installation of the equipment shall be subject to a penalty of $6/kWh for all load requested to be curtailed that is not curtailed. The $6/kWh penalty shall not apply if the customer's generation suffers a verified, forced outage and during times of scheduled maintenance. The scheduled maintenance must be approved by both the ISO and SDG&E, but approval may not be unreasonably withheld. T

D

18. Other Applicable Tariffs: Rules 21, 23 and Schedule E-Depart apply to customers with generators. T

SCHEDULE EECC

ELECTRIC ENERGY COMMODITY COST

APPLICABILITY

Applicable to all customers who receive UDC bundled service.

TERRITORY

Applicable throughout the territory served by the Utility.

RATES

This schedule has two purposes: (1) billing UDC Bundled Service customers for commodity energy, which consists of Utility supplied electricity sold by SDG&E to its customers and DWR supplied electricity sold by DWR to SDG&E customers with SDG&E acting as billing agent; and (2) developing Department of Water Resources (DWR) and Utility Supplied Energy Percentage. The rate tables show EECC fixed billing rates for all retail rate schedules. The combined Utility/DWR fixed billed commodity rates were designed to collect the imputed utility rate of $0.065/kWh on all Utility electricity supplied to the customer and the DWR interim charge of $0.0902/kWh (defined in D.01-09-059) on all DWR electricity sold to the customer including an adjustment for the $0.00485/kWh adopted by Decision 05-12-010. I, T

Commodity Rates

Schedules DR, DM, DS, DT, DT-RV

	($/kWh)	
Summer		
Baseline	0.06855	I
101% - 130% of Baseline	0.06855	I
131% - 200% of Baseline	0.06855	I
201% - 300% of Baseline	0.06855	I
Above 300% of Baseline	0.06855	R
Winter		
Baseline	0.04678	I
101% - 130% of Baseline	0.04678	R
131% - 200% of Baseline	0.04678	R
201% - 300% of Baseline	0.04678	R
Above 300% of Baseline	0.04678	R

Schedules DR-TOU and DR-TOU-DER

	On-Peak ($/kWh)	Off-Peak ($/kWh)
Summer		
Baseline	0.11515 I	0.05460 I
101% - 130% of Baseline	0.11515 I	0.05460 I
131% - 200% of Baseline	0.11515 I	0.05460 R
201% - 300% of Baseline	0.11515 I	0.05460 R
Above 300% of Baseline	0.11515 I	0.05460 R
Winter		
Baseline	0.05619 I	0.04997 I
101% - 130% of Baseline	0.05619 I	0.04997 I
131% - 200% of Baseline	0.05619 I	0.04997 R
201% - 300% of Baseline	0.05619 R	0.04997 R
Above 300% of Baseline	0.05619 R	0.04997 R

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(Continued)

SCHEDULE EECC

ELECTRIC ENERGY COMMODITY COST

RATES (Continued)

Commodity Rates (Continued)

Schedules DR-LI and medical baseline customers		
Summer		
Baseline	0.06855	I
Up to 130% of Baseline	0.06855	I
Above 130% of Baseline	0.06855	I
Winter		
Baseline	0.04678	R
Up to 130% of Baseline	0.04678	R
Above 130% of Baseline	0.04678	R
Schedule E-LI (Non-residential rate schedule)		
All Usage	0.05691	I
Schedules EV-TOU, EV-TOU-2, and EV-TOU-3		
On-Peak	0.09788	I
Off-peak	0.04769	R
Super Off-peak	0.02960	R
Schedule A		
Summer		
Secondary	0.08144	I
Primary	0.08144	I
Winter		
Secondary	0.05617	R
Primary	0.05617	R
Schedule A-TC		N
All Usage	0.06672	R
Schedules A-TOU, AL-TOU, AL-TOU-DER, AY-TOU, A6-TOU and PA-T-1		
On-Peak	0.11515	I
Semi-Peak	0.06637	I
Off-Peak	0.04537	R
Schedule AL-TOU-CP		
Signal Period IG	1.79153	
On-Peak	0.11025	I
Semi-Peak	0.06148	I
Off-Peak	0.04048	R
Schedule AD		N
All Usage	0.06675	R
Schedule PA		N
All Usage	0.06360	R
Schedules LS-1, LS-2, LS-3, OL-1 and DWL		N
All Usage	0.04764	R

(Continued)

SCHEDULE EECC

ELECTRIC ENERGY COMMODITY COST

RATES (Continued)

DWR Power Charge
Pursuant to CPUC Decision 05-12-010, DWR's Power Charge is 8.142 cents per kWh. I,T

Franchise Fees
A Franchise Fee Differential of 5.78% will be applied to the total bills calculated under this schedule, including DWR charges, for all customers residing within the corporate limits of the City of San Diego. Such Franchise Fee Differential shall be so indicated and added as a separate item to bills rendered to such customers.

Franchise Fees associated with DWR electricity sales will be reflected in a separate line item on customer bills titled "Franchise Fees for Electric Energy Supplied by Others".

Distribution Loss Factors (DLFs)

The DLF_{TLL} for each voltage level includes a factor for lost and unaccounted for energy. DLF_{TLL} will be calculated by the utility based on the forecast hourly SDG&E UDC Service Area Load (Direct Access, plus UDC customers, including the Hourly EECC Rate Option Service) per Decision 97-08-056, as modified by Decision 97-11-026. The hourly DLF_{TLL} will be broken out by service voltage level and made available each day to market participants during the day-ahead market. The utility will calculate the hourly DLF_{TLL} by applying the following formulae:

a. **Secondary Voltage Class Customers**

DLF_{DLL} = 1 + [Losses/Load]
DLF_{TLL} = 1.0065 x DLF_{DLL}

Where: Losses = $[0.0000090935 \times (SysLoad)^2] + 27.21$
Load = $-[0.00000804463 \times (SysLoad)^2] + [0.8586372 \times SysLoad] - 24.0524567$
SysLoad = SDG&E system load during hourly period in MW.

b. **Primary Voltage Class Customers**

DLF_{DLL} = 1 + (Losses/Load)
DLF_{TLL} = 1.0065 x DLF_{DLL}

Where: Losses = $[0.0000001523524 \times (SysLoad)^2] + 0.427367656$
Load = $-[0.000001181634 \times (SysLoad)^2] + [0.12612 \times SysLoad] - 3.533$
SysLoad = SDG&E system load during hourly period in MW.

c. **Primary at Substation Voltage Class Customers**

DLF_{DLL} = 1 + (Losses/Load)
DLF_{TLL} = 1.0065 x DLF_{DLL}

Where: Losses = $[0.000000000009798 \times (SysLoad)^2] + 0.007089$
Load = $-[0.0000000196 \times (SysLoad)^2] + [0.002092 \times SysLoad] - .0586$
SysLoad = SDG&E system load during hourly period in MW.

d. **Transmission Voltage Class Customers**

DLF_{DLL} = 1 + (Losses/Load) = 1
DLF_{TLL} = 1.0065 x DLF_{DLL} = 1.0065

(Continued)

SCHEDULE EECC

ELECTRIC ENERGY COMMODITY COST

DEVELOPMENT OF DWR AND UTILITY SUPPLIED ENERGY PERCENTAGES

1. Development of DWR Supplied Energy Percentages

Hourly DWR supplied energy percentages are determined by dividing DWR purchases for that hour by the total MWH scheduled in all forward markets and an estimate for real time purchases for that hour. The rate group average DWR supplied energy percentages for the billing period is determined by calculating an average of hourly DWR supplied energy percentage weighted by the utility's class hourly statistical or dynamic load profile for the applicable rate group identified in Section 4 below. The rate by consumption type categories identified in Section 4 below will be used to determine the average DWR supplied energy percentages. The average DWR supplied energy percentages are calculated on a weekly basis using all calendar weeks from the time of the customer's previous billing through the calendar week prior to the current billing. For purposes of this calculation, calendar week shall be defined as the seven day period beginning on Wednesday and ending on the following Tuesday. The average DWR supplied energy percentages are calculated each Sunday and are utilized for all billing executed through the following Saturday.

2. Development of Utility Supplied Energy Percentages

The Utility supplied energy percentage for a billing period is calculated by subtracting the DWR supplied energy percentage from 100%.

3. Summary of Class Load Profile Categories and Associated Rate Schedules

Class Load Profile	Rate Category	Associated Rate Schedules	
Residential:	Residential Non-Time-of-Use	DR, DR-LI, E-LI, DM, DS, DT, DT-RV	
	Residential Time-of-Use	DR-TOU, DR-TOU-DER	
	Electric Vehicle Time-of-Use	EV-TOU, EV-TOU-3	
	Electric Vehicle & Household TOU	EV-TOU-2	
Small Commercial:	Small Commercial	A, A-TC	
Schedule AD:	Schedule AD	AD	
Medium Commercial/ Industrial (<or=500 kW):	Medium Commercial/Industrial	A-TOU, AY-TOU, AL-TOU, AL-TOU-CP, AL-TOU-DER, PA-T-1	
Large Commercial/ Industrial (> 500 kW):	Large Commercial/Industrial	AL-TOU, AL-TOU-CP, AL-TOU-DER, PA-T-1	T
Schedule A6-TOU:	Schedule A6-TOU	A6-TOU	
Agricultural:	Agricultural Non-Time-of-Use	PA	
Lighting:	Lighting	LS-1, LS-2, LS-3, OL-1, DWL	

(Continued)

SCHEDULE EECC

ELECTRIC ENERGY COMMODITY COST

DEVELOPMENT OF DWR AND UTILITY SUPPLIED ENERGY PERCENTAGES (Continued) L

4. Summary of Average Supplied Energy Percentages Categories

Category	Consumption Type		Number of Percentages
Residential	Total	at 1 Voltage	1
Residential TOU	On-peak, off-peak	at 1 Voltage	2
Electric Vehicle TOU	On-peak, off-peak, super off	at 1 Voltage	3
Electric Vehicle & Household TOU	On-peak, off-peak, super off	at 1 Voltage	3
Small Commercial	Total	at 2 Voltage	2
Schedule AD	Total	at 2 Voltage	2
Medium Commercial/Industrial < 500 kW	On-peak, semi-peak, off-peak	at 4 Voltage	12
Medium Commercial/Industrial < 500 kW AV Rate	Semi-peak (include signal periods), off-peak	at 4 Voltage	8
Large Commercial/Industrial > 500 kW	On-peak, semi-peak, off-peak	at 4 Voltage	12
Large Commercial/Industrial > 500 kW AV Rate	Semi-peak (include signal periods), off-peak	at 4 Voltage	8
Schedule A6-TOU	On-peak, semi-peak, off-peak	at 3 Voltage	9
Agricultural	Total	at 1 Voltage	1
Agricultural TOU	On-peak, off-peak	at 1 Voltage	2
Lighting	Total	at 1 Voltage	1
		Total	66

Sixty-six percentages will be determined for each of the 9 billing period options (4-week period up to a 12-week period).

SPECIAL CONDITIONS

1. Definitions. The definitions of principle terms used in this schedule are found either herein or in Rule 1, Definitions.

2. Hourly Electric Energy Commodity Cost Rate Option. Customers may elect to purchase their electric power on an hourly basis through the utility. These customers will be required to have Interval Metering, as defined in Rule 1, at the customer's expense, and complete Form 143-01959 (6/97), Request for Hourly Pricing. Generation services provided under this schedule must be taken in conjunction with non-generation services provided under Direct Access. See Rule 24 for further details on the service requirements applicable to Hourly EECC Rate Option customers. Customers electing the Hourly EECC Rate Option will be subject to the provisions on changing rate options listed in Rule 12.

3. Service Restrictions. Service under this schedule is restricted to the entire load served by single meters. The electric load of a single meter may not be partitioned among services rendered under this schedule and services rendered by a non-utility party under Direct Access. L D

A5. BIP Program Materials

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 similar proceeding as ordered in Decision 02-04-060. 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 within thirty (30) minutes of their notice from PG&E. 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.

TERRITORY: This schedule applies everywhere PG&E provides service.

ELIGIBILITY: This schedule is available to both bundled-service and Direct Access commercial, industrial, and agricultural customers. Each customer 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. (T) (T) (N) | | (N)

(D)

Customers must submit a Demand Response Program Agreement (Form 79-976), and a Customer Agreement and Password Agreement Governing use of Internet-Based Software Agreement (Form 79-977), in order to establish service. In addition, customers must have the required metering and notification equipment in place prior to participation in the Program. (T)

A customer must designate the number of kW ("firm service level") to which it will reduce its load down to or below during a Program operation in Form 79-976. The designated firm service level must be no more than eighty-five percent (85%) of the 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 submit to PG&E a written declaration that states that the customer is, to the best of that customer's understanding, an essential customer under Commission rules and exempt from rotating outages. It must also state that the customer voluntarily elects to participate in an interruptible 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)

SCHEDULE E-BIP—BASE INTERRUPTIBLE PROGRAM
(Continued)

METERING EQUIPMENT:

Each account must have an interval meter capable of recording usage in 15-minute intervals installed that can be read remotely by PG&E. A Meter Data Management Agent (MDMA) may also read the customer's meter on behalf of the customer's Energy Service Provider (ESP), if a customer is receiving Direct Access Service. Metering equipment (including telephone line, cellular, or radio control communication device) must be in operation for at least ten (10) days prior to participating in the program. If required, PG&E will provide and install the metering equipment at no cost to the bundled service customer. The installation of an internal data meter for customers taking service under the provisions of Direct Access is the responsibility of the customer's Energy Service Provider, or their Agent, and must be installed in accordance with Electric Rule 22. (T) | (T) (N) (T) | | (N) (D)

Customers receiving an interval meter at no charge from PG&E through this Program will be able to continue to use it at no additional cost even after the Program is terminated, provided that the customer remained in the Program continuously for a minimum period of one year. A customer who receives an interval meter through this Program but later elects to leave the Program prior to the one-year anniversary date, or is terminated for cause, will reimburse PG&E for all expenses associated with the installation and maintenance of the meter. Such charges will be collected as a one-time payment pursuant to Electric Rule 2, Section I.

Direct Access Service Customers – If PG&E is the Meter Data Management Agent (MDMA) on behalf of the customer's Energy Service Provider, no additional fees will be required from the Direct Access service customer. On the other hand, if the Direct Access service customer uses a third-party MDMA, the customer will be responsible for any and all costs associated with providing the interval data into the PG&E system on a daily basis. This includes any additional metering or communication devices that may need to be installed 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 within PG&E's specification on a daily basis for a period of no less than ten (10) days to establish their baseline. (N) | | | | | | | | (N)

NOTIFICATION EQUIPMENT:

Customers, at their expense, must have access to the Internet and an e-mail address to receive notification via the Internet. In addition, all customers must have, at their expense, an alphanumeric pager that is capable of receiving a text message sent via the Internet. A customer cannot participate in the Program until all of these requirements have been satisfied.

- In the event of a Program curtailment operation, customers will be notified using one or more of the above-mentioned systems. Receipt of such notice is the responsibility of the participating customer. Once notified, the customer must log into the Program's Internet web site and acknowledge participation in the curtailment operation. Failure to acknowledge a curtailment notice does not release the customer from its obligation to participate. PG&E does not guarantee the reliability of the pager system, e-mail system or Internet site by which the customer receives notification. (T) (T)

(D)

(Continued)

SCHEDULE E-BIP—BASE INTERRUPTIBLE PROGRAM
(Continued)

PROGRAM DETAILS:

A. Program Options (N)

Customers participating in the program must elect one of the two options below which shall be designated on their Demand Response Program Agreement (Form 79-976). Customers who participate in E-BIP prior to January 27, 2005, will be automatically defaulted to Option A.

OPTION A

1. Notification Period – Customers will be given at least thirty (30) minutes notice before each curtailment.

2. Event Limits – A Program curtailment operation will be limited to a maximum of one (1) event per day and four (4) hours per event. The Program will not exceed ten (10) events during a calendar month, or one hundred twenty (120) hours per calendar year.

3. Program Participation Incentive Payments – A $7.00/kW incentive payment will be paid on a monthly basis based on the customer's monthly potential load reduction amount.

4. Failure to Reduce Loads during an Event – Customers will be penalized $6.00 per kilowatt-hour (kWh) for energy usage over its firm service level during a curtailment.

OPTION B

1. Notification Period – Customers will be given at least three (3) hours notice before each curtailment.

2. Event Limits – A Program curtailment operation will be limited to a maximum of one (1) event per day and three (3) hours per event. The Program will not exceed ten (10) events during a calendar month, or ninety (90) hours per calendar year.

3. Program Participation Incentive Payments – A $3.00/kW incentive payment will be paid on a monthly basis based on the customer's monthly potential load reduction amount.

4. Failure to Reduce Loads during an Event – Customers will be penalized $2.50 per kWh for energy usage over its firm service level during a curtailment.

B. Other Program Guidelines

1. E-BIP Events – The CAISO, based on its forecasted system conditions and operating procedures, may request PG&E to operate all or part of the customers on the Program. The Program may also be operated in the event of a transmission system contingency. (N)

(Continued)

SCHEDULE E-BIP—BASE INTERRUPTIBLE PROGRAM
(Continued)

PROGRAM DETAILS: (Cont'd.)

B. Other Program Guidelines (Cont'd.) (N)

2. Potential Load Reduction – Participants monthly potential load reduction amount during the Summer Season (May 1 through October 31) will be paid based on the difference of the customer's average monthly on-peak period demand (on-peak kWh divided by available on-peak hours) and its designated firm service level. During the Winter Season (November 1 through April 30) payments will be paid based on the difference of the customer's average monthly partial-peak period demand (partial-peak kWh divided by available partial-peak hours) and its designated firm service level. This difference will be multiplied by the appropriate incentive level to determine the monthly incentive payment.

3. PG&E will evaluate and credit customers and/or apply non-compliance penalties for the customer load reductions realized under Schedule E-BIP within a period no longer than ninety (90) days after each curtailment event, depending on where the curtailment event falls within the customer's actual billing cycle. The incentive payments will be reflected in the customer's regular monthly bill as an adjustment.

4. PG&E may elect to evaluate and assess the non-compliance penalties associated with several curtailment events as a single adjustment.

5. Customers may re-designate their firm service level or discontinue participation in the Program only once each year during the month of November. Customers shall provide written notification of such changes to PG&E. Cancellation will become effective with the first regular billing cycle following the thirty (30) days' notice.

6. The Program will be operated throughout the year.

7. In the event of a curtailment event, customers on the Program will be notified as described in the Notification Equipment Section of this schedule.

8. PG&E reserves the right to terminate the Program, with Commission approval and thirty (30) days' written notice to customers. (N)

(Continued)

SCHEDULE E-BIP—BASE INTERRUPTIBLE PROGRAM
(Continued)

(D)

INTERACTION WITH CUSTOMER'S OTHER APPLICABLE 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 California Power Authority (CPA) or a third party sponsored interruptible load program must immediately notify PG&E of such activity.

Load can only be committed to one interruptible program for any given hour of a curtailment, and customers will be paid for performance under only one program for a given load reduction.

Customers may participate in the Optional Binding Mandatory Curtailment Plan (Schedule E-OBMC), and the Pilot Optional Binding Mandatory Curtailment Plan (Schedule E-POBMC) but the customers' Maximum Load Level under those programs (T)
may not overlap their FSL. With limitations, participants in E-BIP may also participate in |
the Non-Firm Program, Demand Bidding Program (Schedule E-DBP), and the California |
Power Authority Demand Response Program (CPA DRP). Customers currently enrolled (T)
in Non-Firm program, must complete all annual obligations to that program before being eligible for E-BIP. Customers participating in E-DBP, will not receive an incentive
payment during hours where there is an overlapping E-BIP event. Customers may (T)
participate in the CPA-DRP provided their CPA-DRP interruptible load is below their E- (T)
BIP Firm Service Level.

Customers shall not participate in the Schedule Load Reduction Program (Schedule E-SLRP) or the Critical Peak Pricing Program (Schedule E-CPP) while on the E-BIP program.

Base Interruptible Program

The Base Interruptible Program, or E-BIP, is a mandatory program that pays you on a monthly incentive to reduce your load to a pre-determined amount when the California Independent System Operator (CAISO) calls day-of load curtailment notice.

How It Works

To participate in the program, you must simply identify a designated load, or "firm service level," below your average demand. Customers who participated in E-BIP prior to January 27, 2005, will be required to reduce their load to that level within 30 minutes each time a curtailment event is called. This is described in detail under Option A. New participants must elect one of two available options.

- **Option A**: Gives the customer a 30 minute notification and $7.00 per kilowatt (kw) per month incentive for the monthly load reduction amount. Failure to reduce loads during an event will result in a $6.00 charge per kilowatt hour for energy use over the firm service level.
- **Option B**: Gives the customer a three hour notification and $3.00 per kw per month incentive for the monthly load reduction amount. Failure to reduce loads during an event will result in a $2.50 charge per kilowatt hour for energy use over the firm service level.

To participate, you must commit to curtail:

- At least 15 percent of your average monthly load or a minimum of 100 kw, whichever is greater

E-BIP operations are limited to:

- **Option A**: Maximum of one event per day and four hours per event. The Program will not exceed 10 events per month, or 120 hours per year.
- **Option B**: Maximum of one event per day and three hours per event. The Program will not exceed 10 events per month, or 90 hours per year.

Incentives

As described above, incentives and penalties will depend on the option that is elected or is a result of a default (applicable to customers who participated in E-BIP prior to January 27, 2005). The customer's bill credit will be based on the difference between your selected firm service level and your monthly summer average peak demand (during the winter, it may be based on the monthly average partial peak demand).

Qualifying for E-BIP

To qualify for E-BIP the customer must meet all of the following requirements:

- Currently a Pacific Gas and Electric Company bundled-service and Direct Access commercial, industrial, and agricultural customers.
- Served under the provisions of a demand time-of-use rate schedule.
- Have an average monthly demand of at least 100 kw.
- Not participating in Pacific Gas and Electric Company's Critical Peak Program and the Scheduled Load Reduction Program while on E-BIP

If you are already participating in Pacific Gas and Electric Company's existing mandatory load curtailment demand response program, you will qualify for E-BIP once you have completed your calendar year performance requirements. Also, any loads enrolled under the CAISO's Demand Response Program will need to complete their annual performance obligations under that program before becoming eligible for E-BIP.

Equipment Requirements

The customer must have an interval meter in order to participate in E-BIP. If the customer does not have an interval meter, Pacific Gas and Electric Company will install one at no charge. Participants receiving a free meter will be required to remain in the program for one full year.

For more information about how your business can benefit from InterAct II and our demand response programs, contact your local PG&E Account Representative or call 1 (800) 468-4743.

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Schedule TOU-BIP Sheet 1 (T)
TIME-OF-USE-GENERAL SERVICE (T)
BASE INTERRUPTIBLE PROGRAM (T)

APPLICABILITY

This Schedule is optional for customers served under Time-of-Use (TOU) or Real Time Pricing (RTP) tariff provision whose monthly Maximum Demand reaches or exceeds 200 kW and who commit to curtail at least 15 percent of such customer's Maximum Demand which shall not be less than 100 kW per Period of Interruption. (T) (T)

In addition, customers who are currently receiving service under Schedules I-6, RTP-2-I, and AP-I, and request to concurrently receive service under this Schedule, are eligible when they have fulfilled their annual maximum number of interruption obligations under those schedules. (D) (T) (T)

TERRITORY (D)

Within the entire territory served.

RATES

All charges and provisions of the customer's otherwise applicable rate schedule shall apply as follows:

(D)

In accordance with the terms and conditions of this Schedule and the applicable contract(s) the customer's bill will be credited $7.10 per kW per month for voltages below 2kV, $6.95 per kW per month for voltages from 2 kV to 50 kV, and $6.70 per KW per month for voltages above 50 kV for all kW in excess of the customer's specified Firm Service Level. The bill credit will be based on the difference between the customer's monthly average peak period demand recorded during the monthly billing period and the customer's selected Firm Service Level. (T) (T)

A charge for Excess Energy may apply under certain conditions, as provided by Special Condition 6.

SPECIAL CONDITIONS

1. Interruptible Load: The Interruptible Load is the measured difference between the customer's demand, at the time of interruption, and the customer's firm service level.

2. Firm Service Level: Firm Service Level is the Maximum Demand SCE is expected to supply and/or deliver during any Period of Interruption. The Firm Service level shall be specified by the customer. During a Period of Interruption, the customer is expected to interrupt load to its specified Firm Service Level. Increases or decreases in Firm Service Level may be made no more often than once per year, upon written request by the customer between November 1 and December 1 and execution of an Amendment To Contract For Interruptible Service (Form 14-332). Customers served under this Schedule shall establish a Firm Service Level of zero or greater.

(Continued)

Schedule TOU-BIP Sheet 2 (T)
TIME-OF-USE-GENERAL SERVICE (T)
BASE INTERRUPTIBLE PROGRAM (T)
(Continued)

SPECIAL CONDITIONS (Continued)

3. Notice of Interruption: Upon notification to SCE from the Independent System Operator (ISO), of the need to implement load reductions in SCE's service territory, a Notice of Interruption can be given under this Schedule. SCE shall notify the customer to reduce the demand imposed on the electric system to the Firm Service Level. Upon receipt by a customer of a Notice of Interruption from SCE, the customer shall reduce the demand imposed on the electric system to the Firm Service Level within 30 minutes.

4. Period of Interruption: A Period of Interruption is a time interval which commences thirty minutes after Notice of Interruption and which ends upon notification by SCE of the end of Period of Interruption.

5. Excess Energy: The number of kWh consumed in a Period of Interruption which exceeds the product of the Firm Service Level kW multiplied by the total number of hours of Interruption, shall be considered Excess Energy.

6. Charges for Excess Energy: For each Period of Interruption during which the customer fails (I)
to interrupt and hence incurs Excess Energy, a $10.64895 per kWh penalty for voltages (T)
below 2kV, and $10.42129 for voltages from 2kV to 50 kV, and $10.05518 for voltages above (T)
50 kV shall be added to the customer's billing as otherwise provided in this Schedule.

(N)
7. Termination of Interruptible Service: Failure to respond to two valid Notices of Interruption |
within a 12-month period shall result in termination of interruptible service under this Schedule |
beginning with the next regularly scheduled meter read date following the second failure to (N)
respond.

(T)
8. Required Metering and Communication Equipment: Metering and Communication equipment, as specified by SCE, will be installed, owned, and maintained in accordance with SCE specifications, including such facilities not located on the customer's property. These facilities will be solely under operational control of SCE unless otherwise specified by SCE. If required, SCE will provide and install metering equipment at no charge to the customer. However, a customer receiving metering equipment at no charge who terminates service under this Schedule for any reason before one full year, shall pay back to SCE the costs associated with the installation and maintenance of the metering equipment.

(T)
9. Contracts: A contract is required for service under this Schedule. To be served under this Schedule, eligible customers shall comply with all provisions of the contract within 30 days of contract execution. Customers shall have a one month window each year between November 1 and December 1, to provide written notice to SCE to terminate service or to increase or decrease their Firm Service Level under this Schedule. Additionally, during this one month window, a customer receiving service concurrently under both this Schedule and under Schedule I-6 may select which Schedule under which it shall receive service during the following year. If no selection is made, service will be terminated under this Schedule and the customer will continue to receive service under Schedule I-6 as of January 1 of the next calendar year. However, a customer receiving metering equipment at no charge as defined in Special Condition 8, must remain on this Schedule for one full year. Customers shall not be permitted to prematurely terminate service hereunder for reasons that changes in electrical demand requirements may otherwise preclude them from taking service under this Schedule.

(Continued)

Schedule TOU-BIP Sheet 3 (T)
TIME-OF-USE-GENERAL SERVICE (T)
BASE INTERRUPTIBLE PROGRAM (T)
(Continued)

SPECIAL CONDITIONS (Continued)

10. Number and Duration of Interruption: The number of Periods of Interruption will not exceed one (1) per day, ten (10) in any calendar month, and a total of 120 hours per calendar year. The duration of each Period of Interruption will not exceed 4 hours. (T)

11. Customer Electrical Generating Facilities: (T)

a. Where customer electrical generating facilities are used to meet a part or all of the customer's electrical requirements, service shall be provided concurrently under the terms and conditions of Schedule S and this Schedule. Parallel operation of such generating facilities with SCE's electrical system is permitted. A generation interconnection agreement is required for such operation.

b. Customer electrical generating facilities used solely for auxiliary, emergency, or standby purposes (auxiliary/emergency generating facilities) to serve the customer's load during a period when SCE's service is unavailable and when such load is isolated from the service of SCE are not subject to Schedule S. However, upon approval by SCE, momentary parallel operation may be permitted in order for the customer to avoid interruption of load during a Period of Interruption or to allow the customer to test the auxiliary/emergency generating facilities. A generation interconnection agreement is required for such momentary parallel operation.

12. Relationship to Other Programs. Load can only be committed to one program, and (T)
participants paid only once for a load reduction. With limitations, participants in TOU-BIP may (T)
also participate in I-6, Demand Bidding Program (Schedule DBP), and the California Power Authority Demand Reserves Partnership Program (CPA DRP). Customers enrolled in DBP or the CPA DRP Supplemental Energy Market option will not receive an incentive payment during hours where there is an overlapping TOU-BIP event. Customers may participate in the (T)
CPA-DRP reservation payment options provided their CPA-DRP interruptible load is below their TOU-BIP Firm Service Level. In addition, Customers on this Schedule shall not participate in the ISO's Ancillary Services Load Program.

(Continued)

Schedule TOU-BIP Sheet 4 (T)
TIME-OF-USE-GENERAL SERVICE (T)
BASE INTERRUPTIBLE PROGRAM (T)
(Continued)

SPECIAL CONDITIONS (Continued)

13. Insurance. Insurance may not be used to pay non-compliance penalties for willful failure to comply with a Notice of Interruption. Existing and new customers will not be eligible for continued service or new service under this Schedule unless a declaration is signed under penalty or perjury which states that the customer does not have, and will not obtain, any insurance for the purpose of the insurance paying non-compliance penalties for willful failure to comply with Notices of Interruptions. Continued eligibility and new eligibility under this Schedule will require that each customer execute a declaration stating that it does not have, and will not obtain, such insurance. For any customer with such insurance after the effective date of this Special Condition, service under this Schedule will be terminated and such customer will be required to pay back the interruptible rate discounts 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 this Schedule. (T)

14. Essential Use Customers. Customers electing to receive service under this Schedule and who are classified as Essential Use in accordance with Commission Decision No. 91548 must provide proof of back-up generation or other means to supply energy for interruptible load. A declaration must be signed under penalty of perjury and must state that the customer is, to the best of that customer's understanding, an Essential Use customer under Commission rules. It must also state that the customer voluntarily elects to participate in an interruptible program for part of or all of its load upon request by SCE, while continuing to meet its essential needs based on adequate back-up generation or other means. Furthermore, such customer must set its Firm Service Level at no less than 50 percent of its load. Absent such declaration, SCE may find the customer ineligible to receive service under this Schedule. (T)

15. Customers with Service Metered and Delivered at Voltages above 50 kV (Sub-transmission customers) Included in Rotating Outages. (T)

Sub-transmission customers, except for those customers exempt from rotating outages, are to be included in controlled, rotating outages when required by the Independent System Operator (ISO). To the extent feasible, SCE will coordinate rotating outages applicable to Sub-transmission customers who are fossil fuel producers and pipeline operators and users to minimize disruption to public health and safety. SCE shall not include a Sub-transmission customer in an applicable rotating outage group if the customer's inclusion would jeopardize electric system integrity. Sub-transmission customers who are not exempt from rotating outages, and seek such exemption, may submit an Optional Binding Mandatory Curtailment (OBMC) Plan to SCE in accordance with Schedule OBMC. If SCE approves a customer's OBMC Plan, the customer will become exempt from rotating outages and will be subject to the terms and conditions of Schedule OBMC and its associated contract.

Non-exempt Sub-transmission customers shall be required to drop their entire electrical load during applicable rotating outages by either (1) implementing the load reduction on their own initiative, in accordance with subsection a, below; or (2) having SCE implement the load reduction through remote-controlled load drop equipment (control equipment) in accordance with subsection b, below. A Sub-transmission customer shall normally be subject to the provisions of subsection a. If SCE approves a customer's request to have SCE implement the load reduction or if the customer does not comply with prior required load reductions, as specified in subsection c, the customer will be subject to the provisions of subsection b.

(Continued)

Schedule TOU-BIP Sheet 5 (T)
TIME-OF-USE-GENERAL SERVICE (T)
BASE INTERRUPTIBLE PROGRAM (T)
(Continued)

SPECIAL CONDITIONS (Continued)

15. Customers with Service Metered and Delivered at Voltages above 50 kV (Sub-transmission customers) Included in Rotating Outages. (Continued) (T)

a. Customer-Implemented Load Reduction.

(i) Notification of Required Load Reduction. At the direction of the ISO, SCE shall notify each Sub-transmission customer in an affected rotating outage group to drop its entire load. Within 30 minutes of such notification, the customer must drop its entire load. The customer shall not return the dropped load to service until 90 minutes after SCE sent the notification to the customer to drop its load, unless SCE notifies the customer that it may return its load to service prior to the expiration of the 90 minutes.

(ii) Method of Notification. SCE will notify Sub-transmission customers who are required to implement their own load reduction via telephone, by either an automated calling system or a manual call to a business telephone number or cellular phone number designated by the customer. The designated telephone number will be used for the sole purpose of receiving SCE’s rotating outage notification and must be available to receive the notification at all times. When SCE sends the notification to the designated telephone number the customer is responsible for dropping its entire load in accordance with subsection a. (i), above. The customer is responsible for informing SCE, in writing, of the telephone number and contact name for purposes of receiving the notification of a rotating outage.

(iii) Excess Energy Charges. If a Sub-transmission customer fails to drop its entire load within 30 minutes of notification by SCE, and/or fails to maintain the entire load drop until 90 minutes after the time notification was sent to the customer, unless SCE otherwise notified the customer that it may return its load to service earlier in accordance with subsection a. (i) above, SCE shall assess Excess Energy Charges of $6 per kWh for all kWh usage in excess of the Authorized Residual Ancillary Load. Such charges will be based on the total kWh usage during the applicable rotating outage penalty period, less the product of Authorized Residual Ancillary Load in kW and the applicable rotating outage penalty period in hours. Excess Energy Charges will be determined and applied by SCE subsequent to the Sub-transmission customer’s regularly scheduled meter read date following the applicable rotating outage.

(Continued)

Schedule TOU-BIP Sheet 6 (T)
TIME-OF-USE-GENERAL SERVICE (T)
BASE INTERRUPTIBLE PROGRAM (T)
(Continued)

SPECIAL CONDITIONS (Continued)

15. Customers with Service Metered and Delivered at Voltages above 50 kV (Sub-transmission customers) Included in Rotating Outages. (Continued) (T)

a. Customer-Implemented Load Reduction. (Continued)

(iv) Authorized Residual Ancillary Load. Authorized Residual Ancillary Load is load that is deemed to be equivalent to five percent of the Sub-transmission customer's prior billing month's recorded Maximum Demand. This minimum load level is used as a proxy to allow for no-load transformer losses and/or load attributed to minimum grid parallel operation for generators connected under Rule 21.

b. SCE-Implemented Load Reduction.

Non-exempt Sub-transmission customers may request, in writing, to have SCE drop the customer's entire load during all applicable rotating outages using SCE's remote-controlled load drop equipment (control equipment). If SCE agrees to such arrangement, SCE will implement the load drop by using one of the following methods:

(i) Control Equipment Installed. For a Sub-transmission customer whose load can be dropped by SCE's existing control equipment, SCE will implement the load drop during a rotating outage applicable to the customer. The customer will not be subject to the Notification and Excess Energy Charge provisions set forth in subsection a, above.

(ii) Control Equipment Pending Installation. For a Sub-transmission customer whose load can not be dropped by SCE's existing control equipment, the customer must request the installation of such equipment at the customer's expense in accordance with SCE's Rule 2, Section H, Added Facilities. Pending the installation of the control equipment, the customer will be responsible for dropping load in accordance with the provisions of subsection a, above, including the Notification and Excess Energy Charge provisions.

c. Non-compliance: A non-exempt Sub-transmission customer subject to subsection a, above, who fails to drop load during three rotating outages in a three year period to a demand level of 20% or less of the customer's prior billing month's recorded Maximum Demand averaged over the applicable rotating outage period, is not in compliance with this tariff. The three year period shall commence with the first failure to drop load as specified in this subsection. A customer not in compliance with this condition will be placed at the top of the Sub-transmission customer rotating outage group list and will be expected to comply with subsequent applicable rotating outages. In addition, the customer must select one of the two options below within fifteen days after receiving written notice of non-compliance from SCE. A customer failing to make a selection within the specified time frame will be subject to subsection c. (ii) below.

(Continued)

Schedule TOU-BIP — Sheet 7 (T)
TIME-OF-USE-GENERAL SERVICE (T)
BASE INTERRUPTIBLE PROGRAM (T)
(Continued)

SPECIAL CONDITIONS (Continued)

15. Customers with Service Metered and Delivered at Voltages above 50 kV (Sub-transmission customers) Included in Rotating Outages. (Continued) (T)

c. Non-compliance: (Continued)

(i) Subject to Schedule OBMC: The customer shall submit an OBMC Plan, in accordance with Schedule OBMC, within 30 calendar days of receiving written notice of non-compliance from SCE. Pending the submittal of the OBMC Plan by the customer and pending the review and acceptance of the OBMC Plan by SCE, the customer will remain responsible for dropping load in accordance with the provisions of subsection a, above, including the Notification and Excess Energy charge provisions. If the customer fails to submit an OBMC Plan within 30 days of receiving notice of non-compliance from SCE, or if the customer's OBMC Plan is not approved by SCE, or if the customer fails to meet the requirements of Schedule OBMC once the OBMC Plan is approved, the customer shall be subject subsection c. (ii), below.

(ii) Installation of Control Equipment. The customer shall be subject to the installation of control equipment at the customer's expense in accordance with SCE's Rule 2, Section H, Added Facilities, if such equipment is not currently installed. If such switching capability is installed, SCE will drop the customer's load for all applicable subsequent rotating outages in accordance with the provisions of subsection b, above. Pending the installation of control equipment, the customer will remain responsible for dropping load in accordance with the provisions of subsection a, above, including the Notification and Excess Energy Charge provisions.

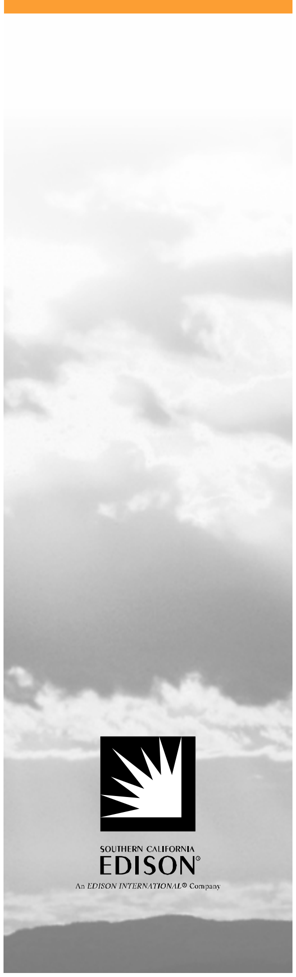
d. Net-Generators

Sub-transmission customers who are also net-generators are normally exempt from rotating outages, but they must be net suppliers of power to the grid during all rotating outages. For the purpose of this Special Condition, a net-generator is an SCE customer who operates an electric generating facility as part of its industrial or commercial process, and the generating facility normally produces more electrical power than is consumed in the industrial or commercial process, with the excess power supplied to the grid. Sub-transmission customers whose primary business purpose is to generate power are not included in this Special Condition.

(i) Notification of Rotating Outages. SCE will notify sub-transmission customers who are net-generators of all rotating outages applicable to customers within SCE's service territory. Within 30 minutes of notification, the customer must ensure it is a net supplier of power to the grid throughout the entire rotating outage period. Failure to do so will result in the customer losing its exemption from rotating outages, and the customer will be subject to Excess Energy Charges, as provided below.

(ii) Excess Energy Charges. Net generators who are not net suppliers to the grid during each rotating outage period will be subject to Excess Energy Charges of $6 per kWh for all kWh usage in excess of the Authorized Residual Ancillary Load. Such charges will be based on the total kWh usage during a rotating outage penalty period, less the product of Authorized Residual Ancillary Load in kW and the applicable rotating outage period hours. Excess Energy Charges will be determined and applied by SCE subsequent to the customer's regularly scheduled meter read date following the applicable rotating outage. Excess Energy Charges shall not apply during periods of verifiable scheduled generator maintenance or if the customer's generator suffers a verifiable forced outage. The scheduled maintenance must be approved in advance by either the ISO or SCE, but approval may not be unreasonably withheld.

TIME-OF-USE BASE INTERRUPTIBLE PROGRAM (TOU-BIP)



What is the Time-of-Use Base Interruptible Program (TOU-BIP)?

Schedule TOU-BIP is an interruptible program open to customers who have monthly demands greater than 200 kW in any three months during the preceding 12 months. Customers must commit to reducing at least 15% of their maximum demand, which cannot be less than 100 kW, and customers must select a Firm Service Level (FSL). When SCE sends notification to a TOU-BIP customer of an interruption event, the customer is required to reduce their electrical usage to their specified FSL within 30 minutes of notification being sent.

In exchange, customers receive a monthly credit based on the difference between their average peak period demand for each month and their selected FSL. TOU-BIP credits for each billing period will be calculated and applied to the following month's bill. Penalties apply for failure to reduce power to no more than the customer's determined FSL within 30 minutes of notification being sent.

Existing I-6 customers may also participate in schedule TOU-BIP, but they will only become eligible for TOU-BIP credits after they have met all of their annual I-6 interruption obligations.

Who is eligible?

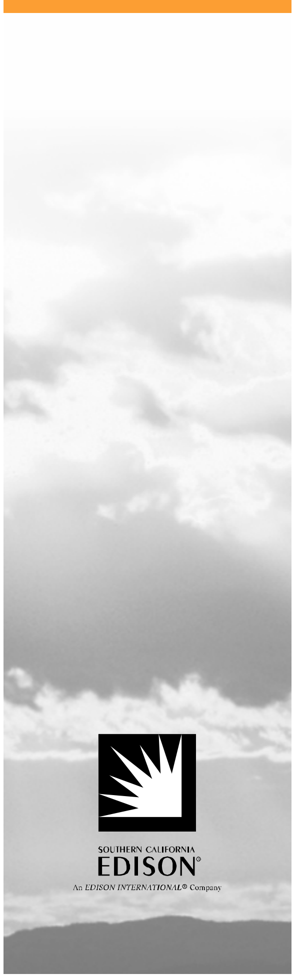
The TOU-BIP is available to customers eligible for service under the General Service Rate Schedule, whose monthly maximum demand exceeds 200 kW. With limitations, TOU-BIP is also available to existing I-6, Demand Bidding Program (DBP), and California Demand Reserves Partnership (Cal-DRP) participants.

TOU-BIP is not compatible with any Critical Peak Pricing (CPP) Program or the California Independent System Operator's (CAISO) Ancillary Services Load Program.

CUSTOMER OBLIGATIONS

Customers taking service under TOU-BIP must agree to the following conditions:

- **Firm Service Level (FSL):** The FSL is the amount of electricity a TOU-BIP customer determines is necessary to meet their operational requirements during a TOU-BIP event. TOU-BIP customers are required to reduce electrical load to their designated FSL or "non-interruptible" level within 30 minutes of notice being sent to their dedicated phone line. In exchange for agreeing to reduce electrical usage to their designated FSL, SCE provides participating customers with a bill credit based on the difference between the customer's monthly average peak period demand and the customer's FSL. Essential Use customers cannot set their FSL to less than 50% of their average peak load. TOU-BIP customers may change their FSL during the annual November 1 to December 1 window.



- **Telephone Lines:** TOU-BIP customers must install one dedicated, unlisted telephone line and telephone for the sole purpose of receiving official TOU-BIP event notifications. The dedicated telephone line must:
  - — *NOT have dial out capability.* Because its only purpose is to receive calls from SCE, NO other calls should be made to or from this line. **Cellular phones are not acceptable.**
  - — *Be an unlisted telephone number.* Only SCE calls should be received on this line.
  - — *Be a direct line.* Calls cannot go through a switchboard or voicemail system.
  - — *Be located in an area where it can be answered immediately AT ALL TIMES.*
- Interruption Frequency and Duration: An interruption event may occur as early as 30 minutes after SCE receives such request from the CAISO. The CAISO will direct SCE to reduce a specific amount of electrical load. SCE will then notify its interruptible customers to reduce electrical usage to their FSL within 30 minutes of receiving the notification to avoid penalties.
- TOU-BIP interruption events are limited to:
  - — No more than one 4-hour event per day, or
  - — No more than 10 events per calendar month, or 120 hours per calendar year.

The CAISO can call for an interruption event AT ANY TIME – 24 hours per day, 7 days per week, 365 days per year.

TOU-BIP customers who fail to respond to two notices of interruption, in any 12-month period, will be terminated from TOU-BIP during the next Opt-Out Window, and all charges of their Otherwise Applicable Tariff shall apply.

- **SCE's Communicating Interval Meter** — capable of recording usage in 15-minute intervals. If the customer does not already have a communicating interval meter, SCE will provide and install one at no charge (certain restrictions apply).
- **One Dedicated Telephone Line and Telephone** — to receive the official notices of interruption (see details under "Customer Obligations - Telephone Lines"). The customer is responsible for providing the telephone and telephone service.

PENALTIES

Penalties, or "Excess Energy Charges," may be applied each time a customer fails to reduce their electrical usage to their FSL during an interruption event. Interruptible customers have 30 minutes from the time notification is sent to fully comply with the request to interrupt to their FSL.

What are Bill Credits?

The amount by which the electric rate is reduced for those participating in SCE's TOU-BIP program depends on:

- the demand the customer places on SCE's system,
- the time of day and season when the customer uses energy, and
- the amount of electricity used above and beyond the customer's designated FSL.

The customer's electrical usage is billed on a time-of-use rate, such as TOU-GS2.

TOU-BIP customers will be paid a credit, even when there are no requests to interrupt. The credit is applied to the kW difference between each month's average peak period demand and the customer's designated FSL. The average monthly peak period demand is the sum of the kWh consumed in the peak period (on-peak for summer and mid-peak for winter) divided by the number of hours in the period that month. TOU-BIP credits for each billing period will be calculated and applied to the following month's bill.

This fact sheet is meant to be an aid to understanding SCE's pricing schedules. It does not replace the tariffs. Please refer to the individual rate schedule of interest for a complete listing of terms and conditions of service, which can be viewed online at ***www.sce.com.***

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CONTRACTUAL REQUIREMENTS

A separate, signed *Contract for Interruptible Service* (Contract) designating the customer's FSL and other information is required for each service account that will take part in the TOU-BIP. The Contract is available through the customer's SCE representative. TOU-BIP customers may request to opt-out or adjust their FSL during the annual November 1 to December 1 window. Changes made during the opt-out window become effective on the next scheduled meter read date following verification of the request.

How do I sign up for the TOU-BIP?

To sign up for this program, customers should contact an SCE representative, or call the DRP Hotline at (626) 302-8320.

How can I receive additional interruption information?

As a courtesy, SCE provides additional Interruptible Program Status resources. *(In rare cases when we experience rapid interruptible information changes, it may cause a delay to our manual process of posting to any of our systems. In these situations, every effort is made to provide this information as quickly as possible.)*

- **Interruptible Program Status Telephone Line (888) 334-7764,** available 24 hours a day, 7 days a week, 365 days a year
- **Web site for Interruptible Program http://www.sce.com/I-6**
- **E-mail Notification**
- **Pager Notification**

Note: TOU-BIP customers MAY NOT substitute the use of these additional courtesy interruptible program information services listed above as an alternative method of receiving SCE's notices of interruption. These services are provided purely for reference purposes and are ***not alternatives to the dedicated telephone line****. Failure to answer a call from SCE on the dedicated telephone line which notifies the customer of an interruption could result in a failure to interrupt, and may result in penalties for not complying with a notice of interruption, as described in tariff schedule TOU-BIP.*

PROCURING POWER FROM ANOTHER PROVIDER

Customers currently procuring power from another provider [third-party provider, or Energy Service Provider (ESP)] will continue to be billed for the non-generation charges through the applicable SCE TOU rate schedule, while their generation cost component will be billed according to the terms and charges agreed upon with their ESP.

FOR MORE INFORMATION

SCE offers several programs to assist customers in the management of their electricity costs, such as rebates, incentives, energy surveys, and payment options. If you have questions regarding TOU-BIP or any other SCE program, call **(800) 990-7788,** contact your SCE representative, or visit www.sce.com/drp to go directly to the Time-of-Use Base Interruptible Program.

SOUTHERN CALIFORNIA EDISON

An *EDISON INTERNATIONAL*® Company

Time-of-Use Base Interruptible Program (TOU-BIP)

May 2005

Customer Benefits

- Lower operating costs
- Customers receive up front bill credit based on interruptible power available each month
- Monthly credits
  - Below 2 kV = $7.10/kW
  - 2 kV - 50 kV = $6.95/kW
  - Above 50 kV = $6.70/kW
- TOU-BIP credits for each billing period are applied to following month's bill.

Program Eligibility

- Demand Bidding Program customers can participate but cannot be paid for same load reduction

- Applicable to customers >200 kW, such as TOU-GS-2 and TOU-8
  - Existing I-6 and RTP-2-I customers may participate <u>but</u> only after annual obligations to those programs are fulfilled

- Customers subject to substantial penalties if power not reduced to a level equal to or less than their Firm Service Level (FSL), within 30 minutes of a notice of interruption

How Does It Work?

- ISO notifies SCE of need to reduce load, caused by Stage 2 Emergency (reserves below 5%), transmission line constraints, or other constraints
- SCE notifies customer to reduce power to their designated FSL within 30 minutes of notification, to avoid substantial penalties if they do not reduce power to a level equal to or less than their FSL
- The dedicated telephone is the official means of transmitting an interruption event notification
  - Dedicated telephone line must:
    - be an unlisted number
    - be a direct line (no voicemail or switchboard)
    - have no dial-out capability
    - <u>not</u> be a mobile (cell) phone
    - be located in an area where it can be answered at all times
- Customers must commit to reduce at least 15% of their maximum demand, which cannot be less than 100 kW

Firm Service Level

- The Firm Service Level (FSL) is the minimum electrical demand that a customer determines is necessary to meet basic operational requirements during an interruption event

- “Essential Use” customers cannot set their FSL at less than 50% of their average peak load

How Long Are the Interruptions?

- Interruptions are limited to:
  - One event per day
  - No more than 4 hours per event
  - 10 events per calendar month
  - 120 hours per calendar year

Interruptions can occur at any time, 7 days a week, 24 hours a day, 365 days a year.

- A customer who fails to respond to two valid Notices of Interruption within a 12-month period will be terminated from service on TOU-BIP
  - If a customer fails to respond to a Notice of Interruption, the customer will receive a warning letter
  - If a customer fails to respond to a second Notice of Interruption, customer will receive a letter of termination indicating that customer will be terminated from the program effective with the next annual opt-out period
  - Customers must comply with terms of interruption until termination from the program becomes effective

Credit

- Credit given each month for all kW exceeding customer's designated FSL

- Credit calculated from difference between customer's monthly average peak period demand and customer's designated FSL

- Average peak period demand calculated by totaling all peak period kWh and dividing by on-peak hours in summer months or dividing by mid-peak hours in winter months
  - An Example:
    - Customer's monthly average peak period demand = 1,000 kW
    - Customer's designated Firm Service Level = 200 kW
    - Credit
      - 1,000 kW – 200 kW = 800 kW x $7.10 = $5,680

Penalty

- Penalties ("Excess Energy Charges") apply to all kWh consumed above designated FSL and vary according to voltages:
  - Below 2 kV = \$10.65 per kWh
  - 2 kV – 50 kV = \$10.42
  - Above 50 kV = \$10.06

- Penalty calculation:
  - kWh consumed above product of FSL multiplied by number of hours of interruption

Penalty

- An Example

Customer Firm Service Level	Number of Hours of Interruption	kWh Consumed During Interruption
300	2 hours	800 kWh

- Step 1: Convert FSL kW into FSL kWh
    - 300 FSL kW x 2 hours of interruption = 600 kWh
- Step 2: Determine excess kWh
    - 800 kWh – 600 kWh = 200 kWh
- Step 3: Calculate penalty
    - 200 kWh x $10.65/kWh penalty = $2,130 penalty

How Do I Sign-Up?

- Customer must complete the Contract for Interruptible Service (Form PD 14-315):
  - Designate FSL
  - Sign and return to Account Manager
  - Account Manager will mail completed Contract to DRP Administrator, SCE Tariff Programs & Services (TP&S) Rosemead Office, GO1/Quad 1-A, Attn: Large Interruptible Programs
- Customer must install and pay for a dedicated telephone line and an unlisted telephone number for the sole purpose of receiving interruption notices

Contacts

- Program-related questions: DRP Hotline (626) 302-8320
- Program Status: 1-800-334-7764, or www.sce.com/drp
- TOU-BIP Helpline: (626) 302-8349

SCHEDULE BIP

BASE INTERRUPTIBLE PROGRAM

APPLICABILITY

Applicable to all time-of-use metered customers who can commit to curtail at least 15% of Monthly Average Peak Demand, with a minimum load drop of 100 kW and who request service on this schedule and comply with Special Condition 12. Service on this Rate Schedule is to be taken in combination with another generally available tariff other than for Schedule AL-TOU-CP with the exception set forth in Special Condition 13.

TERRITORY

Within the entire territory served by the Utility.

RATES

Option A:	Committed Load Incentive:	$7/kW/Mo	
	Excess Energy Usage Charge:	$6/kWh	T
Option B:	Committed Load Incentive:	$3/kW/Mo	
	Excess Energy Usage Charge:	$2.50/kWh	T

SPECIAL CONDITIONS

1. Definitions: The Definitions of terms used in this schedule are found either herein or in Rule 1.

2. Committed Load: Is the difference between the customer's recorded Monthly Average Peak Demand less the customer's selected Firm Service Level, as shown in the Customer's Base Interruptible Program Contract (Form 142-05207).

3. Committed Load Incentive Payment: Is determined by multiplying Committed Load by Committed Load Incentive. This credit will be applied to the bill of the customer on their otherwise applicable rate within 90 days of the Interruptible Period. The customer's total bill for service, including the Committed Load Incentive Payment, shall always be a positive value, or zero. Committed Load Incentive shall be zero if the Committed Load is less than 100kW or less than 15% of the customer's recorded Monthly Average Peak Demand.

4. Excess Energy Usage: Is the amount of energy used by the customer during any 15 minute interval of an Interruptible Period that is in excess of the customer's selected Firm Service Level.

5. Excess Energy Usage Charge: Customer shall pay a charge multiplied by Excess Energy Usage. This charge will be applied to the bill of the customer on their otherwise applicable rate within 90 days of the Interruptible Period. T

6. Monthly Average Peak Demand: Solely for the purpose of this tariff, Monthly Average Peak Demand is the average hourly demand recorded between the hours of 11:00 AM and 6:00 PM Monday through Friday, excluding holidays, during a calendar month.

(Continued)

SCHEDULE BIP

BASE INTERRUPTIBLE PROGRAM

SPECIAL CONDITIONS (Continued)

7. Firm Service Level: Customer's maximum expected level of demand, as specified by the customer in the Base Interruptible Program Contract (Form 142-05207), during any hour of an Interruptible Period. Customers may change their Firm Service Level or discontinue participation in the Program only once per year, by written notification to the Utility, and during the month of November. Such changes will become effective the following January 1. Customers who join the program by April 30, 2005 receive a one time waiver of the one year enrollment requirement.

8. Interruptible Period: Shall be the period of time during which the utility has informed the customer to interrupt load by use of a communications process utilizing equipment as described in Special Condition 14. The Utility will coordinate with the customer the manner of communications and provision of the interruption notice to the customer. Customer is responsible for assuring that any communications process is not interfered with in any manner. Customer is responsible to respond to the communications in a manner consistent with this tariff. If the Utility initiates communications indicating that an interruption period is occurring and other customers have received the communications then the customer shall be deemed to have received the communications if the Utility can verify that it initiated the communications to the customer. The Utility may call for an Interruptible Period any time the Independent System Operator asks the Utility to do so provided the Interruptible Period shall commence within 30 minutes (Option A) or 3 hours (Option B) after the Utility initiates communications to the customer.

9. Limitation of Interruptible Periods: For customers participating in Option A, the Interruptible Periods shall not exceed four (4) hours for any calendar day, nor 10 Interruption Periods per calendar month, nor 120 hours during any calendar year. Interruptible Periods for customers participating in Option B shall not exceed three (3) hours for any calendar day, nor ten (10) events during a calendar month, or ninety (90) hours per calendar year.

10. Limitations of Availability. This Schedule shall be limited as to its availability to customers based on any limitations the Utility has in getting communications systems in place. The Utility will man up as quickly as practical to provide this service to as many customers as quickly as practical so long as communications are in place before service commences.

11. Termination of Schedule: This Schedule is in effect until modified or terminated in the rate design phase of SDG&E's next general rate case or similar proceeding.

12. Qualifying Customer: A customer must complete a Base Interruptible Program Contract (Form 142-05207) in order to receive service on this Rate Schedule. The Utility may request the customer demonstrate to Utility's satisfaction that the customer has the capability to reduce load to their Firm Service Level during an Interruptible Period. This Rate Schedule is further limited as set forth in Special Condition 8.

13. Multiple Program Participation: Any customer that is being compensated through participation in any other Demand Response Program for the Committed Load as defined in this Rate Schedule may participate in other Demand Response Programs, but will not be permitted to receive multiple program incentives, except as specifically provided as follows. Customers can participate in the California Power Authority's DRP and receive a reservation payment for additional load below the BIP Firm Service Level as designated in the BIP Contract. Customers can participate in the California Power Authority's Supplemental Energy Market option as long as no energy payments from the Supplemental Energy Market option are made during a BIP event. A Customer taking service on this Rate Schedule may not participate in the 20/20-TOU (C&I Peak Day 20/20) or California ISO's Ancillary Services Load Program. Customers on Schedule AL-TOU-CP may take service on this Rate Schedule in combination with that Rate Schedule if they receive communications from the Utility that they have reached the maximum amount of interruptions on that Rate Schedule. The Utility's communications will indicate that they will no longer be eligible for the combined service once interruptions could again occur on that Rate Schedule. Customers can take service on Schedule DBP and on this Rate Schedule but will not receive an incentive payment during hours when there is an overlapping BIP event.

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SCHEDULE BIP

BASE INTERRUPTIBLE PROGRAM

SPECIAL CONDITIONS (Continued)

14. Metering Requirement: Customer's electric meter must be an interval data recorder with related telecommunications capability, compatible with the Utility's meter reading and telecommunications systems. Metering and telephone equipment must be in operation for at least 10 days prior to participating in the program to establish baseline. If required, the Utility will provide and install the metering equipment at no cost to the customer.

    The customer is responsible for the installation and monthly fees associated with telephone equipment and a dedicated line if such equipment is required for the remote reading or monitoring of the interval meter. Customers receiving an interval meter from the Utility through this Program will be able to continue to use it at no additional cost even after the Program is terminated, provided that the customer remains in the Program continuously for a minimum period of one year. A customer who receives an interval meter through this Program but later elects to leave the Program prior to the one-year anniversary date, will reimburse the Utility for all expenses associated with the installation and maintenance of the meter. Pursuant to Electric Rule 2, Section I, such charges will be collected as a one-time payment.

15. Notification Equipment: Customers, at their expense, must have access to the Internet and an e-mail address to receive notification via the Internet. In addition, all customers must have, at their expense, an alphanumeric pager that is capable of receiving a text message sent via the Internet. A customer cannot participate in the Program until all of these requirements have been satisfied.

    In the event of a Program curtailment operation, customers on the Program will be notified using one or more of the above-mentioned systems. Receipt of such notice is the responsibility of the participant. Once notified, the customer must log into the Program's Internet web site and acknowledge participation in the curtailment. Failure to acknowledge a curtailment notice does not release the customer from its obligation to participate. The Utility does not guarantee the reliability of the pager system, e-mail system or Internet site by which the customer received notification.

16. Insurance: Insurance may not be used to pay Excess Energy Usage Charge for willful failure to comply. Each customer must provide the utility with an executed declaration that states "I do not have, and will not obtain, insurance to compensate me in any way for any portion of the bills associated with the Excess Energy Usage Charge." Such declaration (Form 142-05209) must be on file with the utility within 30 days of the effective date of the tariffs or the customer will immediately be terminated from service under Schedule BIP. T T

17. Advance Notification: Customers who choose Option A will be notified 30 minutes in advance of the Base Interruptible Program Event. Customers who choose Option B will receive notification 3-hours in advance of the Base Interruptible Program Event.

Base Interruptible Program

The Base Interruptible Program (BIP) pays participants a monthly capacity payment in return for pre-determined load reduction when the California Independent System Operator (CAISO) initiates a Stage two firm load curtailment.

How It Works

To participate in the program, you simply identify a designated load level, or "firm service level," below your monthly average peak demand and then reduce your load to that level each time a curtailment event is called.

There are two options for participation:

	Option A	Option B
Notification:	30 minutes	three hours
Hours per day:	4	3
Days per month	10	10
Hours per year	120	90
Incentive per kW	$7	$3

To participate, you must commit to curtail at least 15 percent of your average monthly load or a minimum of 100 kilowatts, whichever is greater.

As an incentive for participating in BIP, you will receive monthly, either $7 or $3 per pledged kW reduction paid year-round Your bill credit will be based on the difference between your selected firm service level and your monthly average peak demand. If you do not comply with the requirements, you will be penalized $6 per kWh if you elect option (a), or $2.50 per kWh if you elect option (b) for energy used over your firm service level during a curtailment event.

Eligibility

Businesses that can reduce electric load by at least 15% of their monthly average peak demand or a minimum of 100 kilowatts (kW), whichever is greater, are eligible.

Other Benefits

SDG&E's Technical Assistance and Technology Incentive Program also provides assistance in determining your demand response potential and incentives for equipment that enhances your ability to respond to requests for on-peak demand reductions.

BIP Participants may be eligible to participate in other demand response programs, but restrictions do apply, and participants cannot receive incentives from more than one program for the same load reduction.

For more details on Base Interruptible Program, contact your SDG&E Account Executive, call 866-377-4735 or email

Related Information
kWickview
Default CPP Rates
Contact DRP
Demand Response Overview Brochure
Energy Management Pyramid
Demand Response FAQs

drp@semprautilities.com

Click here for a copy of the BIP contract.

Click here to view the BIP tariff.

This program is available throughout California and is offered by the state's investor owned utilities.

A6. OBMC Program Materials

SCHEDULE E-OBMC—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.

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. (T)

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SCHEDULE E-OBMC—OPTIONAL BINDING MANDATORY CURTAILMENT PLAN
(Continued)

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. (T) (N)

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 10 similar days, excluding days when the customer was paid to reduce load under PG&E's Demand Bidding 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.

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 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.

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.

(Continued)

SCHEDULE E-OBMC—OPTIONAL BINDING MANDATORY CURTAILMENT PLAN
(Continued)

PROGRAM OPERATIONS: (Cont'd.)

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. (N)

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. An OBMC Plan may 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)

SCHEDULE E-OBMC—OPTIONAL BINDING MANDATORY CURTAILMENT PLAN
(Continued)

ELIGIBILITY REQUIREMENTS: Bundled service, Community Choice Aggregation service, and direct access service customers are eligible to file an OBMC Plan provided the customer can demonstrate to PG&E's satisfaction the following items: (T)

1. The customer must be able to reduce its electric load such that the entire load on the PG&E circuit or dedicated substation that provides service to the customer is reduced to or below MLLs for the entire duration of each and every RO operation.

2. For the purpose of evaluating the ability of an OBMC plan to achieve a reduction in circuit load of fifteen (15) percent, the prior year average monthly peak circuit or dedicated substation demand, adjusted for major changes in facilities that resulted in permanent circuit load changes, will be used. Customers desiring adjustment to the prior year demands must submit a declaration signed and stamped by a California registered professional engineer attesting to the facility changes, providing detail of the source of kilowatt load changes, and the total permanent change in maximum demand. PG&E will, at the customer's expense, have the facility changes verified by an independent California registered professional engineer, unless otherwise waived by PG&E.

3. Customers must also be able to achieve a minimum of a 15% circuit load reduction from the established baseline upon notice to curtail. Customers submitting a declaration under Section 2 above for a reduction in prior year average monthly peak circuit or dedicated substation demand must be able to achieve a minimum of a 10% circuit load reduction from the established baseline upon notice to curtail.

4. Customers participating in an OBMC plan who are the only customers on their circuit may participate in a PG&E operated capacity interruptible program provided the program requires the reduction of load to a pre-established firm service level. Customers participating in a demand bidding program or the CPA DRP shall not be paid for load reduction during OBMC operations. Customers participating in an OBMC plan shall not participate in the CAISO's Demand Relief Program (DRP) or in a PG&E program that aggregates load for the CAISO's DRP.

5. The customer must sign the Agreement For Optional Binding Mandatory Curtailment Plan (Form No. 79-966) whereby the customer agrees to all terms and conditions set forth in this tariff and in said Agreement.

(Continued)

SCHEDULE E-OBMC—OPTIONAL BINDING MANDATORY CURTAILMENT PLAN
(Continued)

PLAN COMPONENTS:

Every OBMC Plan shall have the following components:

1. Name of lead customer including PG&E account number, electric rate schedule, service address, mailing address, and contact information including alphanumeric pager and facsimile numbers and e-mail address.

2. List of all non-lead customers including PG&E account number, service address, mailing address, and contact information.

3. The lead customer shall be the primary contact for the OBMC Plan. The customer shall furnish and maintain internet access, an e-mail address, alpha-numeric pager and facsimile machine as required for customer notification. The primary contact shall be responsible for contacting all non-lead customers.

4. As an attachment the OBMC Plan shall include any and all agreements that are made between the lead customer and the non-lead customers.

5. A financial plan that clearly demonstrates that any and all non-compliance penalties associated with the OBMC plan will be secured by the lead customer and/or the non-lead customers.

6. A load reduction plan that shall indicate the specific quantifiable measures to be utilized by the customer(s) to reduce load to or below each MLL. The load reduction plan must include the load reduction measures to be utilized during different time periods of the year to achieve the required load reductions when seasonal load profile changes occur. The customer is responsible for preparing and maintaining the load reduction plan.

7. Identification of the measuring equipment and means to verify that during the entire duration of the OBMC operation that the load on the circuit or dedicated substation has been reduced to or below the applicable MLL that corresponds the required percent load reduction. This measuring equipment is further specified below.

(Continued)

SCHEDULE E-OBMC—OPTIONAL BINDING MANDATORY CURTAILMENT PLAN
(Continued)

MEASURING EQUIPMENT: Where the OBMC customer is on a dedicated circuit or dedicated substation, compliance shall be determined from a telephone accessible electric revenue interval meter. Direct Access customers are required to allow PG&E telephone access to its electric revenue meter for the purposes of determining OBMC operation compliance. Where the existing meter is non-interval or is not compatible with PG&E's current telephone based meter reading systems, the customer is required to pay for the installation of an interval meter or other required equipment. For bundled service customers, Community Choice Aggregation service, or direct access customers who elect to have PG&E install the equipment, Electric Rule 2 shall apply. Where a meter is not currently being read via telephone, the customer shall coordinate and pay for the installation, and pay all ongoing costs of such necessary telephone equipment and service. The OBMC Plan shall not be approved by PG&E until such metering has been installed and the data is able to be collected via telephone or until PG&E is able to access the customer-owned meter. (T)

Where the OBMC customer is not on a dedicated circuit or if the OBMC Plan includes a group of customers, compliance for the circuit shall be determined from electronic recording equipment located in the PG&E substation. Where the circuit does not have electronic recording equipment to monitor its loads, the customer shall pay for the installation of the equipment as Special Facilities pursuant to Electric Rule 2. The OBMC Plan shall not be approved by PG&E until such electronic recording equipment has been installed and is operational.

PENALTIES: Failure to meet the load relief criteria established by an OBMC Plan shall result in a non-compliance penalty for the OBMC customers. The non-compliance penalty shall be equal to $6.00 per KWH times the average total load on the applicable circuit less the required MLL, as measured during each half-hour of the RO. Failure to pay these penalties may result in termination of electric service pursuant to Electric Rule 11.

PG&E will, without liability, terminate any OBMC Plan immediately for failure to reduce circuit load levels to within five (5) percent of the MLL for the entire duration of the RO for a second time during a twelve (12) month period. Such termination shall occur if the customer(s) bound by an OBMC Plan have not met or are unable to meet the load relief criteria specified therein. Customers terminated for non-compliance shall not be permitted to participate in an OBMC plan for a period of five (5) years from the date of termination.

Failure to maintain creditworthiness during the duration of the OBMC plan may result in immediate termination of the OBMC Plan.

TERM: An OBMC Agreement has an initial term of one (1) year but may be extended from year to year, after operational review, with the written approval of PG&E. The annual term shall commence upon the date effective start date specified in the PG&E approval letter.

Except as specified above, the customer or PG&E may terminate the OBMC Plan upon thirty (30) days written notice prior to the end of an annual term. If a customer terminates the OBMC Plan, the customer shall not be party to a subsequent OBMC Plan for a period of at least twelve (12) months.

Upon termination, regardless of the cause, the circuit will be assigned a Rotating Outage Block (ROB) and that the ROB may or may not be the same as when the OBMC Plan was initiated.

Pacific Gas and Electric Company®

Optional Binding Mandatory Curtailment Plan

Under the Optional Binding Mandatory Curtailment (E-OBMC) Plan you can be exempted from rotating outages if you agree to reduce the load on the entire electric circuit that serves your facility. If you share an electric circuit with other Pacific Gas and Electric Company customers and you are the E-OBMC lead customer, you will need to work with the affected customers to ensure that the load reductions for the entire circuit meet the program requirements.

How It Works

To participate in the E-OBMC program, you must file an E-OBMC load reduction plan with Pacific Gas and Electric Company for approval. The plan must show how you will reduce up to 15 percent of your circuit load below the prior year's average monthly peak circuit demand, adjusted for any major changes in loads on the circuit. Bundled service and direct access service customers are eligible for this program.

Load reductions required under an E-OBMC plan will be issued for whenever the California Independent System Operator (CAISO) calls for rotating outages in Pacific Gas and Electric Company's service territory. We will notify you with the required percent load reductions, from 5 percent increments to 15 percent, along with the start and end times for E-OBMC operation. You must implement the reduction within 15 minutes of notification.

The circuit baseline used to determine if you have met the load reduction requirement is based on the average hourly electric usage on your circuit during the previous 10 similar days, excluding days when an E-OBMC plan curtailment occurred. There is no limit on the frequency or duration of the plan curtailments.

There are no financial incentives for participating in the E-OBMC program; your benefit is the exemption from rotating outages. You are responsible for all costs necessary to participate in the E-OBMC program. And there are penalties associated with non-compliance to E-OBMC plan curtailments.

Equipment Requirements

If you are the only customer on your circuit, standard interval metering may be sufficient to participate in the program. For multi-customer circuits, substation-level metering will be required. In either event, program participants will pay the cost of required metering equipment. Pacific Gas and Electric Company will facilitate communications between customers on a shared electric circuit for the purposes of participating in this program.

For more information about how your business can benefit from InterAct II and our demand response programs, contact your local PG&E Account Representative or call 1 (800) 468-4743.

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Schedule OBMC Sheet 1

OPTIONAL BINDING MANDATORY CURTAILMENT

APPLICABILITY

This Schedule is optional for customers who can curtail load on the customer's entire circuit, either on its own or through joint participation with other customer's receiving service on the same circuit, by the required amount as defined in Special Condition 3, for the entire duration of every rotating outage. Additionally, customer must submit an acceptable Optional Binding Mandatory Curtailment plan with SCE, as defined in Special Condition 2, prior to participation in this program. This Schedule exempts participating customers from rotating outages in exchange for partial load curtailment during every rotating outage period. (D)

TERRITORY

Within the entire territory served.

RATES

All charges and provisions of the customers' otherwise applicable Schedule shall apply.

SPECIAL CONDITIONS

1. Optional Binding Mandatory Curtailment Event. An Optional Binding Mandatory Curtailment (OBMC) event will occur when the Independent System Operator (ISO) declares a rotating outage within SCE's service area. When an OBMC event is called, SCE will determine if the customer complied with such event by using the baseline measurement method in accordance with Special Condition 5.b.

2. OBMC Plan: A participating customer shall, either solely or jointly with one or more customers on the same circuit, submit an OBMC plan detailing how load curtailment on the entire circuit can be achieved by the plan participants in 5 percent increments to a total load curtailment of 15 percent. The customer is defined as the party(s) that signs and submits the OBMC plan. The plan must also indicate how compliance of the load curtailment can be monitored and enforced. The burden is on the customer(s) to demonstrate that the OBMC plan is realistic, workable, measurable, and enforceable. When any one customer expresses its intent to participate in an OBMC plan, SCE will facilitate an OBMC plan by notifying customers on the circuit and coordinating communication between customers. An OBMC customer with a single tax payer identification number may aggregate the load of two circuits for the purposes of participating in the OBMC program provided: (a) it is the lead customer for both circuits; (b) it has the ability to achieve required load reductions on the total load for the circuits; (c) it agrees to achieve required load reductions on individual circuits subject to the aggregation as required by SCE or the ISO in response to geographic area constraints; and (d) the customer commits in Form 14-740 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.

3. Required Amount of Circuit Load Curtailment: Participating customers must have the ability to curtail load on the entire affected circuit(s) by 15 percent.

4. Load Curtailment Increments: Load curtailment will be requested in increments of 5 percent, up to a maximum of 15 percent during an OBMC event.

(Continued)

Schedule OBMC — Sheet 2

OPTIONAL BINDING MANDATORY CURTAILMENT

(Continued)

SPECIAL CONDITIONS (Continued)

5. Baseline Measurement for Determination of Required Load Curtailment: Two baseline measurements will be used to determine 1) if the required 15 percent curtailment can be obtained, and 2) if the 10 percent load curtailment has been met.

   a. Baseline Measurement for Determination of Obtainable 15 percent Curtailment. The potential of curtaining at least 15 percent load on a given circuit will be measured by using the prior year's same month, average peak period load, adjusted for major changes in facilities.

   b. Baseline Measurement for Determination if 10 Percent Curtailment. At least 10 percent of the total load curtailment must be achieved during each 30 minute period during an OBMC event. This will be determined by measuring the circuit load during an OBMC event, in 30 minute periods, against the same 30 minute periods of the past 10 similar days. If the OBMC event occurred on a business day then the past 10 similar days will include business days only. If the OBMC event occurred on a weekend or holiday day then the past 10 similar days will include weekend or holiday days only. The past 10 similar days will exclude days when the customer was paid to curtail load (e.g., participation in the Demand Bidding Program or when the OBMC program operated).

   c. An OBMC participant may exclude the following periods from the past 10 similar days used to determine Baseline:

      i. Ramp-Up and Ramp-Down of Operations. Customer shall have a period of 15 consecutive 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 day prior to an OBMC event. Customers requesting an operation ramp-up period must also 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 percent from the 10-day baseline immediately prior to the ramp-down period. Customers failing to achieve a 25 percent 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. The customer shall provide at least 10 calendar days prior notice to SCE when exercising this option.

      ii. Varying Conditions in Operations. Customer shall have up to 10 days per calendar year as determined by the customer and designated in advance to accommodate conditions in the customer's operations that affect the 10-day baseline. The customer shall provide at least seven calendar days' prior notice when exercising this option.

      iii. Unplanned Outages. Customer shall have up to two exclusions from the 10-day baseline where unplanned outages or other events cause the circuit load to deviate substantially from normal conditions. The customer shall provide notice within one calendar day after the outage or event when exercising this option.

   Customer requests for the above options must be received by SCE in written or e-mail format within the specified time frames or the requested option will not be allowed.

(Continued)

Schedule OBMC Sheet 3

OPTIONAL BINDING MANDATORY CURTAILMENT

(Continued)

SPECIAL CONDITIONS (Continued)

6. Participation in Other Programs: OBMC participants who are the only customers on their circuit may participate in an SCE administered capacity interruptible program as long as that program requires the reduction of load to a pre-established firm service level (FSL). OBMC participants are eligible to concurrently participate in the Demand Bidding Program (DBP) or the California Power Authority Demand Reserves Partnership Program CPA DRP, but shall not be paid for any load curtailment during periods when an OBMC event overlaps a DBP or CPA DRP Event.

7. Charges for Excess Energy: For each OBMC event during which the customer fails to curtail load to its required level, as measured in 30 minute periods, and hence incurs Excess Energy, the applicable $/kWh penalty in accordance with Special Condition 9 shall be added to the customer's billing as otherwise provided in this Schedule.

8. Excess Energy: The number of kWh consumed in each 30 minute period in an OBMC event that exceeds the required circuit load curtailment, as measured for each 30 minute period of an OBMC event shall be considered Excess Energy. Excess Energy shall be measured using the baseline measurement in accordance with Special Condition 5.b.

9. Excess Energy Charges: Penalties equal to $6/kWh shall apply to all excess energy, for each OBMC event.

10. Cost of Equipment: Communication, metering, or any other equipment required to participate in this program is the sole responsibility of the customer(s).

11. Failure to Comply: Failure to curtail circuit load to within 5 percent of the required amount, as measured during the entire duration of an OBMC event, on two occasions in any one year shall result in the customer(s) termination on the program and the customer shall be prohibited from participating in an OBMC program for five years.

12. Agreements. All applicable agreements, including an Optional Binding Mandatory Curtailment Agreement Between Customer and Southern California Edison Company (SCE), Form 14-740, must be signed in order to receive service under this Schedule.

(D)

THE OPTIONAL BINDING MANDATORY CURTAILMENT PROGRAM (OBMC)

The Optional Binding Mandatory Curtailment Program (OBMC) exempts customers from rotating outages in exchange for partial power reductions from their entire circuit over a longer period. Specifically, customers must reduce power on their entire circuit by up to 15% during the entire duration of every rotating outage event. To participate in the OBMC Program, customers must submit a signed OBMC Plan acceptable to Southern California Edison (SCE).

Who May Benefit from the OBMC Program?

Any customer (or group of customers) with the ability to reduce up to 15% of power from a participating circuit, in increments of 5%, during every rotating outage, may participate in the OBMC Program. In general, those that may benefit from this program are large commercial or industrial customers who can turn off a significant portion of their lighting and/or air conditioning use for extended periods, or can shut down ancillary or non-essential portions of their manufacturing process. These customers must be able to reduce the required amount of power on their circuit themselves, or coordinate power reductions with other customers who share their circuit.

Note: Customers taking service at the sub-transmission level (66kV and above) are considered as a single-circuit customer.

How Can We Participate?

- Submit an acceptable Optional Binding Mandatory Curtailment Plan, and sign the OBMC Agreement (Form 14-740). Appendix A to the OBMC Agreement must demonstrate how a 15% power reduction on the entire circuit can be achieved, and how program requirements can be monitored and enforced.
- Reduce power on the circuit by up to 15%, in increments of 5%, during every rotating outage when directed to do so by SCE.

  — or, if sharing a circuit, coordinate with others on the circuit to achieve the requested power reduction.
- Pay for and install communication, metering, or any other equipment required to participate in this program.

What Are SCE's Responsibilities?

- To provide OBMC Program materials and information.
- To coordinate communications and meetings for customers on the same circuit when any one customer expresses interest in taking a lead role to aggregate electrical usage.
- To identify OBMC Plan deficiencies and recommend appropriate solutions for single-party and multiple-party circuit users considering the OBMC Program.
- To review customer-submitted OBMC Plans and, upon approval, exempt the

participating customers' circuit from rotating outages after all program requirements are complete and the circuit is determined to be operationally ready for participation in the program.

What Happens If We Do Not Reduce Power From Our Circuit?

Failure to reduce the agreed-upon amount of power from the circuit results in a penalty of $6 per kWh of excess energy. If OBMC Plan participants fail to reduce the required amount of power under the terms of the OBMC Agreement during two events in any one-year, the lead customer will be terminated from the program, and will not be permitted to rejoin the OBMC Program for five years.

OTHER SCE LOAD REDUCTION PROGRAMS

OBMC customers may participate in other SCE power reduction programs. Specifically, OBMC customers may participate in the Base Interruptible Program (I-6-BIP) or the Large Power Interruptible Program (I-6), subject to certain restrictions. OBMC customers may also participate in the Demand Bidding Program (DBP), but will not be paid under that program for any DBP power reduction events that overlap with OBMC events.

OBMC/I-6 JOINT PARTICIPATION CHANGES

OBMC customers who participate in the I-6 program will be able to reduce load from the 10-day baseline, rather than using the lower of their FSL or 10-day baseline, once their monthly and annual obligations have been fulfilled under I-6. However, if an OBMC and I-6 event are simultaneously in effect, then the lower of the customer's FSL or 10-day baseline shall continue to apply until the OBMC event is terminated, unless the participating OBMC customer has met its monthly or annual obligations prior to the start of an OBMC event.

FOR MORE INFORMATION

SCE has several programs available to help customers better manage their electricity costs, such as rebates, incentives, energy surveys and payment options.

If you have questions about other SCE programs or the OBMC Program, call (800) 990-7788, contact your SCE representative, or visit www.sce.com.

This fact sheet is meant as an aid to understanding SCE's pricing schedules. It does not replace the tariffs. Please refer to the individual rate schedule of interest for a complete listing of terms and conditions of service, which can be viewed or printed via the Internet at www.sce.com (Regulatory Info Center).

EDISON

SCHEDULE OBMC

OPTIONAL BINDING MANDATORY CURTAILMENT PLAN

APPLICABILITY

This Schedule is applicable, in combination with a customer's otherwise applicable tariff(s), on a voluntary basis, to customers who are able to reduce their entire circuit load by at least 15% and meet eligibility requirements in Special Condition #2.

TERRITORY

Within the entire territory served by the utility.

RATES

Non Compliance Penalty: The average total load on the applicable circuit less the required Maximum Load Level (MLL), times $6.00/kWh, as measured during each half-hour of the Rotating Outage (RO). T T

SPECIAL CONDITIONS

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

2. Eligibility Requirements:

   A customer is eligible to file an OBMC Plan provided the customer can demonstrate to SDG&E's satisfaction all of the following items:

   a. The customer must be able to reduce its electric load such that the entire load on the SDG&E circuit, that provides service to the customer, is reduced to or below the required MLLs for the entire duration of each and every RO operation. The MLLs are defined below.

   b. The customer must be able to reduce circuit load by 15%. The baseline used to determine if this 15% reduction can be met is the "Previous Year Baseline" as described in Special Condition 4.

   c. The customer must also be able to reduce circuit load by 10%, based on the "10 Day Baseline" described in Special Condition 4. However, if the customer can reduce circuit load by 15% based on the "10 Day Baseline," that customer is not subject to the eligibility requirement in 2.b. above.

   d. The customer must sign the Optional Binding Mandatory Curtailment Plan Contract (142-05205) whereby the customer agrees to all terms and conditions set forth in this tariff and in said Contract.

(Continued)

SCHEDULE OBMC

OPTIONAL BINDING MANDATORY CURTAILMENT PLAN

SPECIAL CONDITIONS (Continued)

2. Eligibility Requirements (Continued)

e. Customers participating in an OBMC Plan who are not on a dedicated circuit shall not participate in a capacity interruptible program.

f. Customers participating in an OBMC Plan who are on a dedicated circuit may also participate in acceptable capacity interruptible programs, which are limited to Schedules BIP and AL-TOU-CP. When a participant in a capacity interruptible program has completed its monthly or annual obligations under that program, the load reduction requirement reverts to the otherwise required OBMC load reduction, except that if an OBMC event is simultaneously in effect at the time that the capacity interruptible program obligations (monthly or annual) are met, then the requirements in Special Condition 5 still apply.

g. Customers participating in an OBMC Plan may also participate in the California Power Authority's Demand Reserves Partnership (CPA-DRP). N N

h. Customers participating in an OBMC Plan shall not participate in the ISO's DRP or on Schedule MPL, which aggregates load for the ISO's DRP. T

i. Customers participating in the Demand Bidding Program (DBP) shall not be paid for load reduction during OBMC operations. T

3. Notice of Operation: SDG&E shall require a customer to reduce load by the required amount upon each and every notice from the California Independent System Operator (CAISO) that a firm load curtailment is required within the SDG&E service territory, and maintain the load reduction for the full duration of each outage. Additionally, SDG&E reserves the right to require a customer to reduce load when SDG&E or the CAISO has initiated or is planning to initiate firm load curtailments in a local geographic area within the SDG&E service territory.

4. Previous Year Baseline: For the purpose of evaluating the ability of an OBMC Plan to achieve a reduction in circuit load of 15%, the baseline used to calculate eligibility requirement in Special Condition 2.b. is the prior year's, same month, average peak period usage, adjusted for major changes in facilities that resulted in permanent circuit load changes. Customers desiring adjustment to the prior year demands must submit an affidavit signed and stamped by a California registered professional engineer attesting to the facility changes, providing detail of the source of kilowatt load changes, and the total permanent change in maximum demand. SDG&E will, at the customer's expense, have the facility changes verified by an independent California registered professional engineer, unless otherwise waived by SDG&E. Customers submitting an affidavit under this section for a reduction from the Previous Year Baseline demands must be able to achieve a minimum of a 10% circuit load reduction from the "10 Day Baseline" described in Special Condition 5 upon notice to curtail.

5. 10 Day Baseline: For the purpose of determining if the required load reduction on the circuit has been obtained, the baseline is equal to the average recorded hourly usage amount (if available) for the same hours as the OBMC operation hours on the immediate past 10 similar days, excluding 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. If a customer participates in both an acceptable capacity interruptible program and the OBMC program, the required OBMC reduction

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(Continued)

SCHEDULE OBMC

OPTIONAL BINDING MANDATORY CURTAILMENT PLAN

SPECIAL CONDITIONS (Continued)

5. 10 Day Baseline: (Continued)

shall be applied to the lower of the 10-day baseline or the customer's Firm Service Level unless the monthly or annual obligation for the capacity interruptible program has been fulfilled in prior events. For customers on Schedule AL-TOU-CP, Firm Service Level is equal to the Contract Minimum Demand. The load measurements for the circuit shall be taken at SDG&E's distribution substation. L | | L

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 SDG&E when exercising option (a); a minimum of 7 calendar days prior notice to SDG&E when exercising option (b); and notice to SDG&E within one calendar day after the outage or event when exercising option (c). Customer requests for the above exclusions must be received by SDG&E in written or e-mail 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 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 by 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.

6. Maximum Load Level (MLL): Maximum Load Level (MLL) is established by SDG&E corresponding to each of the 5, 10, and 15% load reduction level on the applicable circuit. The MLL for the 5% load reduction level is equal to the product of the 10 Day Baseline times .95. The MLL for the 10% load reduction level is equal to the product of the 10 Day Baseline times .90. The MLL for the 15% load reduction level is equal to the product of the 10 Day Baseline times .85. The percentage load reduction will be determined by SDG&E based on the MW load reduction called for by the CAISO divided by SDG&E average peak load. The CAISO may call for load reductions on a required MW level, but SDG&E will require the OBMC customers to reduce their load to the next highest 5% increment. For each operation, SDG&E will notify the customer of the required percent reduction, along with the start and end times for the OBMC operation. SDG&E may extend the end time or increase the percentage reduction of any ongoing OBMC operation as necessary to correspond with CAISO directives.

7. Response Time: Required load reductions must be achieved as quickly as possible but no later than 15 minutes after the primary customer receives notification from SDG&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.

8. Non-Exclusion from Rotating Outages: An OBMC Plan is applicable to only electrical emergencies requiring a RO as a part of SDG&E's load curtailment block progression plan and is not a guarantee against a customer being subject to a RO due to other emergencies. The customer may not receive advance notice from SDG&E of such a RO.

(Continued)

SCHEDULE OBMC

OPTIONAL BINDING MANDATORY CURTAILMENT PLAN

SPECIAL CONDITIONS (Continued)

9. Customer Aggregation: SDG&E will facilitate joint curtailment plans by notifying customers of the program and coordinating communication between customers on the circuit when any one customer expresses its intent to participate. All customers involved in a particular OBMC Plan must be served from the same circuit unless expressly agreed to by SDG&E. SDG&E would consider an OBMC Plan which involves the aggregation of two circuits as follows: an OBMC customer with a single taxpayer identification number may aggregate the load of two circuits for the purposes of participating in the OBMC Plan 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 SDG&E or the CAISO in response 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 Plan. All provisions of this Schedule applicable to individual OBMC Plans shall apply to the aggregated OBMC Plan.

   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, the group shall choose a single customer to 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.

10. Annual Update Requirement: Customers are required to update their OBMC Plans by March 15 of each year, and confirm with SDG&E any changes to the previous year's version. As part of this review, SDG&E shall update the MLL to reflect the circuit loading since the prior summer. An OBMC Plan may 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. T

11. Components Of An Optional Binding Mandatory Curtailment Plan: Every OBMC Plan shall have the following components:

    a. Name of lead customer including SDG&E account number, electric rate schedule, service address, mailing address, and contact information including pager and facsimile numbers

    b. List of all non-lead customers including SDG&E account number, service address, mailing address, and contact information.

    c. The lead customer shall be the primary contact for the OBMC Plan. The lead customer shall furnish and maintain an alpha-numeric pager and facsimile machine that will be used for lead customer notification. The primary contact shall be responsible for contacting all non-lead customers.

    d. The "10 Day Baseline" must be established for the SDG&E circuit that provides service to the customer(s). The load measurements for the circuit shall be taken at SDG&E's distribution substation.

(Continued)

SCHEDULE OBMC

OPTIONAL BINDING MANDATORY CURTAILMENT PLAN

SPECIAL CONDITIONS (Continued)

11. Components Of An Optional Binding Mandatory Curtailment Plan: (Continued)

    e. MLLs shall be established for the circuit which correspond to each of the 5, 10, and 15% load reduction level from the "10 Day Baseline. L

    f. A load reduction plan that shall indicate the specific quantifiable measures to be utilized by the customer(s) to reduce load to or below each MLL. The load reduction plan must include the load reduction measures to be utilized during different time periods of the year to achieve the required load reductions when seasonal load profile changes occur. The customer is responsible for preparing and maintaining the load reduction plan.

    g. Identification of the measuring equipment and means to verify that during the entire duration of the OBMC operation that the load on the circuit or dedicated substation has been reduced to or below the applicable MLL that corresponds to the required percent load reduction. This measuring equipment is further specified in Special Condition 12 below. L

12. Measuring Equipment To Verify Compliance: Where the OBMC customer is on a dedicated circuit, compliance shall be determined from a telephone-accessible electric revenue interval meter. Direct Access customers are required to allow SDG&E telephone access to its electric revenue meter for the purposes of determining OBMC operation compliance. Where the existing meter is non-interval or is not compatible with SDG&E's current telephone-based meter reading systems, the customer is required to pay for the installation of an interval meter as Special Facilities pursuant to Electric Rule 2. Where a meter is not currently being read via telephone, the customer shall coordinate and pay for the installation, and pay all ongoing costs of such necessary telephone equipment and service. The OBMC Plan shall not be approved by SDG&E until such metering has been installed and the data is able to be collected via telephone or until SDG&E is able to access the customer-owned meter. Where the OBMC customer is not on a dedicated circuit or if the OBMC Plan includes a group of customers, compliance for the circuit shall be determined from electronic recording equipment located in the SDG&E substation. Where the circuit does not have electronic recording equipment to monitor its loads, the customer shall pay for the installation of the equipment as Special Facilities pursuant to Electric Rule 2. The OBMC Plan shall not be approved by SDG&E until such electronic recording equipment has been installed and is operational.

13. Failure To Comply And Non-Compliance Penalties: Failure to meet the load relief criteria established by an OBMC Plan shall result in a non-compliance penalty for the OBMC customer. The non-compliance penalty shall be equal to the average total load on the applicable circuit less the required MLL, times $6.00/kWh, as measured during each half-hour of the RO. Failure to pay these penalties may result in termination of electric service pursuant to Electric Rule 11. If participant fails to reduce circuit load to within 5% of the required amount of the entire duration of the RO on two occasions in any one year, SDG&E shall, without liability, terminate OBMC participation immediately and the customer shall be prohibited from participating in an OBMC program for 5 years. Such termination shall occur if SDG&E determines that the terms and conditions of the OBMC Plan have not been met. T T

L

(Continued)

SCHEDULE OBMC

OPTIONAL BINDING MANDATORY CURTAILMENT PLAN

SPECIAL CONDITIONS (Continued)

14. Term Of Agreement: An OBMC Contract has an initial term of one (1) year but may be extended from year to year, after operational review, with the written approval of SDG&E, according to Special Condition 9. The annual term shall commence upon the effective start date specified in the SDG&E approval letter.

15. Termination of Agreement: Except as specified in Special Condition 13 above, the customer or SDG&E may terminate the OBMC Plan upon thirty (30) days written notice prior to the end of an annual term. If a customer terminates the OBMC Plan, the customer shall not be party to a subsequent OBMC Plan for a period of at least twelve (12) months. Upon termination, regardless of the cause, the circuit will be assigned a Rotating Outage Block (ROB) and the ROB may or may not be the same as when the OBMC Plan was initiated.

16. Emergency Standby Generation Limitations: Not withstanding all other applicable SDG&E Rules and Tariffs, Customer may synchronize and operate its own standby generation in parallel with the electric system for up to 60 cycles to minimize service interruption during the transfer of electric service between the Utility electric system and the Customer's Emergency Standby Generation. Such operation shall only occur during the period starting 15 minutes prior to and ending 15 minutes after a curtailment event defined in this Tariff. Customer must review their interconnection plans with SDG&E prior to operation of their generator in parallel with SDG&E's system. In no event shall the customer operate its own standby generation in parallel with the Utility electric system during Utility service interruptions.

    Upon termination or expiration of the term of this Tariff or Contract, customer agrees to either (1) dismantle all equipment necessary for customer's own standby generation to synchronize and operate in parallel with the Utility electric system for the purpose of electric service transfer from the Utility electric system to the customer's own standby generation, or (2) purchase and install a generator output meter meeting SDG&E's standards and either comply with applicable tariffs or take service under a contract.

17. Termination of Schedule: This Schedule is in effect until modified or terminated in the rate design phase of SDG&E's next general rate case or similar proceeding. N
N

Incentives for Customized Energy-saving Projects

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Customer Choice
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Economic Development
Safety
Energy Links
Renewable Energy
Events & Training

Optional Binding Mandatory Curtailment

The Optional Binding Mandatory Curtailment (OBMC) provides you exemption from rotating outages if you agree to reduce the electric load on the entire electric circuit that serves your facility by as much as 15%. If you share an electric circuit with other SDG&E customers and wish to participate in OBMC you will be required to coordinate with the other customers on the circuit to ensure that the load reductions for the entire circuit meet the program requirements.

How OBMC works

OBMC participants will be required to reduce load every time a rolling blackout or rotating outage occurs. If your business is the only business on your circuit, you alone are responsible for achieving the required load reduction level. If you share a circuit with other businesses, SDG&E can assist with coordinating load reduction as a joint effort of customers on the same circuit to achieve the required electricity load reduction. If you are on a circuit requiring aggregate load reduction, one business will be designated as the primary participant, and will be responsible for developing the plan for how load will be curtailed to achieve the required load reduction.

OBMC will be triggered if rolling blackouts or rotating outages become necessary. SDG&E will initiate the curtailment signal at the direction of the California Independent System Operator. Participants will be notified through alphanumeric paging, dedicated phone line, and/or kWickview, and will have 15 minutes from when the primary program participant receives notification to reduce load.

There is a $6/kWh penalty for energy consumed above the power reduction commitment.

Eligibility

Businesses that can commit to reducing as much as 15% of their circuit are eligible. Reduction when requested is mandatory. Businesses with production lines sensitive to power disruptions, those dealing in perishable commodities, or those with labor intensive processes that face overtime costs may benefit most from the OBMC program.

Additional Benefits

SDG&E's Technical Assistance and Technology Incentive Program also provides assistance in determining your demand response potential and incentives for equipment that enhances your ability to respond to requests for on-peak demand reductions.
OBMC participants may be eligible to participate in other demand response programs, but restrictions do apply, and participants cannot receive incentives from more than one program for the same load reduction.

For more details on Optional Binding Mandatory Curtailment, contact your SDG&E Account Executive, call 866-377-4735 or

Related Information

kWickview
Default CPP Rates
Contact DRP
Demand Response Overview Brochure
Energy Management Pyramid
Demand Response FAQs

email drp@semprautilities.com

Click here for a copy of the OBMC contract.

Click here to view the OBMC tariff.

This program is available throughout California and is offered by the state's investor owned utilities.

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A7. Technical Assistance/Technical Incentive Program Materials

Technical Assistance Program

PG&E offers you engineering assistance to help you determine how, and by how much, you may be able to reduce demand under a PG&E's demand response or reliability program.

How It Works

PG&E will provide a high-level evaluation of your facility and end uses that includes your demand response potential – identifying ways that load might be shifted or demand temporarily reduced without adversely affecting your business.

If it appears that you will benefit, PG&E will provide an in-depth Integrated Energy Audit conducted by an engineer who will identify and rank opportunities that can help you save energy, reduce and shift demand, and lower your energy bills.

Incentives

PG&E will provide the audit at no cost or will pay you up to $50 per kilowatt of identified demand response capability for a third-party audit, provided that consultant you choose is a Professional Engineer licensed in the Stat of California.

Additional Information

Through the audit report you will learn what options you have with your current systems for both manual and automatic demand response, as well as what equipment replacements and/or enhancements would increase your demand response capabilities. The report will also analyze the financial benefits of each recommendation and explain the synergies between the demand response, energy efficiency, and other opportunities identified.

PG&E offers a total of six demand response and reliability programs. Our experts will look at all of your options for reducing demand and will recommend those best suited to your facility.

For more information about how your business can benefit from our demand response programs, contact your local PG&E Account Representative or call Business Customer Service Center at
(800) 468-4743.

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Pacific Gas and Electric Company®

Technical Incentive Program

PG&E offers cash incentive payments for the installation of equipment or control software that provides demand response. The combined program is open to Projects involving qualifying commercial, industrial and agricultural customers. This program is limited to medium and large customers.

How It Works

The Customer is the utility customer whose site or sites is implementing the demand response measure(s). All commercial, industrial and agricultural customers who: 1) receive retail electric service from PG&E, 2) has had a maximum demand greater than or equal to 200 kW within the last 12 billing months, and 3) must have an existing electric meter that is capable of recording usage in 15 minute intervals and that can be read remotely by PG&E are eligible for Program participation as a customer.

Incentives

Investments in hardware and software that enable you to participate in demand response programs qualify for incentive payments. You can also apply for rebate totaling $100 per kilowatt of verified load reduction capability associated with the installation of recommended enabling technologies. The duration of the load reduction demonstration depends on the load being curtailed. Most demonstrations will be less than 1 hour.

Additional Information

Examples of enabling technologies for which you can receive rebates include smart thermostats, energy management systems, remote switches, dual-level lighting, and software upgrades, as well as added control points. Projects that increase the demand response capability of existing energy management or information systems (EMS or EIS), or enable you to modify your business processes (such as investments in process or operating equipment), may also qualify.

Of course, you can be “demand responsive” by manually flipping switches, but automating the task makes it much easier, and after receiving the incentives, the automation technology may pay for itself.

Upgrading your control systems has other advantages as well. First, PG&E’s demand response programs have their own incentive structures, which reward you for participation. Second, the same equipment can be used for multiple purposes. And third, automated control systems are easier to link to information systems through which you can monitor, analyze, and plan your energy usage and manage your energy budget.

Energy efficiency and demand reduction can work hand-in-hand to help you lower you energy bills. The technical assistance study can answer your questions about demand response and show how a demand response capability can also be used to help meet your energy efficiency goals.

For more information about how your business can benefit from our demand response programs, contact your local PG&E Account Representative or call Business Customer Service Center at
(800) 468-4743.

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Technical Assistance and Technology Incentives

Fact Sheet

OVERVIEW

Southern California Edison's (SCE) Technical Assistance and Technology Incentives program provides eligible commercial and industrial customers technical assistance in the form of demand response site assessments at no charge, and financial incentives for the installation of eligible technologies that reduce electricity usage during periods of peak demand. These services are also intended to give you increased flexibility to participate in other demand response programs that provide additional energy-saving incentives.

Eligibility

All customers in SCE's service territory with interval meters and registered demands of 200 kW or more are eligible to take advantage of this program. Participants include large office complexes, retail stores, large manufacturing firms, warehouses, process industrial facilities, water agencies, and agricultural and institutional facilities.

THE TECHNICAL ASSISTANCE PROCESS

The Preliminary Assessment

The technical assistance process begins when you contact your SCE account representative to discuss your business' demand response potential and schedule a preliminary assessment. You will need to complete registration forms that will help SCE staff schedule technical assistance and reserve funds for technology incentives. The preliminary assessment will be performed by an engineer contracted by SCE. The engineer who performs the preliminary assessment will then determine whether a more in-depth technical audit of projected load reduction potential in your facility is recommended.

There are no charges associated with a preliminary assessment conducted by an SCE-contracted engineer.

You have the option of using an engineer of your choosing to conduct a preliminary assessment. However, any costs incurred for the preliminary assessment will not be covered by the program, and must be covered by you.

The Technical Audit

A technical audit will identify applicable demand response practices and methods, and recommend measures and technologies to achieve demand response potential. If SCE determines that a technical audit of your facility is warranted based upon a preliminary assessment, the technical audit will be conducted by an SCE-contracted engineer.

You have the option of using an engineer of your choosing to conduct a technical audit. Your selected engineer's qualifications must be acceptable to SCE, and the technical audit must be comparable to a technical audit performed by an SCE-contracted engineer and contain reasonable findings and recommendations. If you use an engineer of your choosing to conduct a technical audit, any costs for the technical audit must be covered by you. You may seek reimbursement from the Program of up to $50/kW of load reduction identified through the technical audit, not to exceed the actual reasonable cost of the audit, provided the technical audit is accepted by SCE.

HOW TO APPLY FOR TECHNOLOGY INCENTIVES

Technology incentives are available to eligible customers for the installation of qualifying demand response technologies.

Qualifying technologies include, but are not necessarily limited to, energy management systems, dual-level lighting, remote-controlled switches, building automation systems, demand control software, and/or other enhanced automation technologies.

To Reserve Technology Incentives

You may reserve technology incentives prior to proceeding with the installation of qualifying technologies. To reserve incentive funds, request and fill out a Technology Incentive Reservation Request. Once confirmed by SCE, the reservation will be in effect for 180 calendar days.

To Apply for Technology Incentives

Once you've purchased and installed one or more qualifying demand response technologies in your facility, you can apply to receive technology incentives from the Program. Complete and provide SCE with an Application for Technology Incentive. Upon availability of funding and measurement and verification by SCE of your facility's dispatchable load reduction potential enabled by the installed qualifying technology, you will be reimbursed up to $100 per kW of measured and verified load reduction, not to exceed the actual reasonable cost of the purchase and installation of the qualifying technology. Technology incentives are available on a first-come, first-served basis until funding is depleted or the program is terminated, whichever comes first.

TA&TI AND DEMAND RESPONSE PROGRAM PARTICIPATION

To be eligible to receive 100% of the technology incentive for your installed qualifying technology, you must enroll your facility in and participate in one or more qualifying demand response programs for at least 12 consecutive months. Otherwise, you can only be eligible to receive 50% of the technology incentive for your installed qualifying technology.

Qualifying demand response programs include the Demand Bidding Program, the Time-of-Use Base Interruptible Program, the Agricultural Pumping-Interruptible Program, several of the Critical Peak Pricing programs, the California Demand Reserves Partnership, the Large Interruptible Program, and the Optional Binding Mandatory Curtailment Program.

NOTE: *Customers who participate in multiple demand response programs cannot receive multiple program payments for the same reduced load.*

FOR MORE INFORMATION

To learn more about Technical Assistance and Technology Incentives, send an email to **ta&ti@sce.com**, or call the TA&TI Hotline at **(626) 302-1169**. To learn more about other SCE demand response or energy efficiency programs, please contact your account representative. You can also give us a call at **(800) 990-7788**, or visit us online at **www.sce.com**, **www.sce.com/drp**, or **www.sce.com/rebatesandsavings**.

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California Demand Reserves Partnership (Cal-DRP)
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Summer Discount Plan
Standard Performance Contracts (SPC)
Pumping Services
Industrial
Commercial
Agricultural
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Self Generation Incentive Program (SGIP)
Assistance For Low-Income
Energy Centers
Design & Engineering Services
EE Partnerships
Customer Generation

Expand All | Collapse All

Technical Assistance and Technology Incentives

Start With TA&TI and Start Receiving Demand Response Benefits

Southern California Edison's (SCE) Technical Assistance and Technology Incentives (TA&TI) can help start you on your way to receiving the benefits of SCE's demand response programs.

The TA&TI program provides technical assistance in the form of demand response site assessments, usually at no charge, to eligible commercial and industrial customers. The program also offers incentives for implementing measures and installing technologies that reduce electricity use during periods of high demand.

How to Receive Technical Assistance and Technology Incentives

Schedule a Preliminary Assessment
If you have an annual demand of 200 kilowatts (kW) or more and own a meter that records energy use at 15-minute intervals, you are encouraged to contact your SCE account representative to discuss your organization's general demand response potential, and to complete an informational form that will help SCE schedule your business' preliminary assessment. You must be able to demonstrate the ability to reduce electric load in order to receive demand response incentives.

Schedule a Technical Audit
If your business qualifies for a technical audit, SCE will schedule a detailed on-site assessment of projected demand reduction potential. This will be performed by an engineering firm that SCE selects, or an independent engineer of your choice who is pre-approved by SCE. Both the preliminary assessment and the technical audit are provided by SCE to you at generally no cost. If you choose an independent engineering firm for the audit, SCE will reimburse your business for all or some of the cost. If SCE selects both the preliminary assessment and the technical audit engineer(s), there is usually no cost to you.

Apply for Incentives
Based on the results of the audit, you can apply for technology incentives to help pay for the installation of demand reduction equipment. Qualifying equipment can include dual-level lighting, remote-controlled switches, demand control software, and/or enhanced automation systems.

Sign Up for Demand Response Programs and Receive More Benefits To be eligible to receive 100% of the technology incentive for your installed qualifying technology, you must enroll your facility in and participate in one or more qualifying demand response programs for at least 12 consecutive months. Otherwise, you can only be eligible to receive 50% of the technology incentive for your installed qualifying technology. For descriptions of these and other demand response programs, please visit **sce.com/drp.**

TA&TI program incentives are offered by all California investor-owned utilities to their own customers.

Where to Find More Information

For more information about SCE's TA&TI program, contact your SCE account representative, call the Technical Assistance and Technology Incentives Hotline at (626) 302-1169, or send an email to ta&ti@sce.com. For more information about other SCE demand response programs, visit **www.sce.com/drp**. You can find more information at the links below:

Technical Assistance and Technology Incentives Fact Sheet

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Technical Assistance and Technology Incentives

The Technical Assistance and Technology Incentives programs give customers the ability to participate in Demand Response Programs and receive incentives for demand response technologies.

SDG&E will provide business customers site assessments at no charge to determine demand response potential. Technology Incentives are available for installed measurements that can reduce electric demands as identified from Technical Assistance assessments.

How Technical Assistance and Technology Incentives works

Customers should contact SDG&E's Demand Response Department for an initial assessment of demand response potential. Where applicable, SDG&E will schedule an onsite assessment that will be performed by SDG&E personnel or a CEC approved engineering firm.

Customers will receive a preliminary assessment report with projected demand reduction potential. And if necessary, due to customized equipment or unique operations, a second more extensive assessment will be performed.

Based upon the results of either assessment, customers may choose to apply for Technical Incentives to implement demand reduction measures or to install demand reduction equipment. Examples of qualified incentives are smart thermostats, dual level lighting and enhanced automation. The incentive payment is $100/kW for reductions verified by SDG&E, not to exceed the total cost of equipment. Incentives will only be paid on measures or equipment that can actually produce quantifiable demand reduction.

The Technical Assistance and Technology Incentives programs give customers the necessary information and the means to participate in the voluntary Demand Response Programs.

Eligibility

Businesses with annual maximum demands equal to or greater than 20kW.

Technical Assistance and Technology Incentives are some of the ways that SDG&E is developing energy solutions. For more details on Technical Assistance and Technology Incentives contact your SDG&E Account Executive, call 866-377-4735 or email drp@semprautilites.com.

This program is available throughout California and is offered by the state's investor owned utilities.

Related Information

KWickview

Default CPP Rates

Contact DRP

Demand Response Overview Brochure

Energy Management Pyramid

Demand Response FAQs

APPENDIX B
SURVEY INSTRUMENTS

B1. 2005 Non-Participant Market Survey Instrument

2005 General Market Survey Instrument

INTRODUCTION

Hi, this is _______, I'm calling from Quantum Consulting on behalf of the [UTILITY] and the California Public Utilities Commission.

We are speaking with selected businesses and organizations to learn about their current energy usage and rate preferences. The Public Utilities Commission wants to better understand how businesses think about and manage their summer peak energy usage. Your input is very important to the Commission. May I speak with the person in your organization who is responsible for energy-related decisions for this facility?

The information you provide will be kept in strictest confidence. If you agree to participate in the survey, [UTILITY] will provide energy use and load information for your facility to the evaluation contractor. This information and your survey responses will be shared with the study team (the Utility Commission and its contractors, and [UTILITY]) only in a form that does not allow the identification of any business, individual or facility.

If utility contact information requested, please use the following:

SCE:	Edward Lovelace	(626) 302-1697
PG&E:	Susan McNicoll	(415) 973-7404
SDG&E:	Kevin McKinley	(858) 654-1142

SC1. First, what is your job title? [DON'T READ]

1	Facilities Manager	SC2
2	Energy Manager	SC2
3	Other facilities management/maintenance positio	SC2
4	Chief Financial Officer	SC2
5	Other financial/administrative position	SC2
6	Proprietor/Owner	SC2
7	President/CEO	SC2
8	Plant Manager	SC2
9	Controller	SC2
10	Engineer	SC2
11	Operations	SC2
77	Other (Specify)	SC2
88	Refused	SC2
99	Don't Know	SC2

RESP: Are you responsible for any other facilities in the [UTILITY] service territory other than the facility located at (address)(city)?

1	Yes	HOWMANY
4	No	F1
88	Refused	HOWMANY
99	Don't Know	HOWMANY

HOWMANY: How many facilities in the [UTILITY] service territory are you responsible for?

77	Enter Number	F1
88	Refused	F1
99	Don't Know	F1

Unless otherwise stated, all questions in this survey pertain to the facility located at (address)(city).

DR AWARENESS AND FAMILIARITY

First I'd like to ask you about your awareness of demand response programs being offered to [UTILITY] customers. For the purposes of this interview, *Demand Response* refers to actions customers take to temporarily reduce electricity demand in response to high electricity prices or to prevent system emergencies.

F1. California has developed several programs to promote demand response. Have you heard about any of these programs?

1	Yes	F1a
2	No	F2
88	Refused	F2
99	Don't Know	F2

[IF F1 = 1, then ask F1a; ELSE SKIP TO F2]

F1a. Which programs have you heard about? (Check all that apply)

1	Critical Peak Pricing	F2
2	Demand Bidding	F2
3	Demand Reserves Partnership	F2
4	Base Interruptible Program	F2
77	Other (specify____)	F2
88	Refused	F2
99	Don't Know	F2

F2. Next I'm going to read a brief description of a few specific demand response programs and then ask whether your organization is very familiar, somewhat familiar, or not at all familiar with each program.

F2a. [UTILITY'S] voluntary Critical Peak Pricing tariff. The voluntary Critical Peak Pricing (CPP) tariff can result in lower bills for customers who reduce electricity use during up to 12 critical peak periods per summer. Customers on the voluntary CPP tariff pay higher rates during these peak periods, but receive reduced energy rates at other times. How familiar is your organization with [UTILITY'S] voluntary *Critical Peak Pricing* (CPP) tariff? Would you say,

1	Very familiar	F2b
2	Somewhat familiar	F2b
3	Not at all familiar	F2b
88	Refused	F2b
99	Don't Know	F2b

F2b. [UTILITY'S] Demand Bidding Program. The Demand Bidding Program (DBP) is a no-risk program whereby participants earn bill credits for reducing their power usage during limited peak periods when contacted. How familiar is your organization with [UTILITY'S] *Demand Bidding Program* (DBP)?

1	Very familiar	F2d
2	Somewhat familiar	F2d
3	Not at all familiar	F2d
88	Refused	F2d
99	Don't Know	F2d

F2d. The California Demand Reserves Partnership (Cal-DRP) Program. Like the Demand Bidding Program, customers provide demand reductions during limited peak periods when contacted and receive payments for reductions. However, in this program customers work through a private sector energy services firm to aggregate their load with other customers. How familiar is your organization with the *Cal-DRP* program?

1	Very familiar	F2e
2	Somewhat familiar	F2e
3	Not at all familiar	F2e
88	Refused	F2e
99	Don't Know	F2e

F2e. [UTILITY'S] Base Interruptible Program. The Base Interruptible Program (BIP) provides bill credits to direct access and bundled service customers who reduce their demand to a pre-determined level within 30 minutes of a BIP event being called. In this program, participants who fail to reduce demand to the pre-determined level may face penalty charges. How familiar is your organization with [UTILITY'S] *Base Interruptible Program* (BIP)?

1	Very familiar	F6
2	Somewhat familiar	F6
3	Not at all familiar	F6
88	Refused	F6
99	Don't Know	F6

F6. In the past year, do you recall receiving any of the following types of information about [UTILITY'S] demand response programs?

F6a. A general discussion with your utility representative of demand response program features?

1	Yes	F6b
2	No	F6b
88	Refused	F6b
99	Don't Know	F6b

F6b. Specific analysis of the financial impact of participating in the new demand response programs from your utility representative?

1	Yes	F6c
2	No	F6c
88	Refused	F6c
99	Don't Know	F6c

F6c. Brochures and print materials about demand response programs?

1	Yes	F7
2	No	F7
88	Refused	F7
99	Don't Know	F7

[IF F6a, b, or c, = 1, then ask F7; ELSE SKIP TO BA1]

F7. How helpful was this information in determining whether demand response programs would be of interest to your organization?

1	Very helpful	BA1
2	Somewhat helpful	F7a
3	Not at all helpful	F7a
88	Refused	BA1
99	Don't Know	BA1

BARRIERS TO PARTICIPATION

Now I'd like to describe a few reasons some organizations might not be able to participate in demand response programs or, even if they did participate, could not reduce their demand very much. On a scale of 1 to 5, please tell me how significant each of the following are as concerns for your organization about participating in demand response programs. 1 indicates not significant and 5 indicates very significant. [ROTATE RANDOMLY]

BA1.	Effects on occupant comfort	
BA2.	Effects on production or productivity	
BA3.	Need for more information on how to achieve demand reductions	
BA4.	Permit regulations that limit the running of backup generators	
BA5.	Amount of potential bill savings	
BA6.	Risk of bill increases from level of on-peak prices and non-performance penalties	
BA7.	Time and effort it takes to participate	
BA8.	Inability to significantly reduce peak loads	
BA8b.	Length of curtailment time for individual events	

BA9. What other concerns, if any, does your organization have about trying to temporarily reduce summer peak loads at this location through participation in demand response programs?

1	No other concerns	CH1
2	Need a constant supply of power, cannot shift load	CH1
3	Need proof of benefits, costs, and savings	CH1
4	Need more program info	CH1
77	Other (specify_____)	CH1
88	Refused	CH1
99	Don't know	CH1

IMPACTS OF 2005 PROGRAM CHANGES ON PERCEIVED BARRIERS TO PARTICIPATION

Now I have a few questions about your organization's familiarity with changes made to [UTILITY'S] demand response programs between 2004 and 2005. These changes were made to try to increase customer participation in DR programs.

CH1. First I'd like to ask you about [UTILITY'S] *Bill Protection Incentive* for the voluntary Critical Peak Pricing program. How familiar is your organization with [UTILITY'S] Bill Protection Incentive?

1	Very familiar	CH1a
2	Somewhat familiar	CH1x
3	Not at all familiar	CH1x
88	Refused	CH1x
99	Don't Know	CH1x

[IF BA6 = 3, 4, or 5 and CH1 = 1, then ask CH1a;
IF BA6 = 3, 4, or 5 and CH1 = 2 or 3, then read CH1x;
ELSE SKIP TO CH2]

CH1x. Briefly, the Bill Protection Incentive provides customers with 100 percent protection against paying an annual electric bill greater than what they would pay under their current rate schedule for the first 12 months of participation in the voluntary CPP program.

CH1a. You indicated that your organization considers potential bill increases as a significant barrier to your organization's participation in CPP. To what extent does the Bill Protection Incentive address your organization's concerns about the risk of bill increases associated with the voluntary CPP program? Would you say it:

1	Addresses most of your concerns	CH2
2	Addresses some of your concerns	CH1b
3	Addresses none of your concerns	CH1b
88	Refused	CH2
99	Don't Know	CH2

[IF CH1a = 2 or 3, then ask CH1b; ELSE SKIP to CH2]

CH1b. And why is that?

77	Record Verbatim	CH2
88	Refused	CH2
99	Don't Know	CH2

CH2. There were also several changes to [UTILITY'S] Demand Bidding Program in 2005. How familiar is your organization with these changes in [UTILITY'S] Demand Bidding Program?

1	Very familiar	CH2a
2	Somewhat familiar	CH2a
3	Not at all familiar	CH2a
88	Refused	CH2a
99	Don't Know	CH2a

[IF BA8 = 3, 4, or 5 and CH2 = 1, then ask CH2a;

IF BA8 = 3, 4, or 5 and CH2 = 2 or 3, then read CH2x;
ELSE SKIP TO CH3]

CH2x. Briefly, the significant changes were that the program requirements were revised to lower the minimum load reduction requirement to [IF FLAG=PGE OR SCE: “50 kW” ELSE IF FLAG=SDG&E: “10% of average monthly max demand”] and allow customers to aggregate load reductions across facilities. In addition, the program no longer includes day-of event notification and all events are now notified on a day-ahead basis.

CH2a. You indicated that your organization considers the inability to temporarily reduce peak loads as a significant barrier to your participation in demand response programs. To what extent do the changes in the DBP program address your concerns about lack of reducible peak load at your facility?

1	Addresses most of your concerns	CH3
2	Addresses some of your concerns	CH2b
3	Addresses none of your concerns	CH2b
88	Refused	CH3
99	Don’t Know	CH3

[IF CH2a= 2 or 3, then ask CH2b; ELSE SKIP to CH3]

CH2b. And why is that?

77	Record Verbatim	CH3
88	Refused	CH3
99	Don’t Know	CH3

CH3. [UTILITY’S] Demand Response Technical Assistance and Incentives program was also changed significantly after 2004. How familiar is your organization with [UTILITY’S] Technical Assistance Incentive?

1	Very familiar	CH3a
2	Somewhat familiar	CH3a
3	Not at all familiar	CH3a
88	Refused	CH3a
99	Don’t Know	CH3a

[IF BA3 or BA7 = 3, 4, or 5 and CH3 = 1, then ask CH3a;
IF BA3 or BA7 = 3, 4, or 5 and CH3 = 2 or 3, then read CH3x;
ELSE SKIP TO CA3a]

CH3x. Briefly, [UTILITY’S] 2005 Demand Response Technical Assistance Incentive program provides customers with free on-site audits to help identify demand response load reduction opportunities, as well as financial incentives to realize the load reduction opportunities identified.

CH3a. You indicated that your organization considers time constraints and/or knowledge regarding how to temporarily reduce peak load at your facility as significant barriers to your participation in demand response programs. To what extent does the Technical Assistance Incentive address your concerns in these areas for your facility?

1	Addresses most of your concerns	CA1
2	Addresses some of your concerns	CH3b
3	Addresses none of your concerns	CH3b
88	Refused	CA1
99	Don't Know	CA1

[IF CH3a= 2 or 3, then ask CH3b; ELSE SKIP to CA3]

CH3b. And why is that?

77	Record Verbatim	CA1
88	Refused	CA1
99	Don't Know	CA1

DR CAPABILITY AND POTENTIAL ACTIONS

Now I am going ask you about your technical ability to temporarily reduce peak demand at this facility. Assume for this question that reductions would be requested for only a few hours on roughly twelve non-consecutive weekdays when summer temperatures are expected to be especially high.

CA1. What percentage of your afternoon peak demand could you potentially reduce for a few hours on twelve of the hottest summer days, provided you were notified the day before *and* given sufficient financial motivation?

1	0 percent	SA2
2	1 to 5 percent	SA2
3	6 to 10 percent	SA2
4	11 to 20 percent	SA2
5	21 to 50 percent	SA2
6	Over 50 percent	SA2
7	No amount would be adequate	SA2
88	Refused	SA2
99	Don't Know	SA2

SA2. What percentage of your annual electricity bill would you need to save as an incentive to reduce your demand at this location by 15% for a few hours on roughly twelve of the hottest summer weekdays?

1	0 percent	CA3a
2	1 to 5 percent	CA3a
3	6 to 10 percent	CA3a
4	11 to 20 percent	CA3a
5	21 to 50 percent	CA3a
6	Over 50 percent	CA3a
7	No amount would be adequate	CA3a
88	Refused	CA3a
99	Don't Know	CA3a

Now I have a couple of questions about your ability to view hourly load data at this facility.

CA3a. Do you have the ability to view this facility's *hourly* demand on an in-house energy information system?

1	Yes	CA3b
2	No	CA3b
88	Refused	CA3b
99	Don't Know	CA3b

CA3b. Do you have the ability to view this facility's hourly demand on a [UTILITY] provided website?

1	Yes	AT1
2	No	AT1
88	Refused	AT1
99	Don't Know	AT1

AUTOMATION TECHNOLOGY INVENTORY

Now I have a few questions about the equipment and controls capabilities at this facility.

AT1. Does this facility have an Energy Management and Control System (EMCS) for centrally controlling some or all of the heating, ventilation, and air conditioning system or other equipment?

1	Yes	AT1a
2	No	AT2
88	Refused	AT2
99	Don't Know	AT2

[IF AT1 = 1, then ask AT1a; ELSE SKIP TO AT2]

AT1a. And which of the following systems does your EMCS control?

1	Rooftop or other distributed HVAC units	AT1b
2	Central cooling plant	AT1b
3	Major ventilation fans	AT1b
4	Zone temperature	AT1b
5	Lighting equipment	AT2
6	Production processes	AT2
77	Other (specify_____)	AT2
88	Refused	AT2
99	Don't Know	AT2

AT1b. Does your EMCS offer the ability to control all of the space temperatures on an individual zone basis, that is, can it turn up or down each of the temperature set points individually?

1	Yes	AT1c
2	No	AT1c
88	Refused	AT1c
99	Don't Know	AT1c

AT1c. Does your EMCS offer the ability to control all of the space temperatures on a "global" basis, that is, can it turn up or down all of the space temperature set points using a simple screen or other centralized action?

1	Yes	AT2
2	No	AT2
88	Refused	AT2
99	Don't Know	AT2

AT2. What type of HVAC equipment controls the temperature of the occupied space(s) at your facility?

1	VAV boxes	AT2a
2	Constant volume mixing boxes	AT2a
77	Other (specify_____)	AT2a
88	Refused	AT2a
99	Don't Know	AT2a

AT2a. Is your facility's space temperature control system primarily pneumatic, direct digital control, or some of both?

1	Pneumatic	EA8
2	Direct digital controls	EA8

3	Some of both	EA8
88	Refused	EA8
99	Don't Know	EA8

AUTOMATION INVESTMENTS

EA8. In the past 2 years, has your organization considered any automation investments in order to improve your ability to manage your energy use at this facility?

1	Yes	EA9
2	No	AP1
88	Refused	AP1
99	Don't Know	AP1

[IF EA8 = 1, then ask EA9; ELSE SKIP TO AP1]

EA9. What are the reasons why your organization considered these upgrades to your control systems?

1	Save on energy costs	EA10
2	Upgrade old equipment	EA10
3	Increase flexibility of controls systems	EA10
4	Be able to respond to dynamic pricing	EA10
5	To increase occupant comfort	EA10
77	Other (specify_____)	EA10
88	Refused	EA10
99	Don't know	EA10

EA10. Did you actually install any of these control system upgrades for your business?

1	Yes	EA11
2	No	AP1
88	Refused	AP1
99	Don't Know	AP1

[IF EA10 = 1, then ask EA11; ELSE SKIP TO AP1]

EA11. And which upgrades did you choose to install?

1	Controls or EMS	AP1
2	Variable frequency drives	AP1
3	Programmable thermostat	AP1
4	Sensors or motion detectors	AP1
77	Other (specify_____)	AP1

88	Refused	AP1
99	Don’t Know	AP1

PUBLIC APPEALS PROGRAM AWARENESS

In addition to the incentive-based demand response programs we’ve discussed thus far, there are information campaigns in California that make appeals to the general public to temporarily reduce their electricity consumption during periods of extreme hot weather to help prevent system emergencies.

AP1. Do you recall receiving any alerts or notices to temporarily reduce your electricity demand during the summer of 2005?

1	Yes	AP1a
2	No	DE1
88	Refused	DE1
99	Don’t Know	DE1

[IF AP1 = 1, then ask AP1a; ELSE SKIP TO DE1]

AP1a. How many alerts or notices did you receive?

1	1	AP1b
2	2	AP1b
3	3	AP1b
4	4	AP1b
5	5	AP1b
6	More than 5	AP1b
88	Refused	AP1b
99	Don’t Know	AP1b

AP1b. Did you receive the notices via email, phone, television, radio, or some other means?

1	Email	AP1c
2	Phone	AP1c
3	Television	AP1c
4	Radio	AP1c
77	Other (specify_____)	AP1c
88	Refused	AP1c
99	Don’t Know	AP1c

AP1c. Were these notices associated with the *Flex Your Power Now* program?

1	Yes	AP1d
2	No	AP1d
88	Refused	AP1d
99	Don't Know	AP1d

AP1d. Upon hearing the notices, did your organization take action to temporarily reduce your electricity demand?

1	Yes	AP1c
2	No	DE1
88	Refused	DE1
99	Don't Know	DE1

[IF AP1d = 1, then ask AP1e; ELSE SKIP TO DE1]

AP1e. What action did you take? [DO NOT READ, CHECK ALL THAT APPLY]

1	Turned off/reduced overhead lighting	DE1
2	Turned off computers and other office equipment	DE1
3	Reduced thermostat temperature setting	DE1
4	Reduced or shut off some or all production processes	DE1
77	Other (specify_____)	DE1
88	Refused	DE1
99	Don't Know	DE1

DEFAULT CPP AWARENESS

Recently, the California Public Utilities Commission ordered utilities to file Critical Peak Pricing tariffs that, if approved, would automatically become the default rate for large customers unless they affirmatively choose to continue service on their current tariffs.

DE1. How familiar is your organization with the terms of [UTILITY'S] proposed default CPP tariff?

1	Very familiar	DE4
2	Somewhat familiar	DE4
3	Not at all familiar	DE6
88	Refused	DE6
99	Don't Know	DE6

[IF DE1 = 1 or 2, then ask DE4; ELSE SKIP TO DE6]

DE4. On average, do you think *most customers'* annual electricity bills would increase, decrease, or stay about the same as a result of taking service on [UTILITY'S] proposed default CPP rate?

1	Increase	DE4a
2	Decrease	DE4a
3	Stay about the same	DE5
88	Refused	DE5
99	Don't Know	DE5

[IF DE4 = 1 or 2, then ask DE4a; ELSE SKIP TO DE5]

DE4a. By approximately what percent do you think *most customers'* annual electricity bills would change? (Answer should be a percent number)

77	<NUMBER>	DE5
88	Refused	DE5
99	Don't Know	DE5

DE5. Would you expect *your* annual electricity bill to increase or decrease as a result of taking service on [UTILITY'S] proposed default CPP rate?

1	Increase	DE5a
2	Decrease	DE5a
3	Stay about the same	DE6
88	Refused	DE6
99	Don't Know	DE6

[IF DE5 = 1 or 2, then ask DE5a; ELSE SKIP TO DE6]

DE5a. By approximately what percent do you think *your* annual electricity bills would change? (Answer should be a percent number)

77	Record Verbatim	DE6
88	Refused	DE6
99	Don't Know	DE6

DE6. If your default service were in fact changed to a Critical Peak Pricing tariff, what questions would you need answered or what kinds of information would you need in order to make an informed decision about whether to stay on default CPP?

77	Record Verbatim	EM4
88	Refused	EM4
99	Don't Know	EM4

GENERAL ENERGY MARKET PERCEPTIONS

Now I have a couple of questions for you about your organization's perceptions of California's electricity market over the next few years.

EM4. Over the next three years, does your organization expect wholesale electricity prices to increase, decrease, or stay about the same?

1	Increase	EM5
2	Decrease	EM5
3	Stay about the same	EM5
88	Refused	EM5
99	Don't know	EM5

EM5. In your organization's view, how likely is it that California's power supplies will be *inadequate* to meet expected power demand over the next three years? Would you say:

1	Highly likely	EC1
2	Somewhat likely	EC1
3	Not sure	EC1
4	Somewhat unlikely	EC1
5	Very unlikely	EC1
88	Refused	EC1
99	Don't know	EC1

FIRMOGRAPHIC CHARACTERISTICS

Now I'd like to ask a few quick questions about this facility. Unless otherwise stated, all questions pertain to THIS FACILITY [RESTATE FACILITY LOCATION IF NECESSARY].

EC1. What is the main activity performed at this location?

1	Office	EC2
2	Retail (non-food)	EC2
3	College/university	EC2
4	School	EC2
5	Grocery store	EC2
6	Convenience store	EC2
7	Restaurant	EC2
8	Health care/hospital	EC2
9	Hotel or motel	EC2
10	Warehouse	EC2

11	Personal Service	EC2
12	Community Service/Church/Temple/Municipality	EC2
13	Industrial Electronic & Machinery	EC2
14	Industrial Mining, Metals, Stone, Glass, Concrete	EC2
15	Industrial Petroleum, Plastic, Rubber and Chemicals	EC2
16	Other Industrial	EC2
17	Agricultural	EC2
18	Transportation/Telecommunications/Utility	EC2
77	Other (SPECIFY)	EC2
88	Refused	EC2
99	Don't know	EC2

EC2. Approximately how many square feet does your organization occupy in this facility?

1	Less than 10,000 square feet	EC3
2	10,000 but less than 20,000 square feet	EC3
3	20,000 but less than 50,000 square feet	EC3
4	50,000 but less than 100,000 square feet	EC3
5	100,000 but less than 200,000 square feet	EC3
6	200,000 but less than 300,000 square feet	EC3
7	300,000 but less than 400,000 square feet	EC3
8	400,000 but less than 500,000 square feet	EC3
9	Over 500,000 square feet	EC3
10	Ag/Non-facility – Outdoors	EC3
88	Refused	EC3
99	Don't know	EC3

EC3. Does your organization...

1	Own this space	EC5
2	Lease this space	EC5
3	Own a portion and lease the remainder	EC5
88	Refused	EC5
99	Don't know	EC5

EC5. What percent of your organization's total annual operating costs do energy costs represent?

1	Less than 1 percent	EC5A
2	1 to 4 percent	EC5A
3	5 to 10 percent	EC5A
4	11 to 25 percent	EC5A
5	Over 25	EC5A

88	Refused	EC5A
99	Don't know	EC5A

EC5A. Has your organization assigned responsibility for controlling energy usage and costs to any of the following?

1	An in-house staff person	EC6
2	A group of staff	EC6
3	An outside contractor	EC6
4	No one	EC6
88	Refused	EC6
99	Don't know	EC6

EC6. Approximately how many locations does your organization have in California?

1	1	EC7
2	2 to 4	EC7
3	5 to 10	EC7
4	11 to 25	EC7
5	Over 25	EC7
88	Refused	EC7
99	Don't know	EC7

EC7. What is the approximate number of full-time equivalent workers of all types employed by your organization at this facility?

1	1 to 10	EC9A
2	11 to 50	EC9A
3	51 to 100	EC9A
4	100 to 250	EC9A
5	251 to 500	EC9A
7	501 to 1000	EC9A
8	Or, over 1000	EC9A
88	[Don't read] Refused	EC9A
99	[Don't read] Don't know	EC9A

EC9A. Which of the following is the LARGEST end use in terms of electricity consumption for this facility?

1	Lighting	EC9B
2	HVAC	EC9B
3	Continuous processing	EC9B
4	Batch processing	EC9B
5	Refrigeration	EC9B

77	Other, Specify______________	EC9B
88	Refused	EC9B
99	Don't know	EC9B

EC9B. And which would you say used the SECOND most electricity?

1	Lighting	EC10
2	HVAC	EC10
3	Continuous processing	EC10
4	Batch processing	EC10
5	Refrigeration	EC10
77	Other, Specify______________	EC10
88	Refused	EC10
99	Don't know	EC10

EC10. Does this location have any on-site electricity generators?

1	Yes, for backup/standby purposes only	
2	Yes, as an everyday supplement or replacement for electricity purchases from the grid	
3	No	
88	Refused	
99	Don't know	

[IF EC10 = 1 or 2, then EC10a; ELSE SKIP TO CL1]

EC10a. What percent of this location's electricity load can be met by your on-site generation?

______ Percent (allow > 100%)

EC10b. Are their legal restrictions on the number of hours your on-site system can run during the summer?

1	Yes	CL1
2	No	CL1
88	Refused	CL1
99	Don't know	CL1

CLOSE

CL1. Do you have any final comments or suggestions about demand response programs being offered by (IOU)?

<VERBATIM>

Those are all the questions I have for you. Thank you very much for your time.

B2. 2005 CPP and DBP Participant Post-Event Survey Instrument

2005 Post-Event Customer Survey Instrument

CPP and DBP Participants

Variables Needed:
Contact
Phone
Phone Extension
Cell Phones – check with Reps
PROGRAM – (CPP, DBP or "CPP and DBP")
CPP_FL – 0,1
DBP_FL – 0,1
Utility – PG&E, SCE, SDG&E
Prev_part – 1,0 – 2004 Participant

INTRODUCTION

SCREEN1 [WHEN RECEPTIONIST ANSWERS]:
May I speak with [Customer Contact], please?

INTRO1

Hello, this is ________________________, calling on behalf of [UTILITY] and the California Public Utilities Commission from Quantum Consulting. This is a fact-finding survey only – we are NOT selling anything, and responses will not be connected with your firm in any way.

INTRO1A

May I speak with the person in your organization who is responsible for decisions regarding demand reductions associated with the [PROGRAM1: CPP, DBP or CPP and DBP] program(s) at your facility?

INTRO1B NAME OF CONTACT: ____
INTRO1C TITLE: ____

IF RESPONDENT IS NOT AVAILABLE, GET HIS/HER NAME AND TITLE; MAKE ARRANGEMENTS TO CALL LATER

INTRO D

We are conducting a follow-up survey to determine how different businesses have responded to initial [PROGRAM: CPP, DBP or CPP and DBP] summer events. Are you the correct person to speak with regarding your organization's participation in recent [UTILITY] [PROGRAM: CPP, DBP, CPP and DBP] event(s)?

1	Yes	INTRO3
2	No	INTRO2A

INTRO3

As part of a CPUC-sponsored evaluation of current demand response programs, we are speaking with selected businesses and organizations to learn about their recent Participation in [UTILITY]'s [PROGRAM1: CPP, DBP, CPP and DBP] events. The feedback you provide will be used by [UTILITY] and the CPUC to help improve the Demand Response offerings available to California energy users.

The information you provide will be kept in strictest confidence and used only for purposes of this program evaluation. If you agree to participate in the survey, [UTILITY] will provide energy use and load information for your facility to the research contractor. This information and your survey responses will be shared with the study team (the Energy Commission and its contractors, and [UTILITY]) only in a form that does not allow the identification of any business, individual or facility.

This interview should take about 5 minutes. Is this a good time for you or is there a better time I can call you back?

If utility contact information requested, please use the following:

SCE:	Edward Lovelace	(626) 302-1697
PG&E:	Susan McNicoll	(415) 973-7404
SDG&E:	Leslie Willoughby	(858) 654-1262

SC1. First, what is your job title? [DON'T READ]

1	Facilities Manager	SC2
2	Energy Manager	SC2
3	Other facilities management/maintenance position	SC2
4	Chief Financial Officer	SC2
5	Other financial/administrative position	SC2
6	Proprietor/Owner	SC2
7	President/CEO	SC2
8	Plant Manager	SC2
9	Controller	SC2
10	Engineer	SC2
11	Operations	SC2
77	Other (Specify)	SC2
88	Refused	SC2
99	Don't Know	SC2

SC2. [UTILITY] has provided us information indicating that your organization is currently signed up to participate in the [PROGRAM:CPP, DBP or CPP and DBP] program(s). Is this correct?

1	Yes ONLY [PROGRAM]	SC3
2	No, signed up for DBP	SC3
3	No, signed up for CPP	SC3
4	No, signed up for CPP and DBP	SC3
5	No, not signed up for either CPP or DBP	T&T
88	Refused	T&T
99	Don't Know	T&T

[IF (CPP_FL=1 and SC2=1) or SC2 in (3,4) then ask SC3, else skip to SC4]

SC3. Are you responsible for multiple facilities in the [UTILITY] service territory that are signed up for CPP?

1	Yes	SC4
2	No	SC4
77	Other	SC4
88	Refused	SC4

99	Don't Know	SC4

[IF (DBP_FL = 1 and SC2=1) or SC2 in (2,4) then ask SC4]

SC4. Are you responsible for multiple facilities in the [UTILITY] service territory that are signed up for DBP?

1	Yes	DBP1
2	No	DBP1
77	Other	DBP1
88	Refused	DBP1
99	Don't Know	DBP1

DBP BIDDING

[IF (DBP_FL=1 and SC2(1)) or SC2(2|4)) THEN READ:

DBP1. Have you placed a bid for any of the 2005 DBP (Demand Bidding) events?

1	Yes	DBP2
2	No	DBP3
88	Refused	DBP7
99	Don't Know	DBP7

[IF DBP1=1 and SC4=1 then ask DBP2]

DBP2. Did you place bids at all of the facilities that you are responsible for?

1	Yes	DBP4
2	No	DBP3
88	Refused	DBP4
99	Don't Know	DBP4

[IF DBP1=2 then ask DBP3A]

DBP3A. Why not?

[Probe for complete answer – i.e. if they say they weren't notified find out was it because the page didn't go through or because they didn't have their pager on them at the time?]

1	Operation was already was shut down	DBP4
2	Don't need to take action to save money	DBP4
3	Could not respond that fast	DBP4
4	Not avail to bid that hour	DBP4
5	Never planning to bid	DBP4
6	Could not reduce load on that particular day	DBP4
7	System Issue /No password	DBP4
8	Does not make sense financially for us to bid	DBP4
77	<RECORD VERBATIM>	DBP4
88	Refused	DBP4
99	Don't Know	DBP4

[IF DBP2=2 then ask DBP3B]

DBP3B. Why not?

[Probe for complete answer – i.e. if they say they weren't notified find out was it because the page didn't go through or because they didn't have their pager on them at the time?]

1	Operation was already was shut down	DBP4
2	Don't need to take action to save money	DBP4
3	Could not respond that fast	DBP4
4	Not avail to bid that hour	DBP4
5	Never planning to bid	DBP4
6	Could not reduce load on that particular day	DBP4
7	System Issue /No password	DBP4
8	Does not make sense financially for us to bid	DBP4
77	<RECORD VERBATIM>	DBP4
88	Refused	DBP4
99	Don't Know	DBP4

[IF DBP1=1 then ask DBP4]

DBP4. Have you encountered any problems in your attempts to bid?

[Read only if necessary: such as password problems, problems logging on to the system, missing bidding deadline, etc.]

1	Yes	DBP5
2	No	DBP7
88	Refused	DBP7
99	Don't Know	DBP7

[IF DBP4=1 then ask DBP5 and DBP6]

DBP5. What type of problem?

1	Problem with password /logging onto website	DBP6
2	Missed bidding deadline	DBP6
3	Could not respond in 1 hour	
4	Received Notice too late	
77	Other	DBP6
88	Refused	DBP6
99	Don't Know	DBP6

DBP6. Was [UTILITY] able to help you resolve this problem?

1	Yes	DBP7
2	No	DBP7
88	Refused	DBP7
99	Don't Know	DBP7

DBP7 (formerly DBP5A). What is the likelihood that you will place bids for future DBP events? Would you say you are ….. (Can select 1-5 and 77)

1	Very Likely	DBP8
2	Somewhat Likely	DBP8
3	Neither Likely nor unlikely	DBP8
4	Somewhat unlikely	DBP8
5	Not at all Likely	DBP8

88	Refused	DBP8
99	Don't Know	DBP8

DBP8. Is there anything that [Utility] can do to help you bid on future DBP events?

1	Lower Load Reduction Requirement	DR1
2	Provide more training	DR1
3	Increase Incentives	DR1
4	Notify Additional People	DR1
5	Nothing	DR1
77	<RECORD VERBATIM>	DR1
88	Refused	DR1
99	Don't Know	DR1

DR ACTIONS TAKEN

[IF DBP1=2 READ: "Even though you did not bid on a DBP event…."]

DR1 (formerly CPP1_A). Have you taken demand reduction actions in response to any of the recent [PROGRAM: CPP, DBP, CPP and DBP] events?

1	Yes	DR2
2	No	DR4
88	Refused	DR15
99	Don't Know	DR15

[IF DR1=1 and DBP_FL = 1 then ask DR2_DBP]

DR2_DBP. Did you take action for all of the recent DBP events?

1	Yes – ALL DBP Events	DR3
2	Some DBP Events	DR4
3	None of the DBP Events	DR3
88	Refused	DR5
99	Don't Know	DR5

[IF DR1=1 and CPP_FL = 1 then ask DR2_CPP]

DR2_CPP. Did you take action for all of the recent CPP events?

1	Yes – ALL CPP Events	DR3
2	Some CPP Events	DR4
3	None of the CPP Events	DR3
88	Refused	DR5
99	Don't Know	DR5

[IF DR1=1 and (SC3 = 1 or SC4 = 1) then ask DR3]

DR3. Did you take demand reduction actions at all of your participating facilities?

1	Yes	DR5
2	No	DR4
88	Refused	DR5
99	Don't Know	DR5

[IF (DR1=2 and CPP_FL = 1) then ask DR4A – CPP and didn't take any action]

DR4A. Why didn't you take action for the CPP events?

[Probe for complete answer – i.e. if they say they weren't notified find out was it because the page didn't go through or because they didn't have their pager on them at the time?]

1	Operation was already was shut down	DR5
2	Don't need to take action to save money	DR5
3	Could not respond that fast	DR5
4	Not Available to Bid	DR5
5	Never planning to bid	DR5
6	Could not reduce load	DR5
7	Do not remember why	DR5
8	Was not a mandatory reduction	DR5
9	Doesn't make sense financially for us	DR5
77	<RECORD VERBATIM>	DR5
88	Refused	DR5
99	Don't Know	DR5

[IF DR1 = 1 and ((DR2_CPP = 2,3 or DR2_DBP = 2,3) or DR3 = 2) then ask DR4B]

DR4B. What are the reasons you did not take demand response action for all of these events and/or all of your facilities?

[Probe for complete answer – i.e. if they say they weren't notified find out was it because the page didn't go through or because they didn't have their pager on them at the time?]

1	Operation was already was shut down	DR5
2	Don't need to take action to save money	DR5
3	Could not respond that fast	DR5
4	Not Available to Bid	DR5
5	Never planning to bid	DR5
6	Could not reduce load	DR5
7	Do not remember why	DR5
8	Was not a mandatory reduction	DR5
9	Doesn't make sense financially for us	DR5
77	<RECORD VERBATIM>	DR5
88	Refused	DR5
99	Don't Know	DR5

[IF DBP1 = 1 and DR1=2 then ask DR4C]

DR4C. Why did you place a bid and then not take any demand reduction actions?

[Probe for complete answer – i.e. if they say they weren't notified find out was it because the page didn't go through or because they didn't have their pager on them at the time?]

1	Operation was already was shut down	DR5
2	Don't need to take action to save money	DR5
3	Could not respond that fast	DR5
4	Not Available to Bid	DR5
5	Never planning to bid	DR5
6	Could not reduce load	DR5
7	Do not remember why	DR5
8	Was not a mandatory reduction	DR5

9	Doesn't make sense financially for us	DR5
77	<RECORD VERBATIM>	DR5
88	Refused	DR5
99	Don't Know	DR5

[IF DR1 = 1 then READ: For the next brief series of questions, I would like to discuss the specific DR actions you have taken in response to the recent <%PROGRAM> events. If your responses differed significantly across events, please respond based on your "TYPICAL" response.

NOTE TO INTERVIEWERS (DO NOT READ): If they say their most typical response was to do nothing but for at least one event they have taken action tell them to base their responses on the event for which they did take action]

[IF DR1 = 1 then ask DR5]

DR5 (formerly EV10). What type of demand reduction actions have you taken in response to recent Demand Response events?

1	Used backup generators	DR6
2	Allowed the temperature to rise in the occupied space	DR6
3	Reduced overhead lighting	DR6
4	Reduced or shut off some or all production processes?	DR6
5	Shut Down Completely	DR6
6	Turned off non-critical equipment	DR6
7	Shut Down Partially	DR6
8	Rescheduled EMS	DR6
77	<RECORD VERBATIM>	DR6
88	Refused	DR6
99	Don't Know	DR6

[IF (CPP_FL = 1 and DBP_FL = 1) or SC2 = 4 then ask DIFF1]

DIFF1. Have your demand reduction actions differed between CPP events and DBP events?

1	Yes	DIFF2
2	No	DR6
88	Refused	DR6
99	Don't Know	DR6

[If DIFF1 = 1]

DIFF2. In what ways?

77	<RECORD VERBATIM>	DR6
88	Refused	DR6
99	Don't Know	DR6

[IF DR1 = 1 and DBP1=1 then ask DR6]

DR6 (formerly DBP1_F). How did your actual load reduction for DBP events compare to the demand reduction you bid? Was it…

1	Close to what was bid	DR7
2	Much LESS THAN what was bid, OR	DR6B
3	Much MORE THAN what was bid	DR6B

77	<RECORD VERBATIM>	DR7
88	Refused	DR7
99	Don't Know	DR7

[IF DR6 = 2 or 3]

DR6B (formerly DBP1_G). Why was your actual load reduction different from what you bid?

1	Incentives were too low, not worth lost productivity	DR7
2	Because I was able to reduce MORE	DR7
3	Because I was not able to reduce that much	DR7
4	Baseline doesn't work for us	DR7
5	Didn't have time to track curtailment	DR7
77	<RECORD VERBATIM>	DR7
88	Refused	DR7
99	Don't Know	DR7

[If DR1 = 1 and DR5 in (1-8 or 77) then ask DR7 and DR8]

DR7. Did you implement any of your load reductions through an EMS or similar control system?

1	Yes	DR8
2	No	DR8
88	Refused	DR8
99	Don't Know	DR8

DR8 (formerly EV10a). What level of automation was used to implement these demand reduction actions? Were they….

1	Fully Automated	DR9
2	Partially Automated	DR9
3	Manual	DR9
4	Does Not Apply (NOT READ)	DR9
77	RECORD VERBATIM	DR9
88	Refused	DR9
99	Don't Know	DR9

DR9 (formerly EV13). Did you experience any impacts on your organization in terms of personnel comfort or productivity as a result of your demand reduction actions? (Open end next)

1	Yes	IMPACT
2	No	DR12
88	Refused	DR12
99	Don't Know	DR12

[If DR9 = 1 then ask IMPACT and COST]

IMPACT. Please explain the impacts your organization experienced. (Do not Read)

1	Staff Complaints (lost hours, etc.)	COST
2	Warm/Uncomfortable Work Environment	COST
3	Lost Production	COST
4	Financial Impact	COST
5	Safety Concerns over limited lighting	COST
77	<RECORD VERBATIM>	COST
88	Refused	COST

99	Don't Know	COST

COST. Please estimate the cost of any of these production or productivity losses?

1	No	LABOR
77	<RECORD VERBATIM>	LABOR
88	Refused	LABOR
99	Don't Know	LABOR

[IF DR1 = 1]

LABOR. Can you provide an estimate of the labor hours expended to manage a demand reduction event?

1	Less than 1 hour	DR15
2	1-2 hours	DR15
3	3-4 hours	DR15
4	5-8 hours	DR15
5	More than 8 hours	DR15
77	<RECORD VERBATIM>	DR15
88	Refused	DR15
99	Don't Know	DR15

DR15. Do you have a plan detailing the demand reduction actions that you will take in response to future events?

1	Yes	DR16
2	No	DR20
88	Refused	DR20
99	Don't Know	DR20

[If DR15 = 1 then ask DR16]

DR16. What was most helpful in designing your demand reduction action plan?

77	<RECORD VERBATIM>	DR17
88	Refused	DR17
99	Don't Know	DR17

[If Customer has curtailed (DR1 = 1) AND they have a plan (DR15 = 1) then ask DR17]

DR17. Does your load reduction plan differ from how your have responded to Demand Reduction events this summer?

1	Yes	DR18
2	No	DR19
88	Refused	DR19
99	Don't Know	DR19

[If Plan is different (DR17 = 1) OR they haven't reduced but they have a plan (DR1=2 and DR15=1) then ask DR18]

DR18. What type of demand reduction actions does your plan call for?

1	Used backup generators	DR19
2	Allowed the temperature to rise in the occupied space	DR19
3	Reduced overhead lighting	DR19
4	Reduced or shut off some or all production processes?	DR19
5	Shut Down Completely	DR19

6	Turned off non-critical equipment	DR19
7	Shut Down Partially	DR19
8	Rescheduled EMS	DR19
77	<RECORD VERBATIM>	DR19
88	Refused	DR19
99	Don't Know	DR19

[If Customer has a plan (DR15 = 1) then ask DR19]

DR19. Please provide an estimate of the person (man) days expended to prepare your demand response plans and to do internal testing prior to events?

1	Less than 1/2 day	DR20
2	Between ½ day and 1 day	DR20
3	2-3 days	DR20
4	4-7 days	DR20
5	More than 7 days	DR20
77	<RECORD VERBATIM>	DR20
88	Refused	DR20
99	Don't Know	DR20

DR20. Did you take advantage of any utility assistance services to help you prepare for a demand response event?

1	Yes	DR21
2	No	DR21
88	Refused	DR21
99	Don't Know	DR21

[If DR20 = 1 then ask DR21 and DR22]

DR21. What type of utility assistance did you utilize?

1	Technical Assistance	DR22
2	Participant Meetings/Seminars/Workshops	DR22
77	<RECORD VERBATIM>	DR22
88	Refused	DR22
99	Don't Know	DR22

DR22. Was the utility assistance useful in helping you fully respond to recent event notification(s)?

1	Yes	DR23A
2	No	DR23A
88	Refused	DR23A
99	Don't Know	DR23A

[If (CPP_FL = 1 and SC2=1) or SC2 in (3,4) then ask DR23A]

DR23A (formerly CPP4A). What is the likelihood that you to take demand reduction actions for future CPP events? (Can select 1-5 and 77)

1	Very Likely	DR23B
2	Somewhat Likely	DR23B
3	Neither Likely nor unlikely	DR23B
4	Somewhat unlikely	DR23B

5	Not at all Likely	DR23B
88	Refused	DR23B
99	Don't Know	DR23B

[If (DBP_FL = 1 and SC2=1) or SC2 in (2,4) then ask DR23B]

DR23B (formerly DBP4A). What is the likelihood that you to take demand reduction actions for future DBP events? (Can select 1-5 and 77)

1	Very Likely	DR24
2	Somewhat Likely	DR24
3	Neither Likely nor unlikely	DR24
4	Somewhat unlikely	DR24
5	Not at all Likely	DR24
88	Refused	DR24
99	Don't Know	DR24

DR24 (formerly CPP4B). Is there anything that [Utility] can do to help you take Demand Reduction actions for future Demand Response events?

1	Lower Load Reduction Requirement	DR1
2	Provide more training	DR1
3	Increase Incentives	DR1
4	Notify Additional People	DR1
5	Nothing	DR1
77	<RECORD VERBATIM>	DR1
88	Refused	DR1
99	Don't Know	DR1

[If DR1=1]

EV12a. Prior to the events you participated in, did you increase your energy usage for a period of time to make up for the reduction that was about to occur?

1	Yes	PRIOR
2	No	EV12b
88	Refused	EV12b
99	Don't Know	EV12b

[If EV12a=1]

PRIOR. What actions did you take that increase your energy use PRIOR to the reduction period? (i.e. pre-cooling)

1	Ran Extra Shifts	EV12b
2	Increased Production in off-shifts	EV12b
3	Pre-Cooled the building	EV12b
77	<RECORD VERBATIM>	EV12b
88	Refused	EV12b
99	Don't Know	EV12b

[If DR1=1]

EV12b. After the event was over, did you increase your energy use for a period of time to make up for any reductions resulting from the event?

1	Yes	AFTER
2	No	EV13
88	Refused	EV13
99	Don't Know	EV13

[If EV12b=1]

AFTER. What actions did you take that increase your energy use AFTER the reduction period?

1	Ran Extra Shifts	DR25
2	Increased Production in off-shifts	DR25
77	<RECORD VERBATIM>	DR25
88	Refused	DR25
99	Don't Know	DR25

[If (CPP_FL = 1 and SC2=1) or SC2 in (3,4) then ask DR25]

DR25. Have you adjusted your summer load shape since signing up for the CPP program to take advantage of reduced on-peak and mid-peak prices or demand charges during non-CPP event hours?

1	Yes	ADJUST
2	No	DR26
88	Refused	DR26
99	Don't Know	DR26

[If DR25=1]

ADJUST. How have you adjusted it?

77	<RECORD VERBATIM>	ES12A
88	Refused	ES12A
99	Don't Know	ES12A

GENERAL PROGRAM FEEDBACK

ES12A-ES12D. Next I would like to ask you a few general questions about your experience with the [PROGRAM} program and the reasons why your organization decided to participate. On a 1 to 5 scale, where 1 indicates insignificant and 5 indicates extremely significant, please indicate how significant each of the following reasons was to your organizations decision to participate in the [PROGRAM] program. [ROTATE RANDOMLY]
How significant a reasons is ….

ES12A.	Being a good corporate citizen	ES12E
ES12B.	Avoiding rolling blackouts	ES12E
ES12C.	The amount of potential bill savings	ES12E
ES12D.	Being able to participate in the program without significantly affecting your business operations.	ES12E

[IF ES12C in (3,4,5)]

ES12E. You stated that the potential bill savings was important to your organizations decision to participate in the [PROGRAM] program. Have the financial incentives associated with the program met your expectations?

1	Yes	ES12F
2	Somewhat	ES12F
3	No	ES12F
88	Refused	ES12F
99	Don't Know	ES12F

[If ES12E=3]

ES12F. Why is that?

77	<RECORD VERBATIM>	ES12G
88	Refused	ES12G
99	Don't Know	ES12G

[IF ES12B in (3,4,5)]

ES12G. You just stated that avoiding rolling blackouts was important to your organization's decision to participate in the [PROGRAM] program. Do you feel that your participation ***is*** having a positive effect on [UTILITY]'s ability to maintain system reliability?

1	Yes	ES12H
2	Somewhat	ES12H
3	No	ES12H
88	Refused	ES12H
99	Don't Know	ES12H

[If ES12G=3]

ES12H. Why is that?

77	<RECORD VERBATIM>	EV15_CPP
88	Refused	EV15_CPP
99	Don't Know	EV15_CPP

[If (CPP_FL = 1 and SC2=1) or SC2 in (3,4) then ask ES15_CPP]

ES15_CPP. Overall, how satisfied are you with your participation in the CPP program? Would you say you are …. (Next question is an open-end to capture why)

1	Very satisfied	ES16_CPP
2	Somewhat satisfied	ES16_CPP
3	Somewhat dissatisfied	ES16_CPP
4	Very dissatisfied	ES16_CPP
88	Refused	ES17_CPP
99	Don't Know	ES17_CPP

[If ES15_CPP in 1 to 4 then ask ES16_CPP]

ES16_CPP. Why is that?

77	<RECORD VERBATIM>	ES20_DBP
88	Refused	ES20_DBP
99	Don't know	ES20_DBP

[If (DBP_FL = 1 and SC2=1) or SC2 in (2,4) then ask ES20_DBP]

ES20_DBP. Overall, how satisfied are you with your participation in the DBP program? Would you say you are …. (Next question is an open-end for the why)

1	Very satisfied	ES21_DBP
2	Somewhat satisfied	ES21_DBP
3	Somewhat dissatisfied	ES21_DBP
4	Very dissatisfied	ES21_DBP
88	Refused	ES22_DBP
99	Don't Know	ES22_DBP

[If ES20_DBP in 1 to 4 then ask ES21_DBP]

ES21_DBP. Why is that?

77	<RECORD VERBATIM>	DR26
88	Refused	DR26
99	Don't know	DR26

[IF Participated in Program last summer = Prev_Part = 1 then ask DR26]

DR26. Our records indicated that your organization participated in a demand response program last summer. Has your organization learned anything new since last summer that has helped you respond to this summers events?

1	Yes	LEARN
2	No	EV14
3	Did not participate in 2004	EV14
88	Refused	EV14
99	Don't Know	EV14

[If DR26=1]

LEARN. What have you learned?

77	<RECORD VERBATIM>	EV14
88	Refused	EV14
99	Don't Know	EV14

READ: We are almost finished; I just have a few more questions for you.

EV14. In your opinion, how effective was the process by which you were notified of the event(s)? Would you say it was ….

1	Very effective	EV15
2	Somewhat effective	EV15
3	Somewhat ineffective (open end next)	EV14a
4	Very ineffective (open end next)	EV14a
5	Wasn't Notified	EV15
88	Refused	EV15
99	Don't Know	EV15

[IF EV14 in (3,4)]

EV14A: Why do you say that?

1	Notice was too late, not enough time to bid	FEED1
2	Notice was emailed and didn't check email	FEED1
3	Cannot bid if out of the office	FEED1
4	No follow up after initial call	FEED1
77	<RECORD VERBATIM>	FEED1
88	Refused	FEED1
99	Don't Know	FEED1

[If took action – DR1=1 or placed bid DBP1 = 1]

FEED1. Have you used the online tool to monitor your electricity usage before or during one of the recent events? (DO NOT READ- If needed you can tell participant name of the tool we are referring to. Online Tools: SDG&E=Quickview, SCE= SCE's Energy Manager Web site, PG&E=InterAct)

1	Yes	FEED2
2	No	FEED4
3	Don't Have Tool	FEED4
4	Don't know how to use tool	FEED3
88	Refused	FEED4
99	Don't Know	FEED4

[IF FEED1 = 1]

FEED2. Did the tool give you the information necessary to effectively manage your events?

1	Yes	FEED3
2	No	FEED3
88	Refused	FEED3
99	Don't Know	FEED3

[IF FEED1 = 1]

FEED3. How would you rate the ease of use of the online tool? Would you say it was …

1	Easy	FEED4
2	Somewhat Difficult	FEED3
3	Very Difficult	FEED3
88	Refused	FEED3
99	Don't Know	FEED3

CLOSE

READ: And finally, …

CL1. Do you have any comments or input regarding your experiences with these demand response events?

1	No Comments	CL2
77	<RECORD VERBATIM>	CL2
88	Refused	CL2

99	Don't Know	CL2

Those are all the questions I have for you today. Thank you very much for your time.

B3. 2005 CPP and DBP Participant End of Summer Survey Instrument

2005 End of Summer Survey Instrument

Variables Needed:
Contact *
Phone*
Phone Extension
Cell Phones
PROGRAM**
CPP_FL – 0,1 & DBP_FL – 0,1
Utility – PG&E, SCE, SDG&E
Prev_part – 1,0 – 2004 Participant
Recall = 1 (previously called)

Responses various previous questions:
DBP1_old – Previous Bidding
DR1_old – Previous demand reductions
DR25_old – CPP load shape
DR23A_old & DR23B_old–Likelihood questions
Title_old
Vername_old

INTRODUCTION

SCREEN1 [WHEN RECEPTIONIST ANSWERS]:
May I speak with [CONTACT] the [TITLE], please?

[IF RECALL = 0 then read INTRO1A]
INTRO1A
Hello, this is ______________________, calling on behalf of [UTILITY] and the California Public Utilities Commission from Quantum Consulting. This is a fact-finding survey only – we are NOT selling anything, and responses will not be connected with your firm in any way.

INTRO1A
May I speak with the person in your organization who is responsible for decisions regarding demand reductions associated with the [PROGRAM] program(s) at your facility?

NAME OF CONTACT: ___________________________
TITLE: ______________________________________

IF RESPONDENT IS NOT AVAILABLE, GET HIS/HER NAME AND TITLE; MAKE ARRANGEMENTS TO CALL LATER

INTRO1B
We are conducting a follow-up survey to determine how different businesses have responded to initial [PROGRAM] summer events. Are you the correct person to speak with regarding your organization's participation in 2005 [UTILITY] [PROGRAM] event(s)?

1	Yes	
2	No	

[IF RECALL = 1 read INTRO2A]
INTRO2A
Hello, this is ______________________, calling on behalf of [UTILITY] and the California Public Utilities Commission from Quantum Consulting.
We are calling today to follow-up on a survey we conducted a few months ago regarding how your organization responded to initial [PROGRAM] summer events. This is a fact-finding survey

only – we are NOT selling anything.

SAME_PERSON: Are you the person we previously spoke with?

1	Yes	INTRO3
2	No	INTRO2B
88	Refused	
99	Don't Know	INTRO2B

[If person DOES NOT match the name we previously surveyed read INTRO2a]

INTRO2B

Hello, this is ______________________, calling on behalf of [UTILITY] and the California Public Utilities Commission from Quantum Consulting.

We are calling today to follow-up on a survey we conducted with [CONTACT] the [TITLE] a few months ago - This is a fact-finding survey only – we are NOT selling anything.

AVAIL: Is he or she available?

1	Yes	INTRO1
2	No	INTRO2C
88	Refused	INTRO2C
99	Don't Know	INTRO2C

[If YES – READ INTRO2A when they come on, If NO – READ INTRO 2C]

INTRO2C : Would there be another person in your organization who I could speak with about decisions regarding demand reductions associated with the [PROGRAM] program(s) at your facility?

NAME OF CONTACT: ____________________________________

TITLE: ____________________________________

IF RESPONDENT IS NOT AVAILABLE, GET HIS/HER NAME AND TITLE; MAKE ARRANGEMENTS TO CALL LATER

[Once the right person is on the phone read INTRO3]

INTRO3

As a final component of a CPUC-sponsored evaluation of current demand response programs, we are speaking with selected organizations to gain feedback regarding their participation in [UTILITY]'s [PROGRAM1] program(s) for the summer of 2005. The feedback you provide will be used by [UTILITY] and the CPUC to help improve the Demand Response offerings available to California energy users and will be kept in strictest confidence. Your survey responses will be shared with the study team (the Energy Commission and its contractors, and [UTILITY]) only in a form that does not allow the identification of any business, individual or facility.

This interview should take about 15 minutes. Is this a good time for you or is there a better time I can call you back?

If utility contact information requested, please use the following:

SCE:	Edward Lovelace	(626) 302-1697
PG&E:	Susan McNicoll	(415) 973-7404
SDG&E:	Kevin McKinley	(858) 654-1142

SC1. First, what is your job title? [DON'T READ]

1	Facilities Manager	SC2
2	Energy Manager	SC2
3	Other facilities management/maintenance position	SC2
4	Chief Financial Officer	SC2
5	Other financial/administrative position	SC2
6	Proprietor/Owner	SC2
7	President/CEO	SC2
8	Plant Manager	SC2
9	Controller	SC2
10	Engineer	SC2
11	Operations	SC2
77	Other (Specify)	SC2
88	Refused	SC2
99	Don't Know	SC2

SC2. [UTILITY] provided us information indicating that your organization is signed up to participate in the [PROGRAM] program(s). Is this still correct?

1	Yes ONLY [PROGRAM]	SC3
2	No, signed up for DBP	SC3
3	No, signed up for CPP	SC3
4	No, signed up for CPP and DBP	SC3
5	No, not signed up for either CPP or DBP	T&T
88	Refused	T&T
99	Don't Know	T&T

[IF Recall = 0 and ((CPP_FL=1 and SC2=1) or SC2 in (3,4)) then ask SC3, else skip to SC4]

SC3. Are you responsible for multiple facilities in the [UTILITY] service territory that are signed up for CPP?

1	Yes	SC4
2	No	SC4
77	Other	SC4
88	Refused	SC4
99	Don't Know	SC4

[IF Recall = 0 and ((DBP_FL = 1 and SC2=1) or SC2 in (2,4)) then ask SC4]

SC4. Are you responsible for multiple facilities in the [UTILITY] service territory that are signed up for DBP?

1	Yes	DBP1
2	No	DBP1
77	Other	DBP1
88	Refused	DBP1
99	Don't Know	DBP1

PARTICIPATION SUMMARY

Read:"For this next set of questions I would like to ask you to think about your overall experience with the [PROGRAM] program for this past summer."

Start CPP Battery: [If (CPP_FL=1 and SC2(1)) or SC2(3|4)]

ES1. Thinking back over the summer (May-Present), how many events would you say were called for the CPP program? (Do Not Read: Get a guess unless they have no idea)

0-12	Key in Number	ES2A
13	More than 12	ES2A
14	Refused	ES2A
15	Don't know	ES2A

ES2A. Were there more CPP Events than you expected, about as many as you expected, or fewer than you expected?

1	More than I expected	ES2B
2	About what I expected	ES2B
3	Fewer than I expected	ES2B
88	Refused	ES2B
99	Don't know	ES2B

[If ES1 in (1-13)]

ES2B. For how many of the [ES1] CPP events was your organization able to reduce your energy usage?

0-12	Key in Number	ES3
13	More than 12	ES3
14	Refused	ES3
15	Don't know	ES3

[IF Recall = 0 and (ES2B = 0 or (ES2B < ES1 and ES1 in 1-13)) then ask DR4A]

DR4A. Why didn't you take demand reduction actions for some of the CPP events?

[Probe for complete answer – i.e. if they say they weren't notified find out was it because the page didn't go through or because they didn't have their pager on them at the time?]

1	Operation was already was shut down	DR5_CPP
2	Don't need to take action to save money	DR5_CPP
3	Could not respond that fast	DR5_CPP
4	Not Available to Bid	DR5_CPP
5	Never planning to bid	DR5_CPP
6	Could not reduce load	DR5_CPP
7	Do not remember why	DR5_CPP
8	Was not a mandatory reduction	DR5_CPP
9	Doesn't make sense financially for us	DR5_CPP
77	<RECORD VERBATIM>	DR5_CPP
88	Refused	DR5_CPP
99	Don't Know	DR5_CPP

[IF Recall = 0 and ES2B in 1-13 then ask DR5_CPP]

DR5_CPP. What type of demand reduction actions have you taken in response to 2005 CPP events?

1	Used backup generators	DR23A
2	Allowed the temperature to rise in the occupied space	DR23A
3	Reduced overhead lighting	DR23A
4	Reduced or shut off some or all production processes?	DR23A
5	Shut Down Completely	DR23A
6	Turned off non-critical equipment	DR23A
7	Shut Down Partially	DR23A

8	Rescheduled EMS	DR23A
77	<RECORD VERBATIM>	DR23A
88	Refused	DR23A
99	Don't Know	DR23A

[If recall = 0 or (recall = 1 and sc2 = 4) then ask DR23A]

DR23A (formerly CPP4A). What is the likelihood that you will take demand reduction actions for future CPP events? (Can select 1-5)

1	Very Likely	ES3
2	Somewhat Likely	ES3
3	Neither Likely nor unlikely	ES3
4	Somewhat unlikely	ES3
5	Not at all Likely	ES3
88	Refused	ES3
99	Don't Know	ES3

End CPP Battery

Start DBP Battery: [If (DBP_FL=1 and SC2(1)) or SC2(2|4)]

ES3. Thinking back over the summer (May-Present), how many events would you say were called for the DBP program? (Can you give me your best guess)

0- 20	Key in Number	ES4
21	More than 20	ES4
22	Refused	ES4
23	Don't know	ES4

ES4. Were there more DBP Events than you expected, about as many as you expected, or fewer than you expected?

1	More than I expected	ES5
2	About what I expected	ES5
3	Fewer than I expected	ES5
88	Refused	ES5
99	Don't know	ES5

[If ES3 in (1-21)]

ES5. For how many of those [ES3] DBP events did your organization submit a bid?

0- 20	Key in Number	ES5B
21	More than 20	ES5B
22	Refused	ES5B
23	Don't know	ES5B

[IF (ES5 = 0 or (ES5< ES3 and ES3 in 1-21)) then ask ES5B and Bid4]

ES5B(DBP3a). Why didn't you place a bid for some of the DBP events?

[Probe for complete answer – i.e. if they say they weren't notified find out was it because the page didn't go through or because they didn't have their pager on them at the time?]

1	Operation was already was shut down	BID4
2	Don't need to take action to save money	BID4
3	Could not respond that fast	BID4
4	Not avail to bid that hour	BID4

5	Never planning to bid	BID4
6	Could not reduce load on that particular day	BID4
7	System Issue /No password	BID4
8	Does not make sense financially for us to bid	BID4
77	<RECORD VERBATIM>	BID4
88	Refused	BID4
99	Don't Know	BID4

Bid4. Would extending the bidding window to 2 hours increase your bidding activities?

1	Yes	BID5
2	No	ES6
88	Refused	ES6
99	Don't know	ES6

[If Bid4 = 1]

Bid5. If the bidding window was extended, would you prefer to be notified one hour earlier or having the bidding deadline extended one hour later?
(If needed: The current bidding window is between 3pm and 4pm)

1	Earlier Notification	ES6
2	Later Bidding Deadline	ES6
3	Either one is fine	ES6
88	Refused	ES6
99	Don't know	ES6

[If ES3 in (1-21)]

ES6. For how many of those [ES3] DBP events did your organization reduce their energy usage?

0-20	Key in Number	ES7a
21	More than 20	ES7a
22	Refused	ES8
23	Don't know	ES8

[IF Recall = 0 and (ES6 = 0 or (ES6< ES3 and ES3 in 1-21 and ES6 ne ES5)) then ask DR4B]

DR4B. Why didn't you take demand response actions for some of the DBP events?

[Probe for complete answer – i.e. if they say they weren't notified find out was it because the page didn't go through or because they didn't have their pager on them at the time?]

1	Operation was already was shut down	DR5
2	Don't need to take action to save money	DR5
3	Could not respond that fast	DR5
4	Not Available to Bid	DR5
5	Never planning to bid	DR5
6	Could not reduce load	DR5
7	Do not remember why	DR5
8	Was not a mandatory reduction	DR5
9	Doesn't make sense financially for us	DR5
77	<RECORD VERBATIM>	DR5
88	Refused	DR5
99	Don't Know	DR5

[IF Recall = 0 and ES6 in 1-21 then ask DR5]

DR5_DBP (formerly EV10). What type of demand reduction actions have you taken in response to 2005 DBP events?

1	Used backup generators	ES7a
2	Allowed the temperature to rise in the occupied space	ES7a
3	Reduced overhead lighting	ES7a
4	Reduced or shut off some or all production processes?	ES7a
5	Shut Down Completely	ES7a
6	Turned off non-critical equipment	ES7a
7	Shut Down Partially	ES7a
8	Rescheduled EMS	ES7a
77	<RECORD VERBATIM>	ES7a
88	Refused	ES7a
99	Don't Know	ES7a

[If ES5 in (1-21) and ES6 ne 0 then ask ES7a]

ES7a. Were there any DBP events during this past summer for which your organization placed a bid and then did not take any demand reduction actions?

1	Yes	ES7b
2	No	ES7c
88	Refused	ES7c
99	Don't know	ES7c

[If ES7a =1 or (ES5 in 1-21 and ES6 = 0) then ask ES7b]

ES7b. Why didn't your organization take any demand reduction actions after placing the bid?

77	Record Verbatim	ES7c
88	Refused	ES7c
99	Don't know	ES7c

If (ES6 in (1-21) then ask ES7c1]

ES7c1. Were there any DBP events during this past summer for which your organization took demand reduction actions despite not placing a bid?

1	Yes	ES7c2
2	No	DR23B
88	Refused	DR23B
99	Don't know	DR23B

[If ES7c1 =1 then ask ES7c2]

ES7c2. Why didn't your organization place a bid for these events?

1	Missed Bidding Window	DR23B
2	Could not meet bid minimum (50KW)	DR23B
3	Not worth the time given economic incentive level	DR23B
77	Record Verbatim	DR23B
88	Refused	DR23B
99	Don't know	DR23B

[If Recall = 0 or (recall = 1 and sc2 = 4) then ask DR23B]

DR23B (formerly DBP4A). What is the likelihood that you will take demand reduction actions for future DBP events? (Can select 1-5)

1	Very Likely	ES99
2	Somewhat Likely	ES99
3	Neither Likely nor unlikely	ES99
4	Somewhat unlikely	ES99
5	Not at all Likely	ES99
88	Refused	ES99
99	Don't Know	ES99

End DBP Battery

ES99. How likely is it that you would have taken peak load reduction actions this past summer if no financial incentives were offered? Would you say that you …

1	Definitely would NOT have taken peak load reductions	ES7d
2	Probably would NOT have taken peak load reductions	ES7d
3	Probably would have taken peak load reductions	ES7d
4	Definitely would have taken peak load reductions	ES7d
88	Refused	ES7d
99	Don't Know	ES7d

[If ES1 ne 0 and ES3 ne 0 then ask ES7d]

ES7d. Thinking back to all of the program events this summer, how critical did your organization feel these events were in helping [UTILITY] manage their power supply and/or avoid rolling blackouts. Did you feel they were …

1	Very Critical	ES8
2	Somewhat Critical	ES7e
3	Not at all Critical	ES7e
88	Refused	ES8
99	Don't know	ES8

[If ES7d in (2,3)]

ES7e. Would your organizations' response have been different if you felt the need was more critical?

1	Yes	ES7f
2	No	ES8
88	Refused	ES8
99	Don't know	ES8

[If ES7e =1]

ES7f. How would it have been different?

77	RECORD VERBATIM	DREVER_CPP
88	Refused	DREVER_CPP
99	Don't know	DREVER_CPP

[IF (ES2b = 0) and (CPP_fl = 1 and sc2 = 1 or sc2 in (3,4)) and ES7d in (1,88,99) or ES7e in (2,88,99)) then ask DREVER_CPP]

DREVER_CPP. Are there any circumstances under which your organization would consider taking demand reduction actions for future CPP events?

1	No	SIGNUP_CPP
77	Record Verbatim	DR25
88	Refused	DR25
99	Don't know	DR25

[If DREVER_CPP = 1 then ask SIGNUP_CPP]

SIGNUP_CPP. Given that your organization has not yet taken demand reduction actions for any CPP events and can't see circumstances under which they would, why did your organization signup for CPP?

77	Record Verbatim	DR25
88	Refused	DR25
99	Don't know	DR25

[IF (ES6 = 0) and (DBP_fl = 1 and sc2 = 1 or sc2 in (2,4)) and (ES7d in (1,88,99) or ES7e in (2,88,99)) then ask DREVER_DBP]

DREVER_DBP. Are there any circumstances under which your organization would consider taking demand reduction actions for future DBP events?

1	No	SIGNUP_DBP
77	Record Verbatim	DR25
88	Refused	DR25
99	Don't know	DR25

[If DREVER_DBP = 1 then ask SIGNUP_DBP]

SIGNUP_DBP. Given that your organization has not yet taken demand reduction actions for any DBP events and can't see circumstances under which they would, why did your organization signup for DBP?

77	Record Verbatim	DR25
88	Refused	DR25
99	Don't know	DR25

[If Recall = 0 and (CPP_FL = 1 and SC2=1) or SC2 in (3,4) then ask DR25]

DR25. Have you adjusted your summer load shape since signing up for the CPP program to take advantage of reduced on-peak and mid-peak prices or demand charges during non-CPP event hours?

1	Yes	ADJUST
2	No	ES8
88	Refused	ES8
99	Don't Know	ES8

[If DR25=1]

ADJUST. How did you adjust your load shape on non-critical peak days?

77	<RECORD VERBATIM>	ADJUST2
88	Refused	ADJUST2
99	Don't Know	ADJUST2

[If Recall = 0 and DR25 = 1 or Recall = 1 and DR25_old = 1 then ask Adjust2]

[If Recall = 1 and DR25_old = 1 then read:
"When we spoke with your organization in August the respondent indicated that your organization had adjusted your summer load shape since signing up for the CPP program to take advantage of reduced on-peak and mid-peak prices or demand charges during non-CPP event hours."

ADJUST2. Was this adjustment permanent or for the summer months only?

1	Permanent	ES8
2	CPP Event days only	ES8
77	Other <RECORD VERBATIM>	ES8
88	Refused	ES8
99	Don't Know	ES8

[ASK OF ALL]

ES8. How well prepared was your organization to manage the demand reductions called for by {UTILTY}'s Demand Response programs this summer? Would you say it was:

1	Very well prepared	DR9
2	Somewhat prepared	ES8A
3	Not at all prepared	ES8A
88	Refused	DR9
99	Don't know	DR9

[IF ES8 in (2,3) then ask ES8A]

ES8A. And why was that?

77	<RECORD VERBATIM>	DR9
88	Refused	DR9
99	Don't Know	DR9

[IF Recall = 0 and (ES6 in 1-21 or ES2B in 1-13) then ask DR9]

DR9 (formerly EV13). Did your organization experience any impacts in terms of personnel comfort or productivity as a result of your demand reduction actions? (Open end next)

1	Yes	IMPACT
2	No	RAMP
88	Refused	RAMP
99	Don't Know	RAMP

[If DR9 = 1 then ask IMPACT]

IMPACT. Please explain the impacts your organization experienced. (Do not Read)

1	Staff Complaints (lost hours, etc.)	RAMP
2	Warm/Uncomfortable Work Environment	RAMP
3	Lost Production	RAMP
4	Financial Impact	RAMP
5	Safety Concerns over limited lighting	RAMP
77	<RECORD VERBATIM>	RAMP
88	Refused	RAMP
99	Don't Know	RAMP

[ES2B in 1-13 or ES6 in 1-21 then ask RAMP]

RAMP. For the events for which you took demand reduction actions, how long did it take your organization to fully ramp up to your normal electrical consumption level after the event was over?

1	No time at all	DR15
2	Less than 10 minutes	DR15
3	10 to 20 minutes	DR15
4	20 to 30 minutes	DR15
5	30 minute to an hour	DR15
6	More than an hour	DR15
7	No ramp up required (e.g., facility closes)	DR15
77	Record Verbatim	DR15
88	Refused	DR15
99	Don't Know	DR15

[If Recall = 0 then ask DR15]

DR15. Do you have a plan detailing the demand reduction actions that your organization will take in response to [PROGRAM] events?

1	Yes	DR17
2	No	DR20
88	Refused	DR20
99	Don't Know	DR20

[If Recall = 0 and (ES2B in 1-13 or ES6 in 1-21) and (DR15 = 1) then ask DR17]

DR17. Does your load reduction plan differ from how your have responded to Demand Reduction events this summer?

1	Yes	DR20
2	No	DR20
88	Refused	DR20
99	Don't Know	DR20

TECHNICAL ASSISTANCE

Read "Now I have a few questions regarding the technical assistance services offered by [UTILITY]".

[If recall = 0 then ask DR20]

DR20. Did you take advantage of any utility assistance services to help your organization prepare for demand response events?

1	Yes	DR21
2	No	ASSIST
88	Refused	ASSIST
99	Don't Know	ASSIST

[If DR20 = 1 then ask DR21 and DR22]

DR21. What type of utility assistance did you utilize?

1	Technical Assistance	DR22
2	Participant Meetings/Seminars/Workshops	DR22
77	<RECORD VERBATIM>	DR22
88	Refused	DR22
99	Don't Know	DR22

DR22. Was the utility assistance useful in helping you fully respond to 2005 event notifications?

1	Yes	ASSIST
2	No	ASSIST
88	Refused	ASSIST
99	Don't Know	ASSIST

Ask of All

ASSIST. What type of utility assistance would your organization find most useful to help you take demand reduction actions for future [PROGRAM] events?

1	Lower Load Reduction Requirement	TA1
2	Provide more training	TA1
3	Increase Incentives	TA1
4	Notify Additional People	TA1
5	Nothing	TA1
77	<RECORD VERBATIM>	TA1
88	Refused	TA1
99	Don't Know	TA1

TA1. [UTILITY'S] Demand Response Technical Assistance and Incentives program has changed significantly since 2004. [UTILITY'S] 2005 Technical Assistance Incentive program provides customers with free on-site audits to help identify load reduction opportunities, as well as financial incentives to realize the load reduction opportunities identified. How familiar is your organization with [UTILITY'S] Technical Assistance and Incentive program?

1	Very familiar	TA2
2	Somewhat familiar	TA2
3	Not at all familiar	TA2
88	Refused	TA2
99	Don't Know	TA2

[If TA1 in (1,2) then ask TA2]

TA2. How likely are you to utilize the new Technical Assistance and Incentive program? Are you ..

1	Very Likely	ES13A
2	Somewhat Likely	ES13A
3	Neither Likely nor unlikely	ES13A
4	Somewhat unlikely	ES13A
5	Not at all Likely	ES13A
88	Refused	ES13A
99	Don't Know	ES13A

REASONS FOR PARTICIPATION

[If Recall = 0]

ES12A-ES12D. Next I would like to ask you a few general questions about your experience with the [PROGRAM} program and the reasons why your organization decided to participate. On a 1 to 5 scale, where 1 indicates insignificant and 5 indicates extremely significant, please indicate how significant each of the following reasons was to your organizations decision to participate in the [PROGRAM] program. [ROTATE RANDOMLY]

How significant a reasons is ….

ES12A.	Being a good corporate citizen	ES12F
ES12B.	Avoiding rolling blackouts	ES12F

ES12C.	The amount of potential bill savings	ES12F
ES12D.	Being able to participate in the program without significantly affecting your business operations.	ES12F
ES12E.	Receiving community recognition for your participation	ES12F

[IF ES12C in (3,4,5)]

ES12EE. You stated that the potential bill savings was important to your organizations decision to participate in the [PROGRAM] program. Have the financial incentives associated with the program met your expectations?

1	Yes	ES12F
2	Somewhat	ES12F
3	No	ES12F
88	Refused	ES12F
99	Don't Know	ES12F

[If ES12E=3]

ES12F. Why is that?

77	<RECORD VERBATIM>	ES12G
88	Refused	ES12G
99	Don't Know	ES12G

[IF ES12B in (3,4,5)]

ES12G. You just stated that avoiding rolling blackouts was important to your organization's decision to participate in the [PROGRAM] program. Do you feel that your participation ***is*** having a positive effect on [UTILITY]'s ability to maintain system reliability?

1	Yes	ES12H
2	Somewhat	ES12H
3	No	ES12H
88	Refused	ES12H
99	Don't Know	ES12H

[If ES12G=3]

ES12H. Why is that?

77	<RECORD VERBATIM>	EV15_CPP
88	Refused	EV15_CPP
99	Don't Know	EV15_CPP

[If Recall = 1]

ES12I. On a 1 to 5 scale, where 1 indicates insignificant and 5 indicates extremely significant, please indicate how significant receiving community recognition for your participation is to your organizations decision to participate in the [PROGRAM] program.

ES12E.	Receiving community recognition for your participation	CONCERN

CONCERN. What other concerns does your organization have about trying to temporarily reduce summer peak loads through participation in DR programs/tariffs?

77	<RECORD VERBATIM>	ES14A
88	Refused	ES14A
99	Don't know	ES14A

SATISFACTION RANKINGS

ES14A-ES14G. Now, based on your participation this summer, I would like you to rate your satisfaction with various aspects of the [PROGRAM] program. Please tell me if you were very satisfied, somewhat satisfied, somewhat dissatisfied, or very dissatisfied with each of the following:

ES14a.	The process by which you were notified about the DR event	
ES14b.	The amount of advanced notification	
ES14c1.	[If CPP_FL = 1 and SC2=1 or SC2 in (3,4)] The number of CPP events called	
ES14c2.	[If DBP_FL = 1 and SC2=1 or SC2 in (2,4)] The number of DBP events called	
ES14d1.	[If CPP_FL = 1 and SC2=1 or SC2 in (3,4)] The duration of the CPP events called	
ES14d2.	[If DBP_FL = 1 and SC2=1 or SC2 in (2,4)] The duration of the DBP events called	
ES14e.	The program-related customer service you received from your utility	
ES14f.	[If CPP_FL = 1 and SC2=1 or SC2 in (3,4)] The higher rates you paid for not reducing load	
ES14g1.	[If CPP_FL = 1 and SC2=1 or SC2 in (3,4)] The amount of the bill credit offered for participating in the CPP program	
ES14g2.	[If DBP_FL = 1 and SC2=1 or SC2 in (2,4)] The amount of incentives offered for participating in the DBP program	

OVERALL SATISFACTION AND FUTURE PARTICIPATION

Now I have a few questions about your organization's satisfaction with [UTILITY'S] [PROGRAM].

Start CPP Battery: [[If CPP_FL = 1 and SC2=1 or SC2 in (3,4)]]

ES15_CPP. Overall, how satisfied are you with your participation in the CPP program this past summer? (Next question is an open-end to capture why)

1	Very satisfied	ES16_CPP
2	Somewhat satisfied	ES16_CPP
3	Somewhat dissatisfied	ES16_CPP
4	Very dissatisfied	ES16_CPP
88	Refused	ES17_CPP
99	Don't Know	ES17_CPP

[If ES15_CPP in 1 to 4 then ask ES16_CPP]

ES16_CPP. Why is that?

77	<RECORD VERBATIM>	ES17_CPP
88	Refused	ES17_CPP
99	Don't know	ES17_CPP

ES17_CPP. Do you have any suggestions for improving the CPP program?

1	No Suggestions	ES20_DBP
77	<RECORD VERBATIM>	ES20_DBP
88	Refused	ES20_DBP
99	Don't know	ES20_DBP

Start DBP Battery:
[If DBP = 1 and SC2=1 or SC2 in (2,4)]

ES20_DBP. Overall, how satisfied are you with your participation in the DBP program this past summer? (Next question is an open-end for the why)

1	Very satisfied	ES21_DBP
2	Somewhat satisfied	ES21_DBP
3	Somewhat dissatisfied	ES21_DBP
4	Very dissatisfied	ES21_DBP
88	Refused	ES22_DBP
99	Don't Know	ES22_DBP

[If ES20_DBP in 1 to 4 then ask ES21_DBP]

ES21_DBP. And why do you say that?

77	<RECORD VERBATIM>	ES22_DBP
88	Refused	ES22_DBP
99	Don't know	ES22_DBP

ES22_DBP. Do you have any suggestions for improving the DBP program?

1	No Suggestions	ES31
77	<RECORD VERBATIM>	ES31
88	Refused	ES31
99	Don't know	ES31

ES31. [UTILITY} has a program called BIP, the Base Interruptible Program, and this program provides bill credits to customers who reduce their demand to a pre-determined level within 30 minutes of a BIP event being called. This program is different from the traditional interruptible programs. Is your organization familiar with the Base Interruptible Program (BIP)?

1	Very Familiar	ES32
2	Somewhat Familiar	ES32
3	Not at all Familiar	CA3a
4	Already Participating in BIP	ES32a
88	Refused	CA3a
99	Don't know	CA3a

ES32. Has your organization seriously consider, somewhat considered or not at all considered participating in the: Base Interruptible Program (BIP)?

1	Seriously Considered	ES32a
2	Somewhat Considered	ES32a
3	Have not Considered at all	ES32a
4	Already Participating in BIP	CA3a
88	Refused	CA3a
99	Don't know	CA3a

[If ES31 in 1,2 then ask ES32a]

ES32a. What do you like about the BIP Program?

1	<Record verbatim>	ES32b
88	Refused	ES32b
99	Don't know	ES32b

ES32b. What do you dislike about the BIP Program?

1	<Record verbatim>	CA3a
88	Refused	CA3a
99	Don't know	CA3a

DR CAPABILITIES

CA3a. At this facility, do you have the ability to view this facility's *hourly* demand on an in-house energy information system?

1	Yes	CA3b
2	No	CA3b
88	Refused	CA3b
99	Don't Know	CA3b

CA3b. Do you have the ability to view this facility's hourly demand on a [UTILITY] provided website?

1	Yes	FEED1
2	No	FEED1
88	Refused	FEED1
99	Don't Know	FEED1

[If recall = 0 and CA3b = 1 and (ES1 in 1-13 or ES3 in 1-21 or ES6 in 1-21) then ask FEED1-FEED5]

FEED1. Have you used the online tool to monitor your electricity usage before or during one of the 2005 events? (DO NOT READ- If needed you can tell participant name of the Online Tools: SDG&E = Quickview, SCE = SCE's Energy Manager Web site, PG&E = InterAct)

1	Yes	FEED2
2	No	FEED4
3	Don't Have Tool	FEED4
4	Don't know how to use tool	FEED3
88	Refused	FEED4
99	Don't Know	FEED4

[IF FEED1 = 1 then ask FEED2 and FEED3]

FEED2. Did the tool give you the information necessary to effectively manage your events?

1	Yes	FEED3
2	No	FEED3
88	Refused	FEED3
99	Don't Know	FEED3

[IF FEED1 = 1]

FEED3. How would you rate the ease of use of the online tool? Would you say it was …

1	Easy	FEED4
2	Somewhat Difficult	FEED4
3	Very Difficult	FEED4
88	Refused	FEED4
99	Don't Know	FEED4

[ASK OF ALL]
FEED4. Do you know if anyone else at your organization regularly logs onto the [UTILTY] website to view this facilities hourly demand?

1	Yes	FEED5
2	No	AT1
88	Refused	AT1
99	Don't Know	AT1

[If FEED4 = 1]

FEED5. What are the main reasons they use the online tool?

1	To monitor curtailment actions	AT1
2	To help place bids	AT1
3	To manage energy usage	AT1
77	Other	AT1
88	Refused	AT1
99	Don't Know	AT1

AUTOMATION TECHNOLOGY INVENTORY (FOR DRRC)

Read "Now I have a few questions about the equipment and controls capabilities at this facility. "

AT1. Does this facility have an Energy Management and Control System (EMCS) for centrally controlling some or all of the heating, ventilation, and air conditioning system or other equipment?

1	Yes	AT1c
2	No	AT2a
88	Refused	AT2a
99	Don't Know	AT2a

AT1c. Does your EMCS offer the ability to control all of the space temperatures on a "global" basis, that is, can it turn up or down all of the space temperature set points using a simple screen or other centralized action?

1	Yes	DR7
2	No	DR7
88	Refused	DR7
99	Don't Know	DR7

[If Recall = 0 and (ES2b in 1-13 or ES6 in 1-21) and AT1 = 1 then ask DR7]

DR7. Did your organization implement any [PROGRAM] load reductions through your EMCS?

1	Yes	DR8
2	No	DR8
88	Refused	DR8
99	Don't Know	DR8

[If Recall = 0 and (ES2b in 1-13 or ES6 in 1-21) then ask DR8]

DR8 (formerly EV10a). What level of automation was used to implement your organizations demand reduction actions? Were they….

1	Fully Automated	AT2a
2	Partially Automated	AT2a
3	Manual	AT2a
4	Does Not Apply (NOT READ)	AT2a
77	RECORD VERBATIM	AT2a
88	Refused	AT2a
99	Don't Know	AT2a

AT2a. Is your facility's space temperature control system primarily pneumatic, Direct Digital Control, or some of both?

1	Pneumatic	ES30
2	Direct Digital Control	ES30
3	Some of both	ES30
88	Refused	ES30

99	Don't Know	ES30

GENERAL MARKET KNOWLEDGE AND PERCEPTIONS

READ : Now I have a couple of questions for you about your organization's perceptions of California's electricity market over the next few years.

ES30. As a result of your experience with the [PROGRAM] program(s) this past summer, would you say you are: much more knowledgeable, somewhat more knowledgeable, or no more knowledgeable about managing your energy usage at times of peak demand?

1	Much more knowledgeable	EM4
2	Somewhat more knowledgeable	EM4
3	No more knowledgeable	EM4
88	Refused	EM4
99	Don't know	EM4

EM4. And over the next three years, does your organization expect wholesale electricity prices to increase, decrease, or stay about the same?

1	Increase	EM5
2	Decrease	EM5
3	Stay about the same	EM5
88	Refused	EM5
99	Don't know	EM5

EM5. In your organization's view, how likely is it that California's power supplies will be inadequate to meet expected power demand over the next three years? Would you say…

1	Very Likely	EE1
2	Somewhat Likely	EE1
3	Somewhat Unlikely	EE1
4	Very Unlikely	EE1
88	Refused	EE1
99	Don't know	EE1

EE1. Has your organization participated in any other energy efficiency programs that reduce your overall energy usage or shift your load from peak to off-peak periods in the past two years?

1	Standard Performance Contracting (SPC)	EC1
2	Express Efficiency Rebates	EC1
3	Energy Efficiency Audits	EC1
77	Record Verbatim	EC1
88	Refused	EC1
99	Don't know	EC1

FIRMOGRAPHIC CHARACTERISTICS

Now I'd like to ask a few quick questions about this facility. Unless otherwise stated, all questions pertain to THIS FACILITY [RESTATE FACILITY LOCATION IF NECESSARY].

EC1. What is the main activity performed at this location?

1	Office	EC2
2	Retail (non-food)	EC2

3	College/university	EC2
4	School	EC2
5	Grocery store	EC2
6	Convenience store	EC2
7	Restaurant	EC2
8	Health care/hospital	EC2
9	Hotel or motel	EC2
10	Warehouse	EC2
11	Personal Service	EC2
12	Community Service/Church/Temple/Municipality	EC2
13	Industrial Electronic & Machinery	EC2
14	Industrial Mining, Metals, Stone, Glass, Concrete	EC2
15	Industrial Petroleum, Plastic, Rubber and Chemicals	EC2
16	Other Industrial	EC2
17	Agricultural	EC2
18	Transportation/Telecommunications/Utility	EC2
77	Other (SPECIFY)	EC2
88	Refused	EC2
99	Don't know	EC2

EC2. Approximately how many square feet does your organization occupy in this facility?

1	Less than 10,000 square feet	EC3
2	10,000 but less than 20,000 square feet	EC3
3	20,000 but less than 50,000 square feet	EC3
4	50,000 but less than 100,000 square feet	EC3
5	100,000 but less than 200,000 square feet	EC3
6	200,000 but less than 300,000 square feet	EC3
7	300,000 but less than 400,000 square feet	EC3
8	400,000 but less than 500,000 square feet	EC3
9	Over 500,000 square feet	EC3
10	Ag/Non-facility – Outdoors	EC3
88	Refused	EC3

EC3. Does your organization.....

1	Own this space	EC5
2	Lease this space	EC5
3	Own a portion and lease the remainder	EC5
88	Refused	EC5
99	Don't know	EC5

EC5. What percent of your organization's total annual operating costs do energy costs represent?

1	Less than 1 percent	EC7
2	1 to 4 percent	EC7
3	5 to 10 percent	EC7
4	11 to 25 percent	EC7
5	Over 25	EC7
88	Refused	EC7
99	Don't know	EC7

EC7. What is the approximate number of full-time equivalent workers of all types employed by your organization at this facility?

1	1 to 10	EC9A
2	11 to 50	EC9A

3	51 to 100	EC9A
4	100 to 250	EC9A
5	251 to 500	EC9A
7	501 to 1000	EC9A
8	Or, over 1000	EC9A
88	[Don't read] Refused	EC9A
99	[Don't read] Don't know	EC9A

EC9A. Which of the following is the LARGEST end use in terms of electricity consumption for this facility?

EC9a	First Largest	EC9B
1	Lighting	EC9B
2	HVAC	EC9B
3	Continuous processing	EC9B
4	Batch processing	EC9B
5	Refrigeration	EC9B
6	Other, Specify______________	EC9B
88	Refused	EC9B
99	Don't know	EC9B

EC9B. And which would you say used the SECOND most electricity?

EC9b	First Largest	EC10
1	Lighting	EC10
2	HVAC	EC10
3	Continuous processing	EC10
4	Batch processing	EC10
5	Refrigeration	EC10
6	Other, Specify______________	EC10
88	Refused	EC10
99	Don't know	EC10

EC10. Does this location have any on-site electricity generators?

1	Yes, for backup/standby purposes only	EC10a
2	Yes, as an everyday supplement or replacement for electricity purchases from the grid	EC10a
3	No	CL1
88	Refused	CL1
99	Don't know	CL1

[IF EC10 = 1 or 2, ELSE SKIP TO CL1]

EC10a. What percent of this location's electricity load can be met by your on-site generation?

______ Percent (allow > 100%)

EC10b. Are their legal restrictions on the number of hours your on-site system can run during the summer?

1	Yes	CL1
2	No	CL1
88	Refused	CL1
99	Don't know/	CL1

CLOSE

READ: And finally, …

CL1. Do you have any final comments or input regarding your experiences with the demand response programs or events?

1	No Comments	
77	<RECORD VERBATIM>	
88	Refused	
99	Don't Know	

Those are all the questions I have for you today. Thank you very much for your time.

B4. 2005 Traditional Interruptible Customer Survey Instrument

2005 Traditional Interruptible Customer Survey Instrument

VARIABLES:

If UTILITY = PG&E, then
PROGRAM = "Schedule 19/20 Non-Firm"
SOFTWARE = "InterAct II"
RULES = "30 events per year, 6 hours maximum per event, and no more than 100 total hours per year"

If UTILITY = SCE, then
PROGRAM = "I-6"
SOFTWARE = "EnergyManager"
RULES = "25 events per year, 6 hours maximum per event, and no more than 150 total hours per year"

If UTILITY = SDG&E, then
PROGRAM = "AL TOU CP"
SOFTWARE = "kWickview"
RULES = "120 total hours per year and 6 hours maximum per event."

INTRODUCTION

Screening, general introduction, and confirmation of participation status

PROGRAM SATISFACTION

PS1. How long have you been participating in the [PROGRAM] program? (DO NOT PROMPT)

1	1 year	PS2
2	2 years	PS2
3	3 years	PS2
4	4 years	PS2
5	5 years	PS2
6	6 years	PS2
7	7 years	PS2
8	8 years	PS2
9	9 years	PS2
10	10 years	PS2
11	More than 10 years	PS2
88	Refused	PS2
99	Don't Know	PS2

PS2. What was the primary reason for signing up for the [PROGRAM] program? (DO NOT PROMPT)

1	Save money on energy costs/bills	PS3
2	Being able to participate without significantly affecting business operations	PS3
3	Being a good corporate citizen	PS3
4	Avoiding rolling blackouts	PS3
5	Receiving community recognition for organization's participation	PS3

77	Other (specify)	PS3
88	Refused	PS3
99	Don't Know	PS3

PS3. Now, based on your participation to date, I would like you to rate your satisfaction with various aspects of the [PROGRAM] program. Please tell me if you were very satisfied, somewhat satisfied, somewhat dissatisfied, or very dissatisfied with each of the following:

PS3a. The enrollment process [IF UTILITY = PG&E or SCE: "and determination of your firm service level"]

1	Very satisfied	PS3b
2	Somewhat satisfied	PS3b
3	Somewhat dissatisfied	PS3b
4	Very dissatisfied	PS3b
88	Refused	PS3b
99	Don't Know	PS3b

PS3b. The notification process for [IF UTILITY = PG&E or SCE: "interruption events"; ELSE IF SDG&E: "critical price periods"]

1	Very satisfied	PS3c
2	Somewhat satisfied	PS3c
3	Somewhat dissatisfied	PS3c
4	Very dissatisfied	PS3c
88	Refused	PS3c
99	Don't Know	PS3c

PS3c. The frequency of [IF UTILITY = PG&E or SCE: "interruption events"; ELSE IF SDG&E: "critical price periods"]

1	Very satisfied	PS3d
2	Somewhat satisfied	PS3d
3	Somewhat dissatisfied	PS3d
4	Very dissatisfied	PS3d
88	Refused	PS3d
99	Don't Know	PS3d

PS3d. The duration of [IF UTILITY = PG&E or SCE: "interruption events"; ELSE IF SDG&E: "critical price periods"]

1	Very satisfied	PS3e
2	Somewhat satisfied	PS3e
3	Somewhat dissatisfied	PS3e
4	Very dissatisfied	PS3e
88	Refused	PS3e
99	Don't Know	PS3e

PS3e. The reduced overall energy and demand charges for participation

1	Very satisfied	PS3f
2	Somewhat satisfied	PS3f
3	Somewhat dissatisfied	PS3f

4	Very dissatisfied	PS3f
88	Refused	PS3f
99	Don't Know	PS3f

PS3f. The level of [IF UTILITY = PG&E or SCE: "penalties for failure to curtail during interruption events"; ELSE IF SDG&E: "critical peak prices"]

1	Very satisfied	PS3g
2	Somewhat satisfied	PS3g
3	Somewhat dissatisfied	PS3g
4	Very dissatisfied	PS3g
88	Refused	PS3g
99	Don't Know	PS3g

PS3g. The [SOFTWARE] load management software available from [UTILITY]

1	Very satisfied	PS3h
2	Somewhat satisfied	PS3h
3	Somewhat dissatisfied	PS3h
4	Very dissatisfied	PS3h
88	Refused	PS3h
99	Don't Know	PS3h

PS4. Overall, how satisfied are you with your participation in this program?

1	Very satisfied	PS5
2	Somewhat satisfied	PS5
3	Somewhat dissatisfied	PS4a
4	Very dissatisfied	PS4a
88	Refused	PS5
99	Don't Know	PS5

[IF PS4 = 3 or 4, then ask PS4; ELSE SKIP TO PS5]

PS4a. Could you briefly summarize why your experience with the [PROGRAM] program has been unsatisfactory?

77	Record verbatim	PS5
88	Refused	PS5
99	Don't Know	PS5

[IF UTILITY = PG&E or SCE, then ask PS5; ELSE SKIP TO EX1]

PS5. Have you re-designated your firm service level since you originally enrolled in this program?

1	Yes	PS5a
2	No	EX1
88	Refused	EX1
99	Don't Know	EX1

[IF PS5 = 1, then ask PS5a; ELSE SKIP TO EX1]

PS5a. Approximately what year did you do this?

77	Record year	PS5b
88	Refused	PS5b
99	Don't Know	PS5b

PS5b. Did you increase or decrease your firm service level?

1	Increase	PS5c
2	Decrease	PS5c
88	Refused	PS5c
99	Don't Know	PS5c

PS5c. Could you briefly summarize why you re-designated your firm service level? (DO NOT PROMPT)

1	Previous curtailment commitments were too much	EX1
2	Required by contract because summer peak demand fell	EX1
77	Other (specify)	EX1
88	Refused	EX1
99	Don't Know	EX1

2005 EVENT EXPERIENCE

EX1. How often [IF UTILITY = PG&E or SCE: "was your organization called upon to curtail in 2005, not including test events"; ELSE IF SDG&E: "did you experience critical peak prices in 2005"]? (DO NOT PROMPT)

77	Record number	EX2
88	Refused	EX2
99	Don't Know	EX2

EX2. Does your organization have a pre-established curtailment strategy?

1	Yes	EX3
2	No	EX3
88	Refused	EX3
99	Don't Know	EX3

EX3. What specific actions do you take to reduce load during curtailment event(s)? (READ LIST - MULTIPLE ANSWERS OK)

1	Turn off/reduced overhead lighting	EX3a
2	Turn off computers and other office equipment	EX3a
3	Reduce thermostat temperature setting	EX3a
4	Shut down some or all production processes	EX3a
5	Shift production to other day or period	EX3a
6	Shut down some or all refrigeration/cold storage	EX3a
7	Run back-up generators	EX3a
77	Other action (specify)	EX3a
88	Refused	EX3a
99	Don't Know	EX3a

EX3a. What is your best guess of the costs of each of these actions to your organization, either per hour or per event?

1	(Answer given in $/hour)	EX3b
2	(Answer given in $/event)	EX3c
88	Refused	EX4
99	Don't Know	EX4

EX3b. (ENTER $/HOUR VALUE)

77	Record number	EX4

EX3c. (ENTER $/EVENT VALUE)

77	Record number	EX4

EX4. To what extent are these load reductions centrally controlled, as opposed to being a diffuse set of manual actions? Would you say these load reductions are…

1	Entirely centrally controlled	EX5
2	Partially centrally controlled	EX5
3	Not at all centrally controlled	EX5
88	Refused	EX5
99	Don't Know	EX5

EX5. Have you used the [SOFTWARE] software available from [UTILITY] to help plan or manage your load reductions?

1	Yes	EX5a
2	No	EX6
88	Refused	EX6
99	Don't Know	EX6

[IF EX5 = 1, then ask EX5a; ELSE SKIP TO EX6]

EX5a. How useful has the [SOFTWARE] software provided by [UTILITY] been in managing or planning your load reductions? Would you say…

1	Very helpful	EX5b
2	Somewhat helpful	EX5b
3	Not at all helpful	EX6
4	Never used it	EX6
88	Refused	EX6
99	Don't Know	EX6

[IF EX5a = 1 or 2, then ask EX5b; ELSE SKIP TO EX6]

EX5b. What aspects of the [SOFTWARE] software have been the most useful in managing or planning your load reductions?

77	Record verbatim	EX6
88	Refused	EX6
99	Don't Know	EX6

EX6. Would you say that it is generally easy or difficult for your organization to curtail the amount of load required in the required timeframe? Would you say:

1	Very easy	EX6a
2	Somewhat easy	EX6a
3	Somewhat difficult	EX6a
4	Very difficult	EX6a
88	Refused	NM1
99	Don't Know	NM1

[IF EX6 = 1, 2, 3, or 4, then ask EX6a; ELSE SKIP TO NM1]

EX6a. Briefly, what is the main reason why your organization has found it [ANSWER TO EX6] to curtail in the required timeframe?

77	Record verbatim	NM1
88	Refused	NM1
99	Don't Know	NM1

NOTIFICATON TECHNOLOGY

NM1. What type of event notification systems does this facility use for the [PROGRAM] program? (DO NOT PROMPT – MULTIPLE ANSWERS OK)

1	Remote terminal unit (RTU)	AT1
2	Two-way paging	AT1
3	Email or interactive website	AT1
4	Fax	AT1
5	Telephone	AT1
77	Other (specify)	AT1
88	Refused	AT1
99	Don't Know	AT1

AUTOMATION TECHNOLOGY

Now I have a few questions about the equipment and controls capabilities at this facility.

AT1. Does this facility have an Energy Management and Control System (EMCS) for centrally controlling some or all of the heating, ventilation, and air conditioning system or other equipment?

1	Yes	AT1a
2	No	AT2
88	Refused	AT2
99	Don't Know	AT2

[IF AT1 = 1, then ask AT1a; ELSE SKIP TO AT2]

AT1a. And which of the following systems does your EMCS control?

1	Rooftop or other distributed HVAC units	AT1b
2	Central cooling plant	AT1b
3	Major ventilation fans	AT1b
4	Zone temperature	AT1b

5	Lighting equipment	AT2
6	Production processes	AT2
77	Other (specify_____)	AT2
88	Refused	AT2
99	Don't Know	AT2

[IF AT1a = 1, 2, 3, or 4, then ask AT1b; ELSE SKIP TO AT2]

AT1b. Does your EMCS offer the ability to control all of the space temperatures on an individual zone basis, that is, can it turn up or down each of the temperature set points individually?

1	Yes	AT1c
2	No	AT1c
88	Refused	AT1c
99	Don't Know	AT1c

AT1c. Does your EMCS offer the ability to control all of the space temperatures on a "global" basis, that is, can it turn up or down all of the space temperature set points using a simple screen or other centralized action?

1	Yes	AT2
2	No	AT2
88	Refused	AT2
99	Don't Know	AT2

AT2. What type of HVAC equipment controls the temperature of the occupied space(s) at your facility?

1	VAV boxes	AT2a
2	Constant volume mixing boxes	AT2a
77	Other (specify_____)	AT2a
88	Refused	AT2a
99	Don't Know	AT2a

AT2a. Is your facility's space temperature control system primarily pneumatic, direct digital control, or some of both?

1	Pneumatic	EA8
2	Direct digital controls	EA8
3	Some of both	EA8
88	Refused	EA8
99	Don't Know	EA8

AUTOMATION INVESTMENTS

EA8. In the past 2 years, has your organization considered any automation investments in order to improve your ability to manage energy use at this facility?

1	Yes	EA9
2	No	F2a
88	Refused	F2a
99	Don't Know	F2a

[IF EA8 = 1, then ask EA9; ELSE SKIP TO F2a]

EA9. What are the reasons why your organization considered these upgrades to your control systems? (DO NOT PROMPT - MULTIPLE ANSWERS OK)

1	Save on energy costs	EA10
2	Upgrade old equipment	EA10
3	Increase flexibility of controls systems	EA10
4	Be able to respond to dynamic pricing	EA10
5	To increase occupant comfort	EA10
77	Other (specify_____)	EA10
88	Refused	EA10
99	Don't know	EA10

EA10. Did you actually install any of these control system upgrades for your business?

1	Yes	EA11
2	No	F2a
88	Refused	F2a
99	Don't Know	F2a

[IF EA10 = 1, then ask EA11; ELSE SKIP TO F2a]

EA11. And which upgrades did you choose to install? (DO NOT PROMPT - MULTIPLE ANSWERS OK)

1	Controls or EMCS	F2a
2	Variable frequency drives	F2a
3	Programmable thermostat	F2a
4	Sensors or motion detectors	F2a
77	Other (specify_____)	F2a
88	Refused	F2a
99	Don't Know	F2a

DR PROGRAM AWARENESS & FAMILIARITY

F2a. How familiar is your organization with [UTILITY'S] voluntary *Critical Peak Pricing* (CPP) tariff? Would you say…

1	Very familiar	F2b
2	Somewhat familiar	F2b
3	Not at all familiar	F2b
88	Refused	F2b
99	Don't Know	F2b

F2b. How familiar is your organization with [UTILITY'S] *Demand Bidding Program* (DBP)?

1	Very familiar	F2d
2	Somewhat familiar	F2d
3	Not at all familiar	F2d
88	Refused	F2d
99	Don't Know	F2d

F2d. How familiar is your organization with the *California Demand Reserves Partnership* (Cal-DRP) program?

1	Very familiar	F2e
2	Somewhat familiar	F2e
3	Not at all familiar	F2e
88	Refused	F2e
99	Don't Know	F2e

F2e. How familiar is your organization with [UTILITY'S] *Base Interruptible Program* (BIP)?

1	Very familiar	GF1
2	Somewhat familiar	GF1
3	Not at all familiar	GF1
88	Refused	GF1
99	Don't Know	GF1

OUTLOOK GOING FORWARD

GF1. Do you anticipate remaining in the [PROGRAM] program next summer?

1	Yes	GF2
2	No	GF1a
88	Refused	GF2
99	Don't Know	GF2

[IF GF1 = 2, then ask GF1a; ELSE SKIP TO GF2]

GF1a. What other rate or program would you be most likely to consider? (DO NOT PROMPT - MULTIPLE ANSWERS OK)

1	Critical Peak Pricing (CPP)	GF1b
2	Demand Bidding (DBP)	GF1b
3	Base Interruptible Program (BIP)	GF1b
4	OBMC	GF1b
5	Scheduled Load Reduction Program (SLRP)	GF1b
6	Rolling Blackout Reduction Program (RBRP)	GF1b
77	Other (specify)	GF1b
88	Refused	GF3
99	Don't Know	GF3

[IF GF1a = 1, 2, 3, 4, 5, or 6, then ask GF1b; ELSE SKIP TO GF3]

GF1b. Which features of [PROGRAMS CITED IN GF1a] are most attractive to your organization? (DO NOT PROMPT - MULTIPLE ANSWERS OK)

1	Pricing/incentives	GF3
2	Penalty levels or structure	GF3
3	Event notification	GF3
4	Event frequency	GF3
5	Event duration	GF3
6	Length of settlement process	GF3

7	Reliability of supply	GF3
77	Other (specify)	GF3
88	Refused	GF3
99	Don't Know	GF3

GF2. In the last two years, have you considered switching to another rate or participating in demand response programs?

1	Yes	GF2a
2	No	GF3
88	Refused	GF3
99	Don't Know	GF3

[IF GF2 = 1, then ask GF2a; ELSE SKIP TO GF3]

GF2a. If yes, which programs appealed to you? (DO NOT PROMPT - MULTIPLE ANSWERS OK)

1	Critical Peak Pricing (CPP)	GF2b
2	Demand Bidding (DBP)	GF2b
3	Base Interruptible Program (BIP)	GF2b
4	OBMC	GF2b
5	Scheduled Load Reduction Program (SLRP)	GF2b
6	Rolling Blackout Reduction Program (RBRP)	GF2b
77	Other (specify)	GF2b
88	Refused	GF2b
99	Don't Know	GF2b

GF2b. Which features of this program are most attractive to your organization? (DO NOT PROMPT - MULTIPLE ANSWERS OK)

1	Pricing/incentives	GF2c
2	Penalty levels or structure	GF2c
3	Event notification	GF2c
4	Event frequency	GF2c
5	Event duration	GF2c
6	Length of settlement process	GF2c
7	Reliability of supply	GF2c
77	Other (specify)	GF2c
88	Refused	GF2c
99	Don't Know	GF2c

GF2c. Which features did you **not** like about the programs you considered? (DO NOT PROMPT - MULTIPLE ANSWERS OK)

1	Pricing/incentives	GF3
2	Penalty levels or structure	GF3
3	Event notification	GF3
4	Event frequency	GF3
5	Event duration	GF3
6	Length of settlement process	GF3
7	Reliability of supply	GF3
8	Program complexity	GF3
88	Refused	GF3

99	Don't Know	GF3

GF3. Are you aware of the Technical Assistance Incentive Program to help customers identify demand response load reduction opportunities within their facility and help offset the costs of implementing those opportunities?

1	Yes	GF3a
2	No	GF4
88	Refused	GF4
99	Don't Know	GF4

[IF GF3 = 1, then ask GF3a; ELSE SKIP TO GF4]

GF3a. Are you planning to enroll in the Technical Assistance Incentive Program?

1	Yes	GF3a
2	No	GF4
88	Refused	GF4
99	Don't Know	GF4

[IF GF3a = 1, then ask GF3b; ELSE SKIP TO GF4]

GF3b. Which aspects of the Technical Assistance Incentive Program are you planning to use? (DO NOT PROMPT - MULTIPLE ANSWERS OK)

1	Preliminary audit	GF3a
2	Detailed technical audit	GF4
3	Financial incentives to install demand response measures	GF4
88	Refused	GF4
99	Don't Know	GF4

GF4. Under the terms of service for [PROGRAM] customers, [IF UTILITY = PG&E or SCE: "service interruptions"; ELSE IF SDG&E: "critical price periods"] are limited to a maximum of [RULES]. In a worst-case scenario where the maximum number of [IF UTILITY = PG&E or SCE: "interruptions"; ELSE IF SDG&E: "critical price periods"] was required to avoid system emergencies, how likely is it that your organization would remain in the [PROGRAM] program?

1	Very likely	GF5
2	Somewhat likely	GF5
3	Somewhat unlikely	GF4a
4	Very unlikely	GF4a
88	Refused	GF5
99	Don't Know	GF5

[IF GF4 = 3 or 4, then ask GF4a; ELSE SKIP TO GF5]

GF4a. What is the upper limit on the number of [IF UTILITY = PG&E or SCE: "service interruptions"; ELSE IF SDG&E: "critical price periods"] that your organization could withstand in a worst-case scenario before considering leaving the [PROGRAM] program?

77	Record verbatim	GF4b
88	Refused	GF5
99	Don't Know	GF5

[IF GF4a = 77, then ask GF4b; ELSE SKIP TO GF5]

GF4b. If these upper limits actually occurred, which of the following actions are you most likely to take? (READ LIST)

1	Go to a firm service rate	GF5
2	Go to a firm service rate and consider participating in demand response programs	GF5
3	Go to another non-firm service rate	GF5
4	Go to another non-firm service rate and consider participating in demand response programs	GF5
77	Other (specify)	GF5
88	Refused	GF5
99	Don't Know	GF5

GF5. If the [PROGRAM] program were discontinued, which of the following actions would are you most likely to take? (READ LIST)

1	Go to a firm service rate	EC1
2	Go to a firm service rate and consider participating in demand response programs	EC1
3	Go to another non-firm service rate	EC1
4	Go to another non-firm service rate and consider participating in demand response programs	EC1
77	Other (specify)	EC1
88	Refused	EC1
99	Don't Know	EC1

FIRMOGRAPHIC CHARACTERISTICS

Now I'd like to ask a few quick questions about this facility. Unless otherwise stated, all questions pertain to [THIS FACILITY]. (RESTATE FACILITY LOCATION IF NECESSARY)

EC1. What is the main activity performed at this location?

1	Office	EC2
2	Retail (non-food)	EC2
3	College/university	EC2
4	School	EC2
5	Grocery store	EC2
6	Convenience store	EC2
7	Restaurant	EC2
8	Health care/hospital	EC2
9	Hotel or motel	EC2
10	Warehouse	EC2
11	Personal Service	EC2
12	Community Service/Church/Temple/Municipality	EC2
13	Industrial Electronic & Machinery	EC2
14	Industrial Mining, Metals, Stone, Glass, Concrete	EC2
15	Industrial Petroleum, Plastic, Rubber and Chemicals	EC2
16	Other Industrial	EC2
17	Agricultural	EC2

18	Transportation/Telecommunications/Utility	EC2
77	Other (SPECIFY)	EC2
88	Refused	EC2
99	Don't know	EC2

EC2. Approximately how many square feet does your organization occupy in this facility?

1	Less than 10,000 square feet	EC3
2	10,000 but less than 20,000 square feet	EC3
3	20,000 but less than 50,000 square feet	EC3
4	50,000 but less than 100,000 square feet	EC3
5	100,000 but less than 200,000 square feet	EC3
6	200,000 but less than 300,000 square feet	EC3
7	300,000 but less than 400,000 square feet	EC3
8	400,000 but less than 500,000 square feet	EC3
9	Over 500,000 square feet	EC3
10	Ag/Non-facility – Outdoors	EC3
88	Refused	EC3
99	Don't know	EC3

EC3. Does your organization...

1	Own this space	EC5
2	Lease this space	EC5
3	Own a portion and lease the remainder	EC5
88	Refused	EC5
99	Don't know	EC5

EC5. What percent of your organization's total annual operating costs do energy costs represent?

1	Less than 1 percent	EC5A
2	1 to 4 percent	EC5A
3	5 to 10 percent	EC5A
4	11 to 25 percent	EC5A
5	Over 25	EC5A
88	Refused	EC5A
99	Don't know	EC5A

EC5A. Has your organization assigned responsibility for controlling energy usage and costs to any of the following?

1	An in-house staff person	EC6
2	A group of staff	EC6
3	An outside contractor	EC6
4	No one	EC6
88	Refused	EC6
99	Don't know	EC6

EC6. Approximately how many locations does your organization have in California?

1	1	EC7
2	2 to 4	EC7
3	5 to 10	EC7

4	11 to 25	EC7
5	Over 25	EC7
88	Refused	EC7
99	Don't know	EC7

EC7. What is the approximate number of full-time equivalent workers of all types employed by your organization at this facility?

1	1 to 10	EC9A
2	11 to 50	EC9A
3	51 to 100	EC9A
4	100 to 250	EC9A
5	251 to 500	EC9A
7	501 to 1000	EC9A
8	Or, over 1000	EC9A
88	[Don't read] Refused	EC9A
99	[Don't read] Don't know	EC9A

EC9A. Which of the following is the LARGEST end use in terms of electricity consumption for this facility?

1	Lighting	EC9B
2	HVAC	EC9B
3	Continuous processing	EC9B
4	Batch processing	EC9B
5	Refrigeration	EC9B
77	Other, Specify______________	EC9B
88	Refused	EC9B
99	Don't know	EC9B

EC9B. And which would you say used the SECOND most electricity?

1	Lighting	EC10
2	HVAC	EC10
3	Continuous processing	EC10
4	Batch processing	EC10
5	Refrigeration	EC10
77	Other, Specify______________	EC10
88	Refused	EC10
99	Don't know	EC10

EC10. Does this location have any on-site electricity generators?

1	Yes, for backup/standby purposes only	EC10a
2	Yes, as an everyday supplement or replacement for electricity purchases from the grid	EC10a
3	No	CL1
88	Refused	CL1
99	Don't know	CL1

[IF EC10 = 1 or 2, then EC10a; ELSE SKIP TO CL1]

EC10a. What percent of this location's electricity load can be met by your on-site generation?

______ Percent (allow > 100%)

EC10b. Are their legal restrictions on the number of hours your on-site system can run during the summer?

1	Yes	CL1
2	No	CL1
88	Refused	CL1
99	Don't know	CL1

CLOSE

CL1. Do you have any final comments or suggestions about demand response programs being offered by [UTILITY]?

<VERBATIM>

B5. 2005 BIP-Eligible Customer Interview Guide

BIP Potential In-Depth Interview Guide

Hi, this is _______, I'm calling on behalf of the [UTILITY] and the California Public Utilities Commission from Quantum Consulting/Summit Blue Consulting.

We are talking to selected businesses and organizations to learn about their demand response program and rate preferences. The Public Utilities Commission wants to better understand how businesses think about and manage their peak energy usage and how they perceive various rates and programs. Your input is very important to the Commission. May I speak with _________________ (or: the person in your organization who is responsible for energy-related decisions for this facility)?

The information you provide will be kept in strictest confidence, and will be shared with the study team (the Energy Commission and its contractors, and [UTILITY]) only in a form that does not allow the identification of any business, individual or facility.

If utility contact information requested, please use the following:

SCE:	Edward Lovelace	(626) 302-1697
PG&E:	Susan McNicoll	(415) 973-7404
SDG&E:	Kevin McKinley	(858) 654-1142

<u>I. Program Experience:</u> I would like to start by asking about your organization's experience with interruptible rates.

1. Are you currently on a traditional interruptible rate [such AL TOU CP, I-6 or Schedule 19/20 Non-Firm]?
    a. If YES, which one?
        - When did you begin participating?
        - What do you see as the key advantages of this rate/program?
        - What do you see as its key disadvantages? GO TO Q1d
    b. If NO, have your ever participated in an interruptible rate? IF NO, GO TO Q1d
    c. If you have participated:
        - What rate?
        - When and how long were you on this rate?
        - Why did you drop out ?(probe for length and frequency of events, financial issues, business/operational concerns, ask about energy crisis if appropriate) GO TO Q1d
    d. Are you currently enrolled in a demand response program such as DBP, CPP, Cal-DRP, or 20-20? IF NO, IR PARTS GO TO Q2, OTHERS TO Q5
        - What program?
        - What do you see as the key advantages of this program?

- What do you see as its key disadvantages? IR PARTS GO TO Q2, OTHERS GO TO Q5

II. Alternatives to current rate (Participants only):

2. If the interruptible rate you are on were discontinued, which of the following actions would you be most likely to take:

    a. Go to a firm rate and stay there regardless of other available interruptible or demand response rates,
    b. Go to a firm rate and consider the various demand-response and interruptible rate and program alternatives, or
    c. Move directly to another interruptible or demand-response rate or program.

3. What are the main reasons for your likely choice? (probe for prices/incentives; penalties; conditions of curtailment; length of settlement process; uncertainty)

4. If you were to move to another interruptible or demand-response program, what other rate or program would you be most likely to consider? For what reasons?

III. BIP Awareness (All): One of the rates currently being offered by (UTILITY) as an alternative to traditional interruptible rates is the Base Interruptible Program, or BIP.

5. How familiar are you with the features of the Base Interruptible Program? Would you say you are 1) not at all familiar, 2) somewhat familiar, or 3) very familiar with the Base Interruptible Program? IF FAMILIAR, GO TO Q6; IF NOT, GO TO Q7 (If description requested: We will go over the details of the rate in just a minute and get your reaction to specific aspects of the program. THEN PROCEED AS IF NOT FAMILIAR AND GO TO Q7.)

6. If familiar with BIP: Have you investigated or considered signing up for BIP? (IF NO, GO TO Q7)
    a. If so, what has been your source of information about BIP?
    b. Have you received or seen what you think is enough program information on BIP to decide whether to sign up for BIP or not? IF YES, GO TO Q8; IF NO, ASK 6c, THEN GO TO Q7.
    c. What additional information would you find most useful in making your decision?

IV. FOR THOSE NOT ANSWERING Q3 AND Q4: BIP Rate Analysis:

7. Next I would like to describe the key features of the BIP program and get your reaction to/interest in a program or rate with these features.
    a. Eligible customer must have a maximum demand of at least 200 kW and be able to curtail or shift the greater of 100 kW or 15% of their total peak load,

based on the difference between the maximum uncontrolled load and a "firm service level" to which the customer agrees to reduce when events are called.

b. BIP provides a $7/kW credit each month throughout the year for the load that would be curtailed or shifted off peak.
c. BIP has a cap of 1 event per day up 4 hours duration, a maximum of 10 events per month, and no more than 120 hours total in a given year.
d. If the firm service level is not fully reached during an event, the amount of energy used above the firm service demand level would be penalized at a rate of about $10/kWh ($6 for PG&E and SDG&E).
e. So the credit is $700 per hundred kW, and the penalty is $1000 per hundred kWh if the FSL isn't reached when an event is called ($600 per hundred kWh for PG&E and SDG&E). Does that sound clear to you? If not, I can provide a numerical example: *As an example, let's use a 700 kW size customer who plans to curtail or shift 200 kW of load to get down to a Firm Service Level of 500 kW. The BIP credit for that 200 kW of impact would be $7 x 200 kW x 12 months, or $16,800/year. If the firm service level were <u>not</u> reached during an event, the energy used above the firm service level would be penalized at a rate of about $10/kWh ($6/kWh for PG&E and SDG&E) for each 15 minute interval in which the FSL was exceeded. In our example, if the 700 kW customer with a firm service level of 500 kW only reduced to 550 kW for the duration of a 4-hour event, the penalty would be $10 x 4 hrs x 50 kW = $2,000 for that event ($6 x 4 hrs x 50 kW = $1,200 for PG&E and SDG&E) . If the same customer did not reduce at all for that event, the penalty would be $10 x 4 hours x 200 kW, or $8,000 ($6 x 4 hours x 200 kW, or $4800 for PG&E and SDG&E).*

8. Given this description (or given your knowledge of BIP), what are your thoughts about BIP as an alternative rate for your company (or to your current interruptible rate)?
    a. Are there eligibility concerns? (probe for required FSL, minimum 100 kW or 15% reduction)
    b. What is your reaction to the amount of notification? (Probe for response to day-of, 30 minute notification; if that's a concern ask about interest in Option B, with 3 hour notification – and lower incentives/penalties as described below – PG&E and SDG&E only)
    c. Are there concerns regarding the length or number of curtailments (maximum of 4 hours per day, 10 events per month for Option A. If that's a concern ask about interest in Option B, with 3 hour per day max – and lower incentives/penalties as described below – PG&E and SDG&E only)
    d. What is your reaction to the level of incentives and penalties for BIP? (Remind them of $7/kW credit and $6 or $10/kWh penalties) [If customer expresses concern about the size of the penalty, ask about Option B (for PG&E and SDG&E customers)]: *There is an alternate version of the BIP program, known as Option B, where events are limited to 3 hours per day and, customers receive a reduced credit of $3 per kW curtailed, but are also subject to a reduced penalty of $2.50/kWh.*

e. What business operational or other risks would you be considering in deciding whether or not to participate in BIP? (Probe for production/output, customer or employee comfort, other reasons for inability to drop load.)
f. What changes would you recommend for BIP that would make it more worthwhile for you to participate? (probe about structure, payment schedule, payment amounts, penalty amounts, notification, etc.)
g. If there were no changes in your current rate and the BIP program, how likely do you think you would be to enroll in the BIP program before next summer? Would you be more likely to participate in BIP Option B? Why or why not.
h. (INTERRUPTIBLE PARTICIPANTS ONLY) If, as described above, the interruptible rate you are on were discontinued, how likely do you think you would be to enroll in the BIP program?

9. For nonparticipants willing to consider signing up for BIP: If you were to sign up for BIP, what amount of load do you think you would be able to shift off peak or curtail?

10. For current traditional interruptible customers willing to consider signing up for BIP:
    a. What amount of load do you currently make available to shift off peak or curtail under your current rate?
    b. If you signed up for BIP, would you plan to have that same level of impact, more impact, or less impact? Why do you say that?

<u>V. Recent Control Events</u>:

11. FOR CURRENT TRADITIONAL INTERRUPTIBLE CUSTOMERS WHO HAVE BEEN INTERRUPTED IN 2005: What thoughts do you have about this summer's interruptible events? (Concerns with business operations, problems with notification, level of support; suggestions for improvement.)

12. DROPOUTS AND NON-PARTICIPANTS: Have you been aware of load curtailment events being called for customers on interruptible rates this summer? If so, what are your thoughts about those events, and how do those thoughts influence the likelihood of considering signing up for BIP or another interruptible or demand-response rate?

<u>VI. Final Thoughts/Comments:</u>

13. Participants: Do you have any final comments regarding the [AL TOU CP, I-6 or Schedule 19/20 Non-Firm] program? About the BIP program?

14. [Dropouts and non-participants] Do you have any other thoughts regarding the relative attractiveness of BIP compared to the firm rate you're now on and other programs or tariffs you are familiar with?

Those are all the questions I have for you. Thank you very much for your time and input.

B6. 2005 DRP Participant Survey Instrument

2005 DRP Participant Customer Survey
Draft Instrument, 11/29/2005

INTRODUCTION

Screening, general introduction, and confirmation of participation status

PROGRAM SATISFACTION

PS1. How long have you been participating in the California Demand Reserves Partnership, or DRP, program? (DO NOT PROMPT)

1	1 year	PS2
2	2 years	PS2
3	3 years	PS2
11	More than 3 years	PS2
88	Refused	PS2
99	Don't Know	PS2

PS2. What other demand response programs or tariffs, if any, were you participating in before you signed up for DRP?

1	No other program	PS2a
2	Interruptible or non-firm tariff	PS2a
3	Demand Bidding Program (DBP)	PS2a
4	OBMC	PS2a
5	Scheduled Load Reduction Program (SLRP)	PS2a
6	Rolling Blackout Reduction Program (RBRP)	PS2a
77	Other (specify)	PS2a
88	Refused	PS2a
99	Don't Know	PS2a

PS2a. What other rates or programs, if any, did you consider as alternatives to signing up for the DRP program?

1	No other program	PS2b
2	Interruptible or non-firm tariff	PS2b
3	Critical Peak Pricing (CPP)	PS2b
4	Demand Bidding (DBP)	PS2b
5	Base Interruptible Program (BIP)	PS2b
6	OBMC	PS2b
7	Scheduled Load Reduction Program (SLRP)	PS2b
8	Rolling Blackout Reduction Program (RBRP)	PS2b
77	Other (specify)	PS2b
88	Refused	PS2b
99	Don't Know	PS2b

PS2b. What was the primary reason for signing up for the DRP program? (DO NOT PROMPT)

1	Save money on energy costs/bills	PS2c

2	Being able to participate without significantly affecting business operations	PS2c
3	Being a good corporate citizen	PS2c
4	Avoiding rolling blackouts	PS2c
5	Receiving community recognition for organization's participation	PS2c
77	Other (specify)	PS2c
88	Refused	PS2c
99	Don't Know	PS2c

PS2c. Which features of the DRP program are most attractive to your organization? (DO NOT PROMPT - MULTIPLE ANSWERS OK)

1	Pricing/incentives	PS2d
2	Penalty levels or structure	PS2d
3	Event notification	PS2d
4	Event frequency	PS2d
5	Event duration	PS2d
6	Length of settlement process	PS2d
7	Through third party – not utility	PS2d
77	Other (specify)	PS2d
88	Refused	PS2d
99	Don't Know	PS2d

PS2d. Which features do you **not** like about the DRP program? (DO NOT PROMPT - MULTIPLE ANSWERS OK)

1	Pricing/incentives	PS2e
2	Penalty levels or structure	PS2e
3	Event notification	PS2e
4	Event frequency	PS2e
5	Event duration	PS2e
6	Length of settlement process	PS2e
7	Through third party – not utility	PS2e
8	Uncertainty about program's future	PS2e
9	Program complexity	PS2e
88	Refused	PS2e
99	Don't Know	PS2e

PS2e. How did you select the aggregator you currently work with for the DRP program? (DO NOT PROMPT)

1	Recommended by trade association	PS3
2	Reviewed several aggregator offerings and chose best one	PS3
3	Previous business relationship	PS3
4	Selected one from list on website	PS3
5	Selected by someone else in our organization	PS3
6	Other (specify)	PS3
88	Refused	PS3
99	Don't Know	PS3

PS3. Now, based on your participation to date, I would like you to rate your satisfaction with various aspects of the DRP program. Please tell me if you were very satisfied, somewhat satisfied, somewhat dissatisfied, or very dissatisfied with each of the following:

PS3a. The enrollment process.

1	Very satisfied	PS3b
2	Somewhat satisfied	PS3b
3	Somewhat dissatisfied	PS3b
4	Very dissatisfied	PS3b
88	Refused	PS3b
99	Don't Know	PS3b

PS3b. The range of interruption options offered (i.e., 1-3, 1-5, or 1-8 hours).

1	Very satisfied	PS3c
2	Somewhat satisfied	PS3c
3	Somewhat dissatisfied	PS3c
4	Very dissatisfied	PS3c
88	Refused	PS3c
99	Don't Know	PS3c

PS3c. The nomination or bidding process.

1	Very satisfied	PS3d
2	Somewhat satisfied	PS3d
3	Somewhat dissatisfied	PS3d
4	Very dissatisfied	PS3d
88	Refused	PS3d
99	Don't Know	PS3d

PS3d. The notification process for interruption events

1	Very satisfied	PS3e
2	Somewhat satisfied	PS3e
3	Somewhat dissatisfied	PS3e
4	Very dissatisfied	PS3e
88	Refused	PS3e
99	Don't Know	PS3e

PS3e. The frequency of interruption events

1	Very satisfied	PS3f
2	Somewhat satisfied	PS3f
3	Somewhat dissatisfied	PS3f
4	Very dissatisfied	PS3f
88	Refused	PS3f
99	Don't Know	PS3f

PS3f. The duration of interruption events

1	Very satisfied	PS3g
2	Somewhat satisfied	PS3g
3	Somewhat dissatisfied	PS3g
4	Very dissatisfied	PS3g
88	Refused	PS3g
99	Don't Know	PS3g

PS3g. The capacity payment for participation

1	Very satisfied	PS3h
2	Somewhat satisfied	PS3h
3	Somewhat dissatisfied	PS3h
4	Very dissatisfied	PS3h
88	Refused	PS3h
99	Don’t Know	PS3h

PS3h. The energy payment for participation

1	Very satisfied	PS3i
2	Somewhat satisfied	PS3i
3	Somewhat dissatisfied	PS3i
4	Very dissatisfied	PS3i
88	Refused	PS3i
99	Don’t Know	PS3i

PS3i. The timeliness of payments for participation

1	Very satisfied	PS3j
2	Somewhat satisfied	PS3j
3	Somewhat dissatisfied	PS3j
4	Very dissatisfied	PS3j
88	Refused	PS3j
99	Don’t Know	PS3j

PS3j. The level of penalties for failure to curtail during interruption events

1	Very satisfied	PS3h
2	Somewhat satisfied	PS3h
3	Somewhat dissatisfied	PS3h
4	Very dissatisfied	PS3h
88	Refused	PS3h
99	Don’t Know	PS3h

PS3k. The information provided regarding your performance on curtailments

1	Very satisfied	PS3i
2	Somewhat satisfied	PS3i
3	Somewhat dissatisfied	PS3i
4	Very dissatisfied	PS3i
88	Refused	PS3i
99	Don’t Know	PS3i

PS4. Overall, how satisfied are you with your participation in this program?

1	Very satisfied	PS5
2	Somewhat satisfied	PS5
3	Somewhat dissatisfied	PS4a
4	Very dissatisfied	PS4a
88	Refused	PS5

99	Don't Know	PS5

[IF PS4 = 3 or 4, then ask PS4; ELSE SKIP TO PS5]

PS4a. Could you briefly summarize why your experience with the DRP program has been unsatisfactory?

77	Record verbatim	PS5
88	Refused	PS5
99	Don't Know	PS5

PS5. Have changed your monthly nominations since you first enrolled in this program?

1	Yes	PS5a
2	No	PS5c
88	Refused	PS5c
99	Don't Know	PS5c

[IF PS5 = 1, then ask PS5a; ELSE SKIP TO PS5c]

PS5a. Have you increased or decreased your monthly nomination?

1	Increased	PS5b
2	Decreased	PS5b
3	Varies from month to month	PS5b
88	Refused	PS5b
99	Don't Know	PS5b

PS5b. Could you briefly summarize why you changed your monthly nomination? (DO NOT PROMPT)

1	Previous nominations were too much	EX1
2	Changes in curtailment options forced cutback	EX1
3	Able to increase nomination because of business/production	
4	Cut back nomination because of business/production requirements	
77	Other (specify)	EX1
88	Refused	EX1
99	Don't Know	EX1

PS5c. In addition to monthly nominations, have you also made daily nominations?

1	Yes	PS5d
2	No	EX1
88	Refused	EX1
99	Don't Know	EX1

[IF PS5c = 1, then ask PS5d; ELSE SKIP TO EX1]

PS5d. In about how many months did you make daily nominations in addition to monthly nominations? Would you say you made daily nominations:

1	Less than half the months in which you made monthly nominations	EX1
2	More than half the months in which you made monthly nominations	EX1
3	Every month in which you made a monthly nomination	EX1
77	Other (specify)	EX1

88	Refused	EX1
99	Don't Know	EX1

2005 EVENT EXPERIENCE

EX1. How often was your organization called upon to curtail in 2005, not including test events? (DO NOT PROMPT)

77	Record number	EX2
88	Refused	EX2
99	Don't Know	EX2

EX2. Does your organization have a pre-established curtailment strategy?

1	Yes	EX3
2	No	EX3
88	Refused	EX3
99	Don't Know	EX3

EX3. What specific actions do you take to reduce load during curtailment event(s)? (READ LIST - MULTIPLE ANSWERS OK)

1	Turn off/reduced overhead lighting	EX3a
2	Turn off computers and other office equipment	EX3a
3	Reduce thermostat temperature setting	EX3a
4	Shut down some or all production processes	EX3a
5	Shift production to other day or period	EX3a
6	Shut down some or all refrigeration/cold storage	EX3a
7	Run back-up generators	EX3a
77	Other action (specify)	EX3a
88	Refused	EX3a
99	Don't Know	EX3a

EX3a. To what extent are these load reductions centrally controlled, as opposed to being a diffuse set of manual actions? Would you say these load reductions are…

1	Entirely centrally controlled	EX5
2	Partially centrally controlled	EX5
3	Not at all centrally controlled	EX5
88	Refused	EX5
99	Don't Know	EX5

EX5. What software, if any, do you use to track your energy usage and manage your load reductions?

1	InterAct or Interact II (PG&E)	EX5a
2	Energy Manager (SCE)	EX5a
3	kWickview (SDG&E)	EX5a
4	Other (specify)	EX5a
5	None	EX6
88	Refused	EX6
99	Don't Know	EX6

[IF EX5 = 1, then ask EX5a; ELSE SKIP TO EX6]

EX5a. How useful has that software been in managing or planning your load reductions? Would you say…

1	Very helpful	EX5b
2	Somewhat helpful	EX5b
3	Not at all helpful	EX6
4	Never used it	EX6
88	Refused	EX6
99	Don't Know	EX6

[IF EX5a = 1 or 2, then ask EX5b; ELSE SKIP TO EX6]

EX5b. What aspects of the software have been the most useful in managing or planning your load reductions?

77	Record verbatim	EX6
88	Refused	EX6
99	Don't Know	EX6

EX6. Would you say that it is generally easy or difficult for your organization to curtail the amount of load required in the required timeframe? Would you say:

1	Very easy	EX6a
2	Somewhat easy	EX6a
3	Somewhat difficult	EX6a
4	Very difficult	EX6a
88	Refused	GF1
99	Don't Know	GF1

[IF EX6 = 1, 2, 3, or 4, then ask EX6a; ELSE SKIP TO GF1]

EX6a. Briefly, what is the main reason why your organization has found it [ANSWER TO EX6] to curtail in the required timeframe?

77	Record verbatim	GF1
88	Refused	GF1
99	Don't Know	GF1

OUTLOOK GOING FORWARD

GF1. Do you anticipate remaining in the DRP program next summer?

1	Yes	GF2
2	No	GF1a
88	Refused	GF2
99	Don't Know	GF2

[IF GF1 = 2, then ask GF1a; ELSE SKIP TO GF2]

GF1a. What other rate or program would you be most likely to consider? (DO NOT PROMPT - MULTIPLE ANSWERS OK)

1	Critical Peak Pricing (CPP)	GF1b
2	Demand Bidding (DBP)	GF1b
3	Base Interruptible Program (BIP)	GF1b
4	OBMC	GF1b
5	Scheduled Load Reduction Program (SLRP)	GF1b
6	Rolling Blackout Reduction Program (RBRP)	GF1b
77	Other (specify)	GF1b
88	Refused	GF3
99	Don't Know	GF3

[IF GF1a = 1, 2, 3, 4, 5, or 6, then ask GF1b; ELSE SKIP TO GF3]

GF1b. Which features of [PROGRAMS CITED IN GF1a] are most attractive to your organization? (DO NOT PROMPT - MULTIPLE ANSWERS OK)

1	Pricing/incentives	GF3
2	Penalty levels or structure	GF3
3	Event notification	GF3
4	Event frequency	GF3
5	Event duration	GF3
6	Length of settlement process	GF3
7	Reliability of supply	GF3
77	Other (specify)	GF3
88	Refused	GF3
99	Don't Know	GF3

GF2. In the last two years, have you considered participating in other demand response programs?

1	Yes	GF2a
2	No	GF3
88	Refused	GF3
99	Don't Know	GF3

[IF GF2 = 1, then ask GF2a; ELSE SKIP TO GF3]

GF2a. Did you consider participating in other demand response programs <u>in addition to</u> or <u>instead</u> of participating in the DRP program?

1	In addition to DRP	GF2b
2	Instead of DRP	GF2b
88	Refused	GF2b
99	Don't Know	GF2b

GF2b. If yes, which programs appealed to you? (DO NOT PROMPT - MULTIPLE ANSWERS OK)

1	Critical Peak Pricing (CPP)	GF2c
2	Demand Bidding (DBP)	GF2c
3	Base Interruptible Program (BIP)	GF2c
4	OBMC	GF2c
5	Scheduled Load Reduction Program (SLRP)	GF2c
6	Rolling Blackout Reduction Program (RBRP)	GF2c
77	Other (specify)	GF2c

88	Refused	GF2c
99	Don't Know	GF2c

GF2c. Which features of this program are most attractive to your organization? (DO NOT PROMPT - MULTIPLE ANSWERS OK)

1	Pricing/incentives	GF2d
2	Penalty levels or structure	GF2d
3	Event notification	GF2d
4	Event frequency	GF2d
5	Event duration	GF2d
6	Length of settlement process	GF2d
7	Reliability of supply	GF2d
77	Other (specify)	GF2d
88	Refused	GF2d
99	Don't Know	GF2d

GF2d. Which features did you **not** like about the programs you considered? (DO NOT PROMPT - MULTIPLE ANSWERS OK)

1	Pricing/incentives	GF3
2	Penalty levels or structure	GF3
3	Event notification	GF3
4	Event frequency	GF3
5	Event duration	GF3
6	Length of settlement process	GF3
7	Reliability of supply	GF3
8	Program complexity	GF3
88	Refused	GF3
99	Don't Know	GF3

GF3. Are you aware of the Technical Assistance –Technology Incentive Program to help customers identify demand response load reduction opportunities within their facility and help offset the costs of implementing those opportunities?

1	Yes	GF3a
2	No	GF4
88	Refused	GF4
99	Don't Know	GF4

[IF GF3 = 1, then ask GF3a; ELSE SKIP TO GF4]

GF3a. Are you planning to enroll in the Technical Assistance - Technology Incentive Program?

1	Yes	GF3a
2	No	GF4
88	Refused	GF4
99	Don't Know	GF4

[IF GF3a = 1, then ask GF3b; ELSE SKIP TO GF4]

GF3b. Which aspects of the Technical Assistance Incentive Program are you planning to use? (DO NOT PROMPT - MULTIPLE ANSWERS OK)

1	Preliminary audit	GF3a
2	Detailed technical audit	GF4
3	Financial incentives to install demand response measures	GF4
88	Refused	GF4
99	Don't Know	GF4

GF4. Under the terms of the DRP program, service interruptions are limited to a maximum of 24 hours per month, or a total of 150 hours per year. In a worst-case scenario where the maximum number of interruptions was called, how likely is it that your organization would remain in the DRP program?

1	Very likely	GF5
2	Somewhat likely	GF5
3	Somewhat unlikely	GF4a
4	Very unlikely	GF4a
88	Refused	GF5
99	Don't Know	GF5

[IF GF4 = 3 or 4, then ask GF4a; ELSE SKIP TO GF5]

GF4a. What is the upper limit on the number of hours of service interruption that your organization could withstand in a worst-case scenario before considering leaving the DRP program?

77	Record verbatim	GF4b
88	Refused	GF5
99	Don't Know	GF5

[IF GF4a = 77, then ask GF4b; ELSE SKIP TO GF5]

GF4b. If these upper limits actually occurred, which of the following actions are you most likely to take? (READ LIST)

1	Go to a firm service rate with no demand response participation	GF5
2	Go to a firm service rate and consider participating in other demand response programs	GF5
3	Look for a non-firm service rate or increase our non-firm load	GF5
4	Look for a non-firm service rate or increase our non-firm load and consider participating in other demand response programs	GF5
77	Other (specify)	GF5
88	Refused	GF5
99	Don't Know	GF5

GF5. The DRP program is currently scheduled to run through 2006. Which of the following statements best describes your organization's preference regarding the future role of the DRP program for 2007 and beyond? (READ LIST)

1	We would like to see the DRP remain in place in its current form	GF6
2	We would like to see a program like the DRP, but with changes	GF5a
3	We don't care whether a program like the DRP is available or not	GF6
77	Other (specify)	GF6
88	Refused	GF6
99	Don't Know	GF6

GF5a. What changes would you like to see to the DRP program for 2007 and beyond?

77	Record verbatim	GF6
88	Refused	GF6
99	Don't Know	GF6

GF6. If the DRP program were discontinued after 2006, which of the following actions would you be most likely to take? (READ LIST)

1	Go to a firm service rate with no demand response participation	EC1
2	Go to a firm service rate and consider participating in demand response programs	EC1
3	Look for a non-firm service rate or increase our non-firm load	EC1
4	Look for a non-firm service rate or increase our non-firm load and consider participating in demand response programs	EC1
77	Other (specify)	EC1
88	Refused	EC1
99	Don't Know	EC1

FIRMOGRAPHIC CHARACTERISTICS

Now I'd like to ask a few quick questions about this facility. Unless otherwise stated, all questions pertain to [THIS FACILITY]. (RESTATE FACILITY LOCATION IF NECESSARY)

EC1. What is the main activity performed at this location?

1	Office	EC2
2	Retail (non-food)	EC2
3	College/university	EC2
4	School	EC2
5	Grocery store	EC2
6	Convenience store	EC2
7	Restaurant	EC2
8	Health care/hospital	EC2
9	Hotel or motel	EC2
10	Warehouse	EC2
11	Personal Service	EC2
12	Community Service/Church/Temple/Municipality	EC2
13	Industrial Electronic & Machinery	EC2
14	Industrial Mining, Metals, Stone, Glass, Concrete	EC2
15	Industrial Petroleum, Plastic, Rubber and Chemicals	EC2
16	Other Industrial	EC2
17	Agricultural	EC2
18	Transportation/Telecommunications/Utility	EC2
77	Other (SPECIFY)	EC2
88	Refused	EC2
99	Don't know	EC2

EC2. Approximately how many square feet does your organization occupy in this facility?

1	Less than 10,000 square feet	EC3
2	10,000 but less than 20,000 square feet	EC3
3	20,000 but less than 50,000 square feet	EC3
4	50,000 but less than 100,000 square feet	EC3

5	100,000 but less than 200,000 square feet	EC3
6	200,000 but less than 300,000 square feet	EC3
7	300,000 but less than 400,000 square feet	EC3
8	400,000 but less than 500,000 square feet	EC3
9	Over 500,000 square feet	EC3
10	Ag/Non-facility – Outdoors	EC3
88	Refused	EC3
99	Don't know	EC3

EC3. Does your organization...

1	Own this space	EC5
2	Lease this space	EC5
3	Own a portion and lease the remainder	EC5
88	Refused	EC5
99	Don't know	EC5

EC5. What percent of your organization's total annual operating costs do energy costs represent?

1	Less than 1 percent	EC5A
2	1 to 4 percent	EC5A
3	5 to 10 percent	EC5A
4	11 to 25 percent	EC5A
5	Over 25	EC5A
88	Refused	EC5A
99	Don't know	EC5A

EC5A. Has your organization assigned responsibility for controlling energy usage and costs to any of the following?

1	An in-house staff person	EC6
2	A group of staff	EC6
3	An outside contractor	EC6
4	No one	EC6
88	Refused	EC6
99	Don't know	EC6

EC6. Approximately how many locations does your organization have in California?

1	1	EC7
2	2 to 4	EC7
3	5 to 10	EC7
4	11 to 25	EC7
5	Over 25	EC7
88	Refused	EC7
99	Don't know	EC7

EC7. What is the approximate number of full-time equivalent workers of all types employed by your organization at this facility?

1	1 to 10	EC9A
2	11 to 50	EC9A
3	51 to 100	EC9A

4	100 to 250	EC9A
5	251 to 500	EC9A
7	501 to 1000	EC9A
8	Or, over 1000	EC9A
88	[Don't read] Refused	EC9A
99	[Don't read] Don't know	EC9A

EC9A. Which of the following is the LARGEST end use in terms of electricity consumption for this facility?

1	Lighting	EC9B
2	HVAC	EC9B
3	Continuous processing	EC9B
4	Batch processing	EC9B
5	Refrigeration	EC9B
77	Other, Specify_____________	EC9B
88	Refused	EC9B
99	Don't know	EC9B

EC9B. And which would you say used the SECOND most electricity?

1	Lighting	EC10
2	HVAC	EC10
3	Continuous processing	EC10
4	Batch processing	EC10
5	Refrigeration	EC10
77	Other, Specify_____________	EC10
88	Refused	EC10
99	Don't know	EC10

EC10. Does this location have any on-site electricity generators?

1	Yes, for backup/standby purposes only	EC10a
2	Yes, as an everyday supplement or replacement for electricity purchases from the grid	EC10a
3	No	CL1
88	Refused	CL1
99	Don't know	CL1

[IF EC10 = 1 or 2, then EC10a; ELSE SKIP TO CL1]

EC10a. What percent of this location's electricity load can be met by your on-site generation?

______ Percent (allow > 100%)

EC10b. Are their legal restrictions on the number of hours your on-site system can run during the summer?

1	Yes	CL1
2	No	CL1
88	Refused	CL1
99	Don't know	CL1

CLOSE

CL1. Do you have any final comments or suggestions about the DRP program?

<VERBATIM>

APPENDIX C
SURVEY RESULTS

C1. 2005 Non-Participant Market Survey Results

		Business Type									Business Size				Utility					
SC1. What is your job title?	Total	Office	Retail/Grocery	Institutional	Other Commercial	Transportation, Communication, Utility	Petroleum, Plastic, Rubber and Chemicals	Mining, Metals, Stone, Glass, Concrete	Electronic, Machinery, and Fabricated Metals	Other Industrial and Agriculture	Extra Large (2000+ kW)	Large (1000-2000 kW)	Medium (500-1000 kW)	Small (100/200-500 kW) *	PG&E	SCE	SDG&E	Number of Respondents	Percent of Respondents	Percent of Premises
Facilities Manager	33%	24%	17%	40%	33%	40%	19%	19%	64%	36%	40%	35%	42%	18%	40%	29%	29%	182	32%	33%
Energy Manager	4%	3%	6%	8%	0%	3%	0%	3%	1%	9%	3%	2%	5%	6%	3%	5%	4%	25	4%	4%
Other facilities management/maintenance	13%	18%	5%	22%	15%	16%	2%	3%	15%	11%	14%	12%	7%	16%	12%	12%	21%	78	14%	13%
Chief Financial Officer	6%	1%	5%	1%	2%	1%	0%	58%	0%	1%	12%	0%	2%	3%	1%	10%	5%	13	2%	6%
Other financial/administrative position	22%	21%	58%	10%	24%	24%	12%	3%	13%	24%	5%	23%	26%	41%	22%	23%	17%	121	21%	22%
Proprietor/Owner	1%	1%	0%	0%	2%	0%	2%	0%	1%	2%	1%	1%	0%	2%	1%	1%	1%	16	3%	1%
President/CEO	2%	0%	1%	1%	1%	0%	3%	1%	1%	6%	0%	5%	3%	2%	1%	3%	1%	23	4%	2%
Plant Manager	6%	0%	2%	3%	7%	1%	48%	10%	1%	2%	11%	6%	5%	1%	5%	8%	3%	31	5%	6%
Controller	0%	0%	0%	0%	0%	0%	0%	0%	1%	0%	0%	0%	0%	0%	0%	0%	0%	3	1%	0%
Engineer	8%	25%	1%	8%	13%	5%	2%	2%	3%	7%	9%	12%	8%	5%	9%	5%	15%	47	8%	8%
Operations	5%	7%	3%	6%	3%	11%	12%	0%	0%	1%	5%	4%	2%	6%	7%	3%	4%	32	6%	5%
N	571	71	46	80	83	58	52	43	67	71	87	101	155	228	211	192	168	571	100%	100%

		Business Type									Business Size				Utility					
RESP. Are you responsible for any other facilities in the service territory?	Total	Office	Retail/Grocery	Institutional	Other Commercial	Transportation, Communication, Utility	Petroleum, Plastic, Rubber and Chemicals	Mining, Metals, Stone, Glass, Concrete	Electronic, Machinery, and Fabricated Metals	Other Industrial and Agriculture	Extra Large (2000+ kW)	Large (1000-2000 kW)	Medium (500-1000 kW)	Small (100/200-500 kW) *	PG&E	SCE	SDG&E	Number of Respondents	Percent of Respondents	Percent of Premises
Yes	43%	33%	55%	44%	29%	50%	57%	61%	30%	42%	44%	27%	39%	52%	32%	54%	41%	194	34%	43%
No	57%	67%	45%	56%	71%	50%	43%	39%	70%	57%	56%	73%	61%	47%	68%	46%	59%	378	66%	57%
DON'T KNOW	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	0%	0%	0%	0%	0%	0%	0%	1	0%	0%
N	573	71	46	81	83	58	52	44	67	71	88	101	155	229	212	192	169	573	100%	100%

		Business Type									Business Size				Utility					
HOWMANY. How many facilites in the service area are you responsible for?	Total	Office	Retail/Grocery	Institutional	Other Commercial	Transportation, Communication, Utility	Petroleum, Plastic, Rubber and Chemicals	Mining, Metals, Stone, Glass, Concrete	Electronic, Machinery, and Fabricated Metals	Other Industrial and Agriculture	Extra Large (2000+ kW)	Large (1000-2000 kW)	Medium (500-1000 kW)	Small (100/200-500 kW) *	PG&E	SCE	SDG&E	Number of Respondents	Percent of Respondents	Percent of Premises
1	3%	3%	0%	8%	0%	7%	0%	3%	1%	0%	2%	7%	6%	0%	2%	4%	1%	9	5%	3%
2	28%	34%	16%	6%	24%	16%	77%	1%	63%	45%	38%	27%	40%	12%	40%	26%	11%	56	29%	28%
3	10%	26%	5%	11%	20%	5%	4%	0%	23%	4%	5%	21%	12%	11%	7%	9%	18%	34	18%	10%
4	13%	4%	8%	1%	1%	0%	0%	95%	4%	5%	27%	4%	2%	6%	2%	21%	4%	10	5%	13%
5	8%	15%	6%	2%	12%	19%	19%	1%	2%	1%	6%	21%	0%	10%	10%	3%	24%	14	7%	8%
6	5%	2%	1%	5%	1%	0%	0%	0%	7%	26%	9%	6%	5%	1%	13%	2%	1%	8	4%	5%
7	2%	0%	2%	7%	6%	0%	0%	0%	0%	0%	0%	6%	4%	2%	2%	1%	5%	6	3%	2%
8	1%	0%	1%	6%	2%	0%	0%	0%	0%	0%	0%	0%	5%	1%	0%	1%	3%	5	3%	1%
10	1%	10%	0%	0%	2%	3%	0%	0%	0%	0%	0%	0%	7%	0%	0%	2%	3%	4	2%	1%
11	0%	2%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	0%	0%	2%	1	1%	0%
12	3%	0%	0%	3%	0%	0%	0%	1%	0%	16%	1%	0%	2%	4%	2%	4%	0%	5	3%	3%
13	0%	3%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	0%	0%	2%	1	1%	0%
14	1%	1%	0%	3%	0%	1%	0%	0%	0%	0%	0%	0%	3%	0%	0%	1%	1%	3	2%	1%
15	0%	0%	0%	0%	0%	2%	0%	0%	0%	0%	0%	1%	0%	0%	1%	0%	0%	2	1%	0%
16	1%	0%	0%	6%	0%	1%	0%	0%	0%	0%	0%	0%	0%	3%	0%	1%	1%	3	2%	1%
20	1%	0%	2%	2%	5%	0%	0%	0%	0%	1%	1%	2%	0%	2%	3%	0%	2%	6	3%	1%
21	0%	0%	0%	0%	0%	2%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1	1%	0%
22	6%	0%	40%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	17%	0%	10%	0%	1	1%	6%
24	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1	1%	0%
26	0%	0%	0%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	0%	0%	1	1%	0%
27	0%	0%	0%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1	1%	0%
30	0%	0%	0%	0%	0%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1	1%	0%
36	1%	0%	0%	5%	0%	0%	0%	0%	0%	0%	0%	0%	0%	2%	0%	2%	0%	1	1%	1%
40	4%	0%	1%	21%	0%	0%	0%	0%	0%	0%	5%	1%	0%	4%	7%	2%	0%	3	2%	4%
44	0%	0%	0%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1	1%	0%
50	1%	0%	6%	0%	0%	3%	0%	0%	0%	0%	0%	3%	3%	1%	0%	1%	2%	3	2%	1%
52	1%	0%	0%	0%	0%	8%	0%	0%	0%	0%	2%	0%	0%	0%	3%	0%	0%	1	1%	1%
53	1%	0%	0%	8%	0%	0%	0%	0%	0%	0%	0%	0%	0%	4%	5%	0%	0%	1	1%	1%
60	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1	1%	0%
62	1%	0%	0%	0%	0%	13%	0%	0%	0%	0%	0%	0%	0%	4%	0%	2%	0%	1	1%	1%
79	0%	0%	0%	0%	0%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1	1%	0%
80	2%	0%	11%	3%	0%	0%	0%	0%	0%	0%	0%	0%	9%	1%	0%	3%	3%	2	1%	2%
97	1%	0%	0%	0%	17%	0%	0%	0%	0%	0%	0%	0%	0%	4%	0%	0%	11%	1	1%	1%
100	1%	0%	0%	0%	6%	0%	0%	0%	0%	0%	1%	0%	0%	0%	0%	1%	0%	1	1%	1%
150	1%	0%	0%	0%	0%	7%	0%	0%	0%	0%	0%	0%	0%	2%	3%	0%	0%	1	1%	1%
Don't know	2%	0%	1%	0%	4%	13%	0%	0%	0%	0%	0%	0%	0%	5%	1%	2%	2%	3	2%	2%
N	194	25	23	38	22	24	12	9	19	22	29	27	54	84	59	75	60	194	100%	100%

Awareness

F1. California has developed several programs to promote demand response. Have you heard about any of these programs?	Total	Business Type									Business Size				Utility			Number of Respondents	Percent of Respondents	Percent of Premises
		Office	Retail/Grocery	Institutional	Other Commercial	Transportation, Communication, Utility	Petroleum, Plastic, Rubber and Chemicals	Mining, Metals, Stone, Glass, Concrete	Electronic, Machinery, and Fabricated Metals	Other Industrial and Agriculture	Extra Large (2000+ kW)	Large (1000-2000 kW)	Medium (500-1000 kW)	Small (100/200-500 kW) *	PG&E	SCE	SDG&E			
Yes	79%	70%	77%	91%	66%	75%	57%	89%	92%	83%	79%	88%	84%	70%	73%	83%	79%	439	77%	79%
No	21%	28%	23%	9%	34%	25%	43%	11%	8%	17%	21%	11%	16%	30%	27%	17%	20%	132	23%	21%
Don't know	0%	2%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	0%	0%	0%	0%	1%	2	0%	0%
N	573	71	46	81	83	58	52	44	67	71	88	101	155	229	212	192	169	573	100%	100%

F1A. Which programs have you heard of?	Total	Business Type									Business Size				Utility			Number of Respondents	Percent of Respondents	Percent of Premises
		Office	Retail/Grocery	Institutional	Other Commercial	Transportation, Communication, Utility	Petroleum, Plastic, Rubber and Chemicals	Mining, Metals, Stone, Glass, Concrete	Electronic, Machinery, and Fabricated Metals	Other Industrial and Agriculture	Extra Large (2000+ kW)	Large (1000-2000 kW)	Medium (500-1000 kW)	Small (100/200-500 kW) *	PG&E	SCE	SDG&E			
CPP Critical Peak Pricing	24%	21%	30%	19%	16%	13%	16%	79%	14%	19%	25%	27%	30%	17%	21%	29%	16%	96	22%	24%
DB Demand Bidding	28%	18%	24%	19%	17%	18%	25%	87%	40%	20%	41%	22%	27%	13%	24%	36%	13%	78	18%	28%
Demand Reserves Partnership	9%	8%	11%	11%	10%	9%	6%	18%	4%	4%	7%	10%	21%	3%	11%	8%	5%	41	9%	9%
Base Interruptible Program	10%	4%	20%	19%	7%	11%	6%	12%	3%	5%	6%	13%	18%	10%	9%	13%	5%	46	10%	10%
20/20 program	3%	4%	1%	4%	6%	7%	1%	0%	3%	0%	1%	5%	5%	3%	0%	2%	13%	23	5%	3%
EE Audit / Retrofit	4%	8%	2%	10%	0%	0%	1%	0%	0%	3%	5%	3%	1%	3%	2%	5%	4%	16	4%	4%
Cogen / On-site generation	0%	0%	0%	0%	0%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	3	1%	0%
General awareness / Do not recall names	5%	12%	5%	5%	5%	8%	0%	2%	5%	2%	3%	6%	10%	4%	7%	3%	7%	34	8%	5%
Interruptible service / Load shedding / Load control	8%	4%	0%	4%	0%	0%	4%	66%	3%	1%	16%	2%	3%	2%	0%	15%	3%	13	3%	8%
Meter program	0%	0%	0%	0%	0%	4%	0%	0%	0%	0%	0%	0%	0%	1%	1%	0%	0%	3	1%	0%
Voluntary load reduction	0%	0%	0%	0%	0%	3%	1%	0%	0%	0%	0%	0%	2%	0%	0%	1%	0%	5	1%	0%
Other - Record program name	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0	0%	0%
Refused	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0	0%	0%
Don't know	48%	47%	59%	43%	64%	57%	56%	10%	37%	57%	43%	46%	47%	57%	53%	43%	51%	218	50%	48%
N	439	51	34	69	60	43	44	33	50	55	74	84	128	153	159	152	128	439	131%	140%

F2a. How familiar is your organization with your utility's voluntary Critical Peak Pricing tariff?	Total	Business Type									Business Size				Utility			Number of Respondents	Percent of Respondents	Percent of Premises
		Office	Retail/Grocery	Institutional	Other Commercial	Transportation, Communication, Utility	Petroleum, Plastic, Rubber and Chemicals	Mining, Metals, Stone, Glass, Concrete	Electronic, Machinery, and Fabricated Metals	Other Industrial and Agriculture	Extra Large (2000+ kW)	Large (1000-2000 kW)	Medium (500-1000 kW)	Small (100/200-500 kW) *	PG&E	SCE	SDG&E			
Very familiar	24%	17%	44%	30%	12%	19%	7%	20%	20%	35%	22%	27%	20%	27%	19%	27%	27%	125	22%	24%
Somwhat familiar	50%	53%	23%	57%	51%	47%	32%	67%	70%	45%	56%	46%	50%	43%	49%	51%	47%	276	48%	50%
Not at all familiar	26%	30%	33%	13%	37%	31%	59%	13%	10%	20%	22%	26%	29%	30%	31%	22%	26%	169	30%	26%
Don't know	0%	0%	0%	0%	0%	3%	2%	0%	0%	0%	0%	1%	1%	0%	1%	0%	0%	3	1%	0%
N	573	71	46	81	83	58	52	44	67	71	88	101	155	229	212	192	169	573	100%	100%

F2B. How familiar is your organization with your utility's Demand Bidding Program?	Total	Business Type									Business Size				Utility			Number of Respondents	Percent of Respondents	Percent of Premises
		Office	Retail/Grocery	Institutional	Other Commercial	Transportation, Communication, Utility	Petroleum, Plastic, Rubber and Chemicals	Mining, Metals, Stone, Glass, Concrete	Electronic, Machinery, and Fabricated Metals	Other Industrial and Agriculture	Extra Large (2000+ kW)	Large (1000-2000 kW)	Medium (500-1000 kW)	Small (100/200-500 kW) *	PG&E	SCE	SDG&E			
Very familiar	32%	19%	34%	31%	14%	32%	7%	76%	42%	39%	46%	25%	24%	21%	21%	44%	20%	114	20%	32%
Somwhat familiar	38%	39%	33%	39%	38%	20%	79%	15%	45%	32%	40%	39%	40%	32%	43%	33%	36%	215	38%	38%
Not at all familiar	31%	43%	33%	29%	47%	45%	14%	8%	13%	29%	14%	35%	34%	47%	35%	23%	43%	241	42%	31%
Don't know	0%	0%	0%	0%	0%	3%	0%	0%	0%	0%	0%	0%	1%	0%	1%	0%	0%	3	1%	0%
N	573	71	46	81	83	58	52	44	67	71	88	101	155	229	212	192	169	573	100%	100%

F2D. How familiar is your organization with the Cal - Demand Reserves Partnerhsip (DRP)	Total	Business Type									Business Size				Utility			Number of Respondents	Percent of Respondents	Percent of Premises
		Office	Retail/Grocery	Institutional	Other Commercial	Transportation, Communication, Utility	Petroleum, Plastic, Rubber and Chemicals	Mining, Metals, Stone, Glass, Concrete	Electronic, Machinery, and Fabricated Metals	Other Industrial and Agriculture	Extra Large (2000+ kW)	Large (1000-2000 kW)	Medium (500-1000 kW)	Small (100/200-500 kW) *	PG&E	SCE	SDG&E			
Very familiar	17%	11%	34%	29%	10%	21%	5%	17%	6%	18%	19%	14%	15%	18%	14%	21%	16%	70	12%	17%
Somwhat familiar	25%	22%	18%	28%	26%	12%	11%	65%	28%	24%	34%	25%	23%	16%	28%	25%	19%	125	22%	25%
Not at all familiar	57%	66%	49%	42%	64%	64%	82%	19%	66%	58%	47%	60%	60%	66%	58%	53%	65%	374	65%	57%
Refused	0%	0%	0%	1%	0%	0%	0%	0%	0%	0%	0%	0%	1%	0%	0%	0%	0%	1	0%	0%
Don't know	0%	0%	0%	0%	0%	3%	2%	0%	0%	0%	0%	1%	1%	0%	1%	0%	0%	3	1%	0%
N	573	71	46	81	83	58	52	44	67	71	88	101	155	229	212	192	169	573	100%	100%

F2E. How familiar is your organization with your utility's Base Interruptible Program (BIP)?	Total	Business Type									Business Size				Utility			Number of Respondents	Percent of Respondents	Percent of Premises
		Office	Retail/Grocery	Institutional	Other Commercial	Transportation, Communication, Utility	Petroleum, Plastic, Rubber and Chemicals	Mining, Metals, Stone, Glass, Concrete	Electronic, Machinery, and Fabricated Metals	Other Industrial and Agriculture	Extra Large (2000+ kW)	Large (1000-2000 kW)	Medium (500-1000 kW)	Small (100/200-500 kW) *	PG&E	SCE	SDG&E			
Very familiar	37%	15%	32%	37%	26%	26%	60%	88%	42%	33%	56%	32%	18%	27%	22%	55%	18%	120	21%	17%
Somwhat familiar	31%	36%	29%	29%	31%	45%	27%	5%	40%	35%	30%	34%	42%	25%	37%	27%	32%	193	34%	25%
Not at all familiar	31%	49%	39%	34%	43%	26%	13%	7%	18%	33%	14%	34%	39%	49%	40%	18%	49%	258	45%	57%
Don't know	0%	0%	0%	0%	0%	3%	0%	0%	0%	0%	0%	0%	1%	0%	1%	0%	0%	2	0%	0%
N	573	71	46	81	83	58	52	44	67	71	88	101	155	229	212	192	169	573	100%	100%

F6A. Have you had a general discussion with your utility representative of demand response program featrues?	Total	Business Type									Business Size				Utility			Number of Respondents	Percent of Respondents	Percent of Premises
		Office	Retail/Grocery	Institutional	Other Commercial	Transportation, Communication, Utility	Petroleum, Plastic, Rubber and Chemicals	Mining, Metals, Stone, Glass, Concrete	Electronic, Machinery, and Fabricated Metals	Other Industrial and Agriculture	Extra Large (2000+ kW)	Large (1000-2000 kW)	Medium (500-1000 kW)	Small (100/200-500 kW) *	PG&E	SCE	SDG&E			
Yes	59%	44%	59%	79%	55%	65%	38%	27%	80%	62%	62%	68%	61%	48%	56%	64%	48%	295	51%	59%
No	41%	56%	41%	21%	45%	35%	62%	73%	20%	36%	38%	31%	38%	52%	43%	36%	52%	275	48%	41%
Don't know	0%	0%	0%	0%	0%	0%	0%	0%	0%	2%	0%	0%	1%	1%	1%	0%	0%	3	1%	0%
N	573	71	46	81	83	58	52	44	67	71	88	101	155	229	212	192	169	573	100%	100%

F6B. Have you recevied any specific analysis of the financial impact of participating in the new demand response programs from your utility representative?	Total	Business Type									Business Size				Utility			Number of Respondents	Percent of Respondents	Percent of Premises
		Office	Retail/Grocery	Institutional	Other Commercial	Transportation, Communication, Utility	Petroleum, Plastic, Rubber and Chemicals	Mining, Metals, Stone, Glass, Concrete	Electronic, Machinery, and Fabricated Metals	Other Industrial and Agriculture	Extra Large (2000+ kW)	Large (1000-2000 kW)	Medium (500-1000 kW)	Small (100/200-500 kW) *	PG&E	SCE	SDG&E			
Yes	29%	13%	47%	32%	23%	17%	18%	78%	19%	22%	30%	30%	26%	27%	20%	37%	27%	146	25%	29%
No	68%	83%	47%	63%	73%	80%	82%	22%	80%	73%	70%	69%	63%	67%	77%	58%	72%	407	71%	68%
Don't know	4%	4%	6%	6%	3%	4%	0%	0%	1%	5%	0%	1%	10%	5%	3%	5%	1%	20	3%	4%
N	573	71	46	81	83	58	52	44	67	71	88	101	155	229	212	192	169	573	100%	100%

F6C. Have you received brochures and print materials about demand response programs?	Total	Business Type									Business Size				Utility			Number of Respondents	Percent of Respondents	Percent of Premises
		Office	Retail/Grocery	Institutional	Other Commercial	Transportation, Communication, Utility	Petroleum, Plastic, Rubber and Chemicals	Mining, Metals, Stone, Glass, Concrete	Electronic, Machinery, and Fabricated Metals	Other Industrial and Agriculture	Extra Large (2000+ kW)	Large (1000-2000 kW)	Medium (500-1000 kW)	Small (100/200-500 kW) *	PG&E	SCE	SDG&E			
Yes	64%	44%	63%	75%	56%	58%	49%	88%	88%	60%	71%	56%	67%	58%	52%	76%	63%	351	61%	64%
No	32%	50%	37%	21%	39%	41%	49%	4%	10%	38%	26%	38%	28%	41%	43%	23%	36%	196	34%	32%
Don't know	3%	5%	0%	4%	5%	1%	2%	9%	1%	2%	3%	5%	5%	1%	6%	2%	1%	26	5%	3%
N	573	71	46	81	83	58	52	44	67	71	88	101	155	229	212	192	169	573	100%	100%

F7. How helpful was this information in determining whether demand response programs would be of interest to your organization?	Total	Business Type									Business Size				Utility			Number of Respondents	Percent of Respondents	Percent of Premises
		Office	Retail/Grocery	Institutional	Other Commercial	Transportation, Communication, Utility	Petroleum, Plastic, Rubber and Chemicals	Mining, Metals, Stone, Glass, Concrete	Electronic, Machinery, and Fabricated Metals	Other Industrial and Agriculture	Extra Large (2000+ kW)	Large (1000-2000 kW)	Medium (500-1000 kW)	Small (100/200-500 kW) *	PG&E	SCE	SDG&E			
Very helpful	49%	31%	69%	37%	46%	44%	40%	72%	58%	52%	56%	48%	49%	39%	37%	60%	40%	165	41%	49%
Somewhat helpful	35%	49%	22%	44%	27%	31%	48%	17%	35%	36%	38%	31%	32%	34%	44%	24%	48%	149	37%	35%
Not very helpful	14%	20%	8%	17%	22%	14%	12%	11%	7%	12%	4%	15%	18%	27%	18%	12%	10%	78	19%	14%
Refused	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1	0%	0%
Don't know	2%	0%	0%	2%	4%	11%	0%	0%	0%	0%	2%	6%	2%	0%	1%	3%	0%	8	2%	2%
N	401	44	27	60	57	42	42	33	48	48	75	77	114	135	137	154	110	401	100%	100%

Barriers to Participation

BA. How significant are the following concerns about DR program participation (on a scale of 1 to 5, where 1 indicates insignificant and 5 indicates extremely significant)	Total	Business Type									Business Size				Utility			Number of Respondents	Percent of Respondents	Percent of Premises
		Office	Retail/Grocery	Institutional	Other Commercial	Transportation, Communication, Utility	Petroleum, Plastic, Rubber and Chemicals	Mining, Metals, Stone, Glass, Concrete	Electronic, Machinery, and Fabricated Metals	Other Industrial and Agriculture	Extra Large (2000+ kW)	Large (1000-2000 kW)	Medium (500-1000 kW)	Small (100/200-500 kW) *	PG&E	SCE	SDG&E			
Effects on Occupant comfort?	3.10	4.35	3.56	4.05	3.54	2.32	1.88	1.48	2.73	2.48	2.67	3.33	3.36	3.40	2.89	3.07	3.80	573	100%	100%
Effects on Production or productivity?	4.39	3.94	4.22	4.23	4.11	3.95	4.88	4.95	4.75	4.83	4.60	4.27	4.32	4.22	4.38	4.53	3.99	573	100%	100%
Need for more information on how to achieve demand reductions?	2.92	3.15	3.32	2.94	3.42	2.27	2.64	2.63	2.83	2.70	2.57	3.01	3.02	3.29	2.95	2.83	3.16	573	100%	100%
Permit regulations that limit the running of backup generators?	2.95	2.57	3.38	3.33	2.45	3.17	2.18	2.17	3.46	3.34	2.94	3.32	2.88	2.84	2.92	2.90	3.20	573	100%	100%
Amount of potential bill savings?	2.97	3.17	3.28	3.05	3.04	3.53	2.43	3.28	2.09	2.86	2.69	3.19	3.16	3.14	2.73	3.14	3.09	573	100%	100%
Risk of bill increases from level of on-peak prices and non-performance penalties?	3.80	3.41	4.03	3.82	3.83	3.53	4.19	3.88	3.72	3.88	3.91	3.56	3.77	3.79	3.59	4.01	3.70	573	100%	100%
Time and effort it takes to participate?	3.26	3.14	3.23	3.23	3.36	2.69	3.77	2.64	3.54	3.59	3.35	2.92	3.16	3.38	3.20	3.34	3.14	573	100%	100%
Inability to significantly reduce peak loads?	4.17	3.88	3.92	4.31	3.88	3.89	4.48	4.72	4.32	4.39	4.47	3.91	4.00	4.02	3.90	4.40	4.18	573	100%	100%
Length of curtailment time for indvidual events?	4.05	3.72	3.85	4.33	4.21	3.54	4.28	3.58	4.40	4.24	4.25	3.59	4.02	4.03	3.85	4.21	4.07	573	100%	100%
N	573	71	46	81	83	58	52	44	67	71	88	101	155	229	212	192	169	573	573	573

Impacts of 2005 Program Changes

CH1. How familiar is your organization with their utilitiy's Bill Protection Incentive?	Total	Business Type									Business Size				Utility			Number of Respondents	Percent of Respondents	Percent of Premises
		Office	Retail/Grocery	Institutional	Other Commercial	Transportation, Communication, Utility	Petroleum, Plastic, Rubber and Chemicals	Mining, Metals, Stone, Glass, Concrete	Electronic, Machinery, and Fabricated Metals	Other Industrial and Agriculture	Extra Large (2000+ kW)	Large (1000-2000 kW)	Medium (500-1000 kW)	Small (100/200-500 kW) *	PG&E	SCE	SDG&E			
Very familiar	11%	1%	39%	7%	15%	4%	3%	0%	8%	19%	10%	8%	13%	14%	9%	13%	12%	47	8%	11%
Somewhat familiar	33%	24%	17%	32%	25%	28%	54%	72%	42%	23%	41%	27%	29%	26%	24%	43%	26%	138	24%	33%
Not at all familiar	56%	75%	44%	62%	60%	68%	43%	28%	49%	57%	49%	65%	57%	59%	67%	44%	62%	386	67%	56%
Refused	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1	0%	0%
Don't know	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	0%	1%	0%	0%	0%	0%	0%	1	0%	0%
N	573	71	46	81	83	58	52	44	67	71	88	101	155	229	212	192	169	573	100%	100%

CH1A. To what extent does the Bill Protection Incentive address your organization's concerns about the risk of bill increases associated with the voluntary CPP program?	Total	Business Type									Business Size				Utility			Number of Respondents	Percent of Respondents	Percent of Premises
		Office	Retail/Grocery	Institutional	Other Commercial	Transportation, Communication, Utility	Petroleum, Plastic, Rubber and Chemicals	Mining, Metals, Stone, Glass, Concrete	Electronic, Machinery, and Fabricated Metals	Other Industrial and Agriculture	Extra Large (2000+ kW)	Large (1000-2000 kW)	Medium (500-1000 kW)	Small (100/200-500 kW) *	PG&E	SCE	SDG&E			
Addresses MOST of your concerns	28%	16%	66%	23%	27%	36%	18%	4%	43%	15%	26%	14%	35%	35%	22%	38%	12%	100	23%	28%
Addresses SOME of your concerns	48%	51%	23%	53%	57%	41%	66%	87%	34%	34%	53%	54%	37%	47%	42%	48%	67%	207	47%	48%
Addresses NONE of your concerns	17%	25%	10%	13%	11%	23%	14%	6%	13%	40%	14%	25%	21%	15%	27%	11%	12%	93	21%	17%
Refused	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1	0%	0%
Don't know	6%	8%	1%	11%	5%	0%	2%	2%	10%	11%	7%	6%	8%	3%	9%	3%	10%	41	9%	6%
N	442	50	34	63	65	43	39	37	53	58	66	77	121	178	166	156	120	442	100%	100%

CH1B. What concerns related to bill risk from voluntary CPP are not addressed by the Bill Protection Incentive?	Total	Business Type									Business Size				Utility			Number of Respondents	Percent of Respondents	Percent of Premises
		Office	Retail/Grocery	Institutional	Other Commercial	Transportation, Communication, Utility	Petroleum, Plastic, Rubber and Chemicals	Mining, Metals, Stone, Glass, Concrete	Electronic, Machinery, and Fabricated Metals	Other Industrial and Agriculture	Extra Large (2000+ kW)	Large (1000-2000 kW)	Medium (500-1000 kW)	Small (100/200-500 kW) *	PG&E	SCE	SDG&E			
Unable to shift load	31%	29%	42%	30%	47%	35%	11%	8%	49%	40%	21%	42%	38%	36%	37%	28%	27%	113	38%	31%
Long term concerns	17%	4%	4%	21%	19%	4%	0%	69%	7%	10%	26%	6%	17%	11%	10%	24%	16%	31	10%	17%
Need more information	17%	28%	11%	13%	25%	19%	9%	2%	13%	29%	7%	33%	18%	22%	21%	15%	14%	61	20%	17%
Cost / benefit concerns	19%	22%	22%	5%	9%	18%	69%	13%	16%	13%	26%	9%	10%	22%	19%	22%	15%	49	16%	19%
Administrative concerns	2%	3%	6%	2%	1%	2%	0%	0%	1%	2%	0%	2%	7%	1%	2%	2%	1%	9	3%	2%
Cogeneration concerns	3%	0%	0%	13%	0%	13%	0%	0%	1%	0%	7%	1%	0%	2%	3%	0%	14%	5	2%	3%
RECORD VERBATIM	2%	0%	0%	6%	2%	9%	0%	0%	0%	3%	3%	1%	6%	1%	3%	1%	3%	13	4%	2%
REFUSED	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0	0%	0%
DON'T KNOW	8%	14%	15%	9%	4%	0%	11%	9%	12%	3%	10%	7%	11%	6%	8%	8%	10%	21	7%	8%
N	300	36	19	46	46	28	27	21	36	41	47	60	72	121	116	98	86	302	101%	101%

		Business Type									Business Size				Utility					
CH2. How familiar is your organization with the changes in the Demand Bidding Program?	Total	Office	Retail/Grocery	Institutional	Other Commercial	Transportation, Communication, Utility	Petroleum, Plastic, Rubber and Chemicals	Mining, Metals, Stone, Glass, Concrete	Electronic, Machinery, and Fabricated Metals	Other Industrial and Agriculture	Extra Large (2000+ kW)	Large (1000-2000 kW)	Medium (500-1000 kW)	Small (100/200-500 kW) *	PG&E	SCE	SDG&E	Number of Respondents	Percent of Respondents	Percent of Premises
Very familiar	9%	1%	34%	6%	8%	9%	11%	1%	2%	8%	6%	5%	14%	11%	8%	11%	4%	44	8%	9%
Somewhat familiar	30%	13%	15%	35%	22%	31%	15%	70%	58%	26%	50%	20%	24%	14%	24%	38%	25%	120	21%	30%
Not at all familiar	60%	86%	51%	58%	70%	60%	74%	29%	40%	67%	44%	74%	62%	75%	69%	50%	71%	406	71%	60%
Refused	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1	0%	0%
Don't know	0%	0%	0%	1%	0%	0%	0%	0%	0%	0%	0%	0%	1%	0%	0%	0%	0%	2	0%	0%
N	573	71	46	81	83	58	52	44	67	71	88	101	155	229	212	192	169	573	100%	100%

		Business Type									Business Size				Utility					
CH2A. To what extent do the changes in the DBP program address your concerns about lack of reducible peak load at your facility?	Total	Office	Retail/Grocery	Institutional	Other Commercial	Transportation, Communication, Utility	Petroleum, Plastic, Rubber and Chemicals	Mining, Metals, Stone, Glass, Concrete	Electronic, Machinery, and Fabricated Metals	Other Industrial and Agriculture	Extra Large (2000+ kW)	Large (1000-2000 kW)	Medium (500-1000 kW)	Small (100/200-500 kW) *	PG&E	SCE	SDG&E	Number of Respondents	Percent of Respondents	Percent of Premises
Addresses MOST of your concerns	16%	19%	14%	17%	21%	17%	5%	14%	12%	18%	16%	15%	23%	11%	14%	17%	17%	79	17%	16%
Addresses SOME of your concerns	27%	31%	35%	26%	37%	16%	56%	4%	25%	16%	21%	34%	26%	34%	32%	22%	32%	157	33%	27%
Addresses NONE of your concerns	51%	33%	48%	56%	37%	59%	36%	80%	62%	54%	60%	43%	46%	47%	47%	56%	47%	201	42%	51%
Refused	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1	0%	0%
Don't know	5%	17%	2%	1%	5%	8%	2%	1%	1%	11%	3%	8%	5%	8%	7%	4%	4%	35	7%	5%
N	473	56	36	71	70	43	45	39	53	60	73	84	131	185	167	172	134	473	100%	100%

		Business Type									Business Size				Utility					
CH2B. What concerns do you have regarding the DBP program that are not addressed by the recent DBP program changes?	Total	Office	Retail/Grocery	Institutional	Other Commercial	Transportation, Communication, Utility	Petroleum, Plastic, Rubber and Chemicals	Mining, Metals, Stone, Glass, Concrete	Electronic, Machinery, and Fabricated Metals	Other Industrial and Agriculture	Extra Large (2000+ kW)	Large (1000-2000 kW)	Medium (500-1000 kW)	Small (100/200-500 kW) *	PG&E	SCE	SDG&E	Number of Respondents	Percent of Respondents	Percent of Premises
Notification concerns	9%	7%	8%	15%	19%	8%	2%	0%	6%	7%	4%	4%	22%	11%	12%	3%	19%	44	12%	9%
Length of curtailment concerns	0%	0%	0%	0%	1%	0%	0%	0%	0%	0%	0%	0%	1%	0%	0%	0%	1%	1	0%	0%
Too large of reduction required	6%	0%	5%	9%	5%	2%	2%	0%	5%	20%	9%	6%	5%	3%	10%	1%	14%	22	6%	6%
Insignificant savings	8%	0%	0%	10%	5%	2%	7%	0%	40%	0%	18%	0%	2%	1%	6%	12%	0%	9	3%	8%
Reiterates can not shift load	55%	53%	67%	56%	40%	79%	58%	96%	13%	55%	50%	52%	50%	68%	43%	70%	38%	182	51%	55%
Aggregation concerns	2%	11%	3%	0%	4%	2%	0%	0%	1%	0%	2%	3%	0%	3%	1%	2%	3%	8	2%	2%
More information required	8%	10%	9%	4%	7%	2%	17%	2%	14%	6%	7%	11%	9%	7%	13%	3%	12%	37	10%	8%
Cogeneration concerns	0%	4%	0%	0%	0%	1%	0%	0%	0%	0%	0%	3%	0%	0%	0%	0%	2%	3	1%	0%
Difficult / transparent process	2%	3%	0%	1%	2%	0%	4%	0%	6%	3%	2%	4%	1%	1%	1%	1%	7%	10	3%	2%
Other	6%	6%	7%	0%	6%	1%	12%	0%	13%	5%	7%	5%	3%	5%	11%	3%	3%	28	8%	6%
Refused	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0	0%	0%
Don't know	4%	7%	1%	6%	12%	4%	0%	2%	0%	4%	1%	8%	9%	4%	5%	4%	3%	18	5%	4%
N	358	41	27	59	58	35	35	25	40	38	56	67	94	141	134	122	102	358	101%	100%

		Business Type									Business Size				Utility					
CH3. How familiar is your organization with your utility's Technical Assistance Incentive?	Total	Office	Retail/Grocery	Institutional	Other Commercial	Transportation, Communication, Utility	Petroleum, Plastic, Rubber and Chemicals	Mining, Metals, Stone, Glass, Concrete	Electronic, Machinery, and Fabricated Metals	Other Industrial and Agriculture	Extra Large (2000+ kW)	Large (1000-2000 kW)	Medium (500-1000 kW)	Small (100/200-500 kW) *	PG&E	SCE	SDG&E	Number of Respondents	Percent of Respondents	Percent of Premises
Very familiar	9%	3%	33%	11%	12%	9%	2%	0%	3%	4%	5%	8%	13%	12%	6%	13%	6%	48	8%	9%
Somewhat familiar	31%	16%	17%	41%	20%	20%	45%	59%	42%	30%	47%	25%	20%	19%	19%	43%	25%	118	21%	31%
Not at all familiar	58%	81%	50%	47%	67%	71%	54%	40%	55%	54%	44%	66%	66%	68%	72%	43%	69%	402	70%	58%
Refused	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1	0%	0%
Don't know	2%	0%	0%	1%	0%	0%	0%	0%	0%	11%	4%	0%	1%	0%	4%	0%	0%	4	1%	2%
N	573	71	46	81	83	58	52	44	67	71	88	101	155	229	212	192	169	573	100%	100%

		Business Type									Business Size				Utility					
CH3A. To what extent does the Technical Assistance Incentive address your concerns in these areas for your facility?	Total	Office	Retail/Grocery	Institutional	Other Commercial	Transportation, Communication, Utility	Petroleum, Plastic, Rubber and Chemicals	Mining, Metals, Stone, Glass, Concrete	Electronic, Machinery, and Fabricated Metals	Other Industrial and Agriculture	Extra Large (2000+ kW)	Large (1000-2000 kW)	Medium (500-1000 kW)	Small (100/200-500 kW) *	PG&E	SCE	SDG&E	Number of Respondents	Percent of Respondents	Percent of Premises
Addresses MOST of your concerns	34%	35%	20%	47%	31%	23%	22%	23%	66%	24%	43%	35%	28%	26%	33%	32%	43%	143	32%	34%
Addresses SOME of your concerns	33%	38%	29%	33%	37%	40%	13%	63%	22%	37%	28%	40%	42%	30%	36%	30%	33%	178	40%	33%
Addresses NONE of your concerns	29%	20%	43%	19%	23%	37%	65%	12%	11%	37%	27%	26%	24%	35%	26%	36%	14%	103	23%	29%
Refused	0%	0%	0%	0%	0%	0%	0%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1	0%	0%
Don't know	4%	8%	8%	1%	9%	0%	0%	2%	1%	3%	2%	0%	5%	8%	4%	2%	10%	23	5%	4%
N	448	57	35	61	70	37	41	36	55	56	67	77	116	188	166	152	130	448	100%	100%

		Business Type									Business Size				Utility					
CH3B. What concerns do you have that are not addressed by the Technical Assistance Incentives?	Total	Office	Retail/Grocery	Institutional	Other Commercial	Transportation, Communication, Utility	Petroleum, Plastic, Rubber and Chemicals	Mining, Metals, Stone, Glass, Concrete	Electronic, Machinery, and Fabricated Metals	Other Industrial and Agriculture	Extra Large (2000+ kW)	Large (1000-2000 kW)	Medium (500-1000 kW)	Small (100/200-500 kW) *	PG&E	SCE	SDG&E	Number of Respondents	Percent of Respondents	Percent of Premises
Can not shift load	33%	29%	44%	38%	14%	12%	75%	16%	42%	24%	37%	27%	20%	38%	23%	44%	19%	72	26%	33%
Skeptical of results	18%	27%	7%	13%	19%	36%	13%	38%	25%	8%	15%	10%	25%	20%	16%	17%	29%	52	19%	18%
Cost savings	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	3	1%	0%
Not aware of program / Need more information	15%	25%	16%	11%	27%	6%	7%	1%	9%	16%	10%	25%	14%	16%	23%	8%	16%	51	18%	15%
Unsatisfactory audit / previous experince	8%	3%	5%	1%	19%	0%	2%	7%	4%	23%	13%	4%	4%	8%	10%	7%	11%	20	7%	8%
Direct access	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	0%	0%	0%	1%	0%	0%	1	0%	0%
Open to suggestions	12%	4%	7%	29%	16%	2%	0%	31%	1%	17%	16%	11%	17%	6%	19%	7%	6%	33	12%	12%
RECORD VERBATIM	6%	7%	9%	4%	2%	27%	1%	2%	7%	4%	8%	4%	11%	3%	5%	8%	6%	24	9%	6%
REFUSED	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0	0%	0%
DON'T KNOW	7%	5%	12%	4%	3%	17%	2%	4%	11%	7%	0%	20%	8%	7%	3%	9%	12%	24	9%	7%
N	281	34	24	40	40	25	28	24	29	37	41	49	75	116	100	103	78	281	100%	100%

DR Capability

		Business Type									Business Size				Utility					
CA1. What % of your afternoon peak demand could you potentially reduce for a few hours on 12 of the hottest summer days, provided you were notified the day before and given sufficient financial motivation?	Total	Office	Retail/Grocery	Institutional	Other Commercial	Transportation, Communication, Utility	Petroleum, Plastic, Rubber and Chemicals	Mining, Metals, Stone, Glass, Concrete	Electronic, Machinery, and Fabricated Metals	Other Industrial and Agriculture	Extra Large (2000+ kW)	Large (1000-2000 kW)	Medium (500-1000 kW)	Small (100/200-500 kW) *	PG&E	SCE	SDG&E	Number of Respondents	Percent of Respondents	Percent of Premises
0 percent	29%	30%	40%	24%	30%	38%	61%	3%	10%	28%	26%	29%	26%	33%	26%	33%	24%	139	24%	29%
1 to 5 percent	17%	12%	13%	24%	8%	18%	4%	9%	50%	10%	24%	11%	14%	12%	14%	18%	20%	71	12%	17%
6 to 10 percent	14%	12%	18%	26%	13%	8%	1%	2%	17%	12%	13%	21%	11%	12%	19%	8%	16%	85	15%	14%
11 to 20 percent	14%	15%	12%	9%	13%	8%	4%	67%	5%	8%	19%	6%	9%	15%	10%	18%	14%	64	11%	14%
21 to 50 percent	8%	6%	9%	7%	12%	13%	10%	3%	5%	6%	3%	11%	15%	9%	7%	10%	5%	62	11%	8%
Over 50 percent	5%	1%	2%	4%	5%	5%	3%	13%	6%	9%	5%	6%	9%	2%	6%	4%	7%	51	9%	5%
No amount of incentive would be adequate	6%	13%	2%	5%	8%	10%	4%	3%	3%	8%	3%	10%	9%	7%	7%	6%	5%	59	10%	6%
DON'T KNOW	7%	11%	4%	1%	11%	0%	13%	1%	4%	19%	6%	6%	7%	10%	11%	3%	9%	42	7%	7%
N	573	71	46	81	83	58	52	44	67	71	88	101	155	229	212	192	169	573	100%	100%

		Business Type									Business Size				Utility					
SA2. What % of your annual electricity bill would you need to save as an incentive to reduce your demand at this location by 15% for a few hours on roughly12 of the hottest summer weekdays?	Total	Office	Retail/Grocery	Institutional	Other Commercial	Transportation, Communication, Utility	Petroleum, Plastic, Rubber and Chemicals	Mining, Metals, Stone, Glass, Concrete	Electronic, Machinery, and Fabricated Metals	Other Industrial and Agriculture	Extra Large (2000+ kW)	Large (1000-2000 kW)	Medium (500-1000 kW)	Small (100/200-500 kW) *	PG&E	SCE	SDG&E	Number of Respondents	Percent of Respondents	Percent of Premises
0 percent	9%	12%	10%	17%	9%	22%	0%	2%	2%	3%	7%	14%	6%	12%	7%	10%	12%	55	10%	9%
1 to 5 percent	6%	4%	11%	3%	9%	8%	5%	4%	2%	9%	4%	8%	6%	8%	7%	4%	11%	53	9%	6%
6 to 10 percent	10%	9%	12%	20%	7%	9%	2%	0%	19%	4%	12%	12%	5%	10%	14%	6%	13%	66	12%	10%
11 to 20 percent	10%	11%	14%	12%	16%	8%	5%	11%	4%	1%	6%	9%	16%	11%	10%	9%	11%	79	14%	10%
21 to 50 percent	15%	8%	8%	8%	21%	11%	4%	61%	8%	20%	19%	3%	15%	18%	14%	20%	5%	70	12%	15%
Over 50 percent	8%	3%	0%	9%	4%	12%	3%	0%	36%	3%	12%	13%	6%	1%	3%	14%	3%	28	5%	8%
No amount of incentive would be adequate	24%	30%	38%	22%	18%	24%	30%	3%	20%	28%	21%	25%	28%	27%	27%	21%	27%	128	22%	24%
Refused	0%	0%	0%	0%	0%	5%	0%	0%	0%	0%	1%	0%	0%	0%	1%	0%	0%	1	0%	0%
DON'T KNOW	17%	23%	5%	8%	16%	2%	50%	18%	9%	32%	20%	14%	18%	14%	18%	16%	18%	93	16%	17%
N	573	71	46	81	83	58	52	44	67	71	88	101	155	229	212	192	169	573	100%	100%

		Business Type									Business Size				Utility					
CA3A. Do you have the ability to view this facility's hourly demand on an in-house energy information system?	Total	Office	Retail/Grocery	Institutional	Other Commercial	Transportation, Communication, Utility	Petroleum, Plastic, Rubber and Chemicals	Mining, Metals, Stone, Glass, Concrete	Electronic, Machinery, and Fabricated Metals	Other Industrial and Agriculture	Extra Large (2000+ kW)	Large (1000-2000 kW)	Medium (500-1000 kW)	Small (100/200-500 kW) *	PG&E	SCE	SDG&E	Number of Respondents	Percent of Respondents	Percent of Premises
Yes	31%	27%	36%	36%	34%	40%	18%	13%	23%	38%	39%	30%	30%	21%	40%	20%	38%	168	29%	31%
No	65%	69%	63%	59%	66%	48%	81%	87%	74%	51%	59%	62%	63%	75%	54%	76%	60%	386	67%	65%
Don't know	4%	4%	1%	5%	0%	12%	1%	0%	3%	11%	2%	8%	7%	4%	6%	4%	1%	19	3%	4%
N	573	71	46	81	83	58	52	44	67	71	88	101	155	229	212	192	169	573	100%	100%

		Business Type									Business Size				Utility					
CA3B. Do you have the ability to view this facilty's hourly demand on a utility provided website?	Total	Office	Retail/Grocery	Institutional	Other Commercial	Transportation, Communication, Utility	Petroleum, Plastic, Rubber and Chemicals	Mining, Metals, Stone, Glass, Concrete	Electronic, Machinery, and Fabricated Metals	Other Industrial and Agriculture	Extra Large (2000+ kW)	Large (1000-2000 kW)	Medium (500-1000 kW)	Small (100/200-500 kW) *	PG&E	SCE	SDG&E	Number of Respondents	Percent of Respondents	Percent of Premises
Yes	56%	46%	52%	55%	51%	46%	38%	84%	79%	60%	67%	56%	51%	46%	53%	60%	51%	295	51%	56%
No	31%	39%	36%	31%	46%	45%	7%	15%	19%	26%	18%	34%	36%	43%	33%	26%	38%	208	36%	31%
Don't know	13%	15%	13%	14%	3%	9%	55%	1%	3%	14%	16%	10%	13%	10%	13%	13%	11%	70	12%	13%
N	573	71	46	81	83	58	52	44	67	71	88	101	155	229	212	192	169	573	100%	100%

Automation Technology

		Business Type									Business Size				Utility					
AT1. Does the facility have an Energy Management and Control System?	Total	Office	Retail/Grocery	Institutional	Other Commercial	Transportation, Communication, Utility	Petroleum, Plastic, Rubber and Chemicals	Mining, Metals, Stone, Glass, Concrete	Electronic, Machinery, and Fabricated Metals	Other Industrial and Agriculture	Extra Large (2000+ kW)	Large (1000-2000 kW)	Medium (500-1000 kW)	Small (100/200-500 kW) *	PG&E	SCE	SDG&E	Number of Respondents	Percent of Respondents	Percent of Premises
Yes	52%	78%	55%	73%	62%	45%	59%	3%	28%	41%	57%	59%	46%	47%	55%	46%	65%	256	45%	52%
No	46%	16%	45%	26%	38%	55%	41%	97%	71%	55%	43%	41%	50%	50%	44%	52%	34%	304	53%	46%
Don't know	1%	5%	0%	1%	0%	0%	0%	0%	1%	4%	0%	0%	4%	3%	1%	2%	0%	13	2%	1%
N	573	71	46	81	83	58	52	44	67	71	88	101	155	229	212	192	169	573	100%	100%

		Business Type									Business Size				Utility					
AT1A. Which of the following systems does your EMCS control?	Total	Office	Retail/Grocery	Institutional	Other Commercial	Transportation, Communication, Utility	Petroleum, Plastic, Rubber and Chemicals	Mining, Metals, Stone, Glass, Concrete	Electronic, Machinery, and Fabricated Metals	Other Industrial and Agriculture	Extra Large (2000+ kW)	Large (1000-2000 kW)	Medium (500-1000 kW)	Small (100/200-500 kW) *	PG&E	SCE	SDG&E	Number of Respondents	Percent of Respondents	Percent of Premises
Rooftop or other distributed HVAC units	69%	79%	94%	78%	59%	44%	11%	0%	88%	79%	58%	68%	86%	77%	72%	59%	87%	187	73%	69%
Central Cooling plant	55%	69%	17%	67%	67%	44%	12%	1%	81%	57%	59%	67%	63%	34%	58%	46%	68%	150	59%	55%
Major ventilation fans	58%	66%	74%	71%	39%	51%	5%	0%	75%	68%	54%	64%	71%	52%	57%	56%	67%	147	57%	58%
Zone Temperature	60%	57%	77%	58%	67%	53%	7%	0%	81%	75%	52%	61%	73%	62%	64%	55%	61%	158	62%	60%
Lighting equipment	52%	66%	90%	43%	33%	51%	69%	0%	39%	25%	53%	36%	57%	56%	52%	55%	43%	112	44%	52%
Production processes	28%	12%	55%	6%	19%	30%	85%	99%	60%	21%	33%	23%	20%	29%	23%	38%	19%	48	19%	28%
Computer equipment	0%	0%	0%	0%	0%	0%	0%	0%	1%	0%	0%	0%	0%	0%	0%	0%	0%	1	0%	0%
Cogeneration equipment	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	0%	0%	0%	0%	0%	1	0%	0%
Other - record mention	1%	0%	0%	1%	4%	5%	0%	0%	0%	3%	2%	2%	2%	1%	2%	1%	1%	5	2%	1%
REFUSED	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0	0%	0%
DON'T KNOW	0%	0%	2%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	0%	0%	2%	1	0%	0%
N	256	55	22	54	44	18	16	3	21	23	58	57	64	77	96	77	83	256	316%	323%

		Business Type									Business Size				Utility					
AT1B. Does your EMCS offer the ability to contol all of the space temperatures on an individual zone basis?	Total	Office	Retail/Grocery	Institutional	Other Commercial	Transportation, Communication, Utility	Petroleum, Plastic, Rubber and Chemicals	Mining, Metals, Stone, Glass, Concrete	Electronic, Machinery, and Fabricated Metals	Other Industrial and Agriculture	Extra Large (2000+ kW)	Large (1000-2000 kW)	Medium (500-1000 kW)	Small (100/200-500 kW) *	PG&E	SCE	SDG&E	Number of Respondents	Percent of Respondents	Percent of Premises
Yes	63%	56%	76%	42%	81%	35%	54%	0%	86%	89%	62%	59%	68%	64%	68%	57%	66%	153	67%	63%
No	36%	43%	24%	56%	19%	60%	46%	100%	14%	11%	38%	37%	32%	35%	32%	42%	32%	74	32%	36%
Don't know	1%	1%	0%	2%	0%	5%	0%	0%	0%	0%	0%	4%	0%	1%	0%	2%	1%	3	1%	1%
N	230	54	19	53	40	14	13	1	18	18	49	51	60	70	84	72	74	230	100%	100%

		Business Type									Business Size				Utility					
AT1C. Does you EMCS offer the ability to control all of the space temperatures on a "global" basis?	Total	Office	Retail/Grocery	Institutional	Other Commercial	Transportation, Communication, Utility	Petroleum, Plastic, Rubber and Chemicals	Mining, Metals, Stone, Glass, Concrete	Electronic, Machinery, and Fabricated Metals	Other Industrial and Agriculture	Extra Large (2000+ kW)	Large (1000-2000 kW)	Medium (500-1000 kW)	Small (100/200-500 kW) *	PG&E	SCE	SDG&E	Number of Respondents	Percent of Respondents	Percent of Premises
Yes	51%	51%	37%	55%	68%	33%	22%	0%	47%	48%	53%	53%	56%	43%	51%	50%	51%	117	51%	51%
No	42%	44%	63%	43%	32%	40%	78%	100%	53%	17%	35%	37%	44%	54%	39%	44%	47%	106	46%	42%
Don't know	7%	5%	0%	2%	0%	27%	0%	0%	0%	35%	12%	9%	0%	3%	10%	6%	2%	7	3%	7%
N	230	54	19	53	40	14	13	1	18	18	49	51	60	70	84	72	74	230	100%	100%

		Business Type									Business Size				Utility					
AT2. What type of HVAC equipment controls the temperature of the occupied space(s) at your facility?	Total	Office	Retail/Grocery	Institutional	Other Commercial	Transportation, Communication, Utility	Petroleum, Plastic, Rubber and Chemicals	Mining, Metals, Stone, Glass, Concrete	Electronic, Machinery, and Fabricated Metals	Other Industrial and Agriculture	Extra Large (2000+ kW)	Large (1000-2000 kW)	Medium (500-1000 kW)	Small (100/200-500 kW) *	PG&E	SCE	SDG&E	Number of Respondents	Percent of Respondents	Percent of Premises
VAV boxes	26%	42%	2%	51%	29%	7%	1%	0%	61%	11%	37%	30%	23%	11%	27%	22%	33%	126	22%	26%
Constant volume mixing boxes	17%	12%	7%	40%	9%	13%	4%	8%	37%	11%	22%	20%	12%	12%	10%	24%	15%	73	13%	17%
Thermostat	19%	12%	20%	6%	16%	27%	55%	15%	12%	23%	20%	18%	18%	18%	16%	22%	16%	118	21%	19%
Swamp cooler	0%	0%	0%	0%	0%	0%	0%	0%	1%	0%	0%	0%	0%	0%	0%	0%	0%	3	1%	0%
A/C	2%	0%	2%	1%	0%	3%	1%	9%	0%	0%	2%	1%	3%	1%	3%	1%	1%	19	3%	2%
Electronically controlled / Computer	4%	4%	3%	3%	9%	4%	2%	0%	1%	4%	3%	2%	7%	3%	3%	4%	4%	30	5%	4%
Ammonia system	1%	0%	0%	0%	5%	0%	0%	0%	0%	1%	1%	2%	1%	0%	2%	0%	0%	5	1%	1%
Boiler	0%	0%	0%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	2	0%	0%
Chiller	1%	1%	3%	1%	2%	1%	2%	0%	0%	1%	1%	2%	3%	0%	1%	1%	1%	10	2%	1%
Fan	1%	4%	0%	0%	0%	0%	0%	0%	0%	1%	1%	1%	0%	1%	1%	0%	0%	5	1%	1%
Heater / Heat Pump	1%	1%	1%	0%	5%	2%	0%	1%	2%	0%	0%	4%	2%	2%	1%	1%	3%	15	3%	1%
Pnuematic	1%	1%	0%	8%	0%	0%	0%	0%	0%	0%	2%	1%	0%	1%	0%	1%	7%	4	1%	1%
None	6%	0%	0%	0%	1%	8%	1%	60%	0%	2%	12%	1%	2%	3%	1%	12%	1%	22	4%	6%
Rooftop	3%	6%	6%	1%	4%	0%	0%	0%	3%	1%	0%	3%	7%	3%	4%	1%	3%	14	2%	3%
Timers	1%	0%	2%	0%	5%	0%	0%	0%	1%	0%	0%	0%	0%	3%	0%	0%	6%	5	1%	1%
Package Units	2%	0%	0%	4%	0%	0%	0%	0%	0%	13%	4%	1%	0%	2%	4%	1%	0%	6	1%	2%
Carrier	0%	0%	0%	0%	0%	2%	0%	0%	0%	0%	0%	1%	0%	0%	0%	0%	0%	2	0%	0%
Other	6%	7%	4%	4%	9%	12%	3%	3%	0%	10%	3%	7%	11%	6%	8%	5%	4%	44	8%	6%
REFUSED	0%	0%	0%	0%	0%	0%	6%	0%	0%	0%	1%	0%	0%	0%	1%	0%	0%	2	0%	0%
DON'T KNOW	21%	18%	49%	6%	19%	32%	25%	3%	16%	23%	12%	21%	19%	35%	24%	19%	19%	124	22%	21%
None	573	71	46	81	83	58	52	44	67	71	88	101	155	229	212	192	169	573	110%	112%

		Business Type									Business Size				Utility					
AT2A. Is your facilty's space temperature control system primarily pnuematic, direct, digital control or some of both?	Total	Office	Retail/Grocery	Institutional	Other Commercial	Transportation, Communication, Utility	Petroleum, Plastic, Rubber and Chemicals	Mining, Metals, Stone, Glass, Concrete	Electronic, Machinery, and Fabricated Metals	Other Industrial and Agriculture	Extra Large (2000+ kW)	Large (1000-2000 kW)	Medium (500-1000 kW)	Small (100/200-500 kW) *	PG&E	SCE	SDG&E	Number of Respondents	Percent of Respondents	Percent of Premises
Pneumatic	11%	25%	4%	13%	6%	5%	5%	1%	12%	20%	10%	19%	12%	8%	15%	7%	11%	84	15%	11%
Direct digital controls	43%	31%	76%	33%	61%	51%	23%	24%	32%	47%	25%	51%	53%	57%	46%	42%	39%	267	47%	43%
Some of both	26%	33%	14%	51%	23%	20%	7%	5%	42%	18%	34%	17%	25%	20%	21%	26%	38%	134	23%	26%
REFUSED	0%	0%	0%	0%	0%	1%	1%	0%	0%	1%	0%	1%	0%	0%	0%	0%	0%	7	1%	0%
DON'T KNOW	19%	11%	6%	3%	10%	23%	65%	71%	14%	14%	31%	12%	9%	14%	17%	24%	11%	81	14%	19%
N	573	71	46	81	83	58	52	44	67	71	88	101	155	229	212	192	169	573	100%	100%

Automation Investments

		Business Type									Business Size				Utility					
EA8. In the past 2 years, has your organization considered any automation measures to iprove your ability to manage your energy use at this facility?	Total	Office	Retail/Grocery	Institutional	Other Commercial	Transportation, Communication, Utility	Petroleum, Plastic, Rubber and Chemicals	Mining, Metals, Stone, Glass, Concrete	Electronic, Machinery, and Fabricated Metals	Other Industrial and Agriculture	Extra Large (2000+ kW)	Large (1000-2000 kW)	Medium (500-1000 kW)	Small (100/200-500 kW) *	PG&E	SCE	SDG&E	Number of Respondents	Percent of Respondents	Percent of Premises
Yes	56%	52%	65%	76%	54%	34%	21%	74%	64%	49%	68%	53%	51%	46%	56%	55%	62%	272	47%	56%
No	42%	40%	35%	23%	42%	66%	78%	26%	36%	48%	31%	45%	48%	51%	41%	45%	36%	286	50%	42%
Refused	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1	0%	0%
Don't know	2%	7%	0%	1%	4%	0%	1%	0%	0%	3%	1%	3%	1%	3%	4%	1%	2%	14	2%	2%
N	573	71	46	81	83	58	52	44	67	71	88	101	155	229	212	192	169	573	100%	100%

		Business Type									Business Size				Utility					
EA9. What are the reasons why your organization considered these upgrades to your control systems?	Total	Office	Retail/Grocery	Institutional	Other Commercial	Transportation, Communication, Utility	Petroleum, Plastic, Rubber and Chemicals	Mining, Metals, Stone, Glass, Concrete	Electronic, Machinery, and Fabricated Metals	Other Industrial and Agriculture	Extra Large (2000+ kW)	Large (1000-2000 kW)	Medium (500-1000 kW)	Small (100/200-500 kW) *	PG&E	SCE	SDG&E	Number of Respondents	Percent of Respondents	Percent of Premises
Save on energy costs	74%	79%	88%	70%	86%	75%	58%	99%	48%	56%	70%	80%	74%	80%	77%	74%	69%	200	74%	74%
Upgrade old equipment	27%	21%	4%	33%	21%	12%	81%	11%	53%	40%	34%	43%	17%	12%	27%	25%	35%	78	29%	27%
Increase flexibility of controls systems	25%	30%	8%	28%	21%	24%	12%	12%	63%	11%	35%	13%	27%	11%	23%	27%	24%	59	22%	25%
Be able to respond to dynamic pricing	0%	0%	0%	0%	3%	0%	0%	0%	0%	0%	1%	0%	0%	0%	0%	1%	0%	2	1%	0%
To increase occupant comfort	6%	18%	2%	12%	5%	1%	0%	0%	0%	4%	5%	10%	3%	8%	5%	2%	20%	23	8%	6%
Energy conservation	6%	14%	9%	5%	7%	17%	0%	0%	0%	2%	4%	13%	14%	0%	7%	5%	6%	17	6%	6%
OTHER - SPECIFY	2%	3%	1%	1%	1%	7%	1%	0%	8%	2%	0%	10%	4%	2%	4%	2%	1%	12	4%	2%
REFUSED	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0	0%	0%
DON'T KNOW	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0	0%	0%
N	272	42	21	52	48	21	19	12	26	31	51	56	76	89	97	95	80	272	144%	141%

		Business Type									Business Size				Utility					
EA10. Did you actually install any of these control system upgrades for your business?	Total	Office	Retail/Grocery	Institutional	Other Commercial	Transportation, Communication, Utility	Petroleum, Plastic, Rubber and Chemicals	Mining, Metals, Stone, Glass, Concrete	Electronic, Machinery, and Fabricated Metals	Other Industrial and Agriculture	Extra Large (2000+ kW)	Large (1000-2000 kW)	Medium (500-1000 kW)	Small (100/200-500 kW) *	PG&E	SCE	SDG&E	Number of Respondents	Percent of Respondents	Percent of Premises
Yes	62%	61%	62%	51%	75%	32%	53%	84%	66%	61%	69%	52%	59%	56%	59%	67%	54%	145	53%	62%
No	38%	37%	38%	49%	25%	68%	44%	16%	34%	39%	31%	46%	41%	44%	41%	32%	46%	125	46%	38%
Don't know	0%	2%	0%	0%	0%	0%	3%	0%	0%	0%	0%	2%	0%	0%	0%	1%	0%	2	1%	0%
N	272	42	21	52	48	21	19	12	26	31	51	56	76	89	97	95	80	272	100%	100%

		Business Type									Business Size				Utility					
EA11. Which upgrades did you choose to install?	Total	Office	Retail/Grocery	Institutional	Other Commercial	Transportation, Communication, Utility	Petroleum, Plastic, Rubber and Chemicals	Mining, Metals, Stone, Glass, Concrete	Electronic, Machinery, and Fabricated Metals	Other Industrial and Agriculture	Extra Large (2000+ kW)	Large (1000-2000 kW)	Medium (500-1000 kW)	Small (100/200-500 kW) *	PG&E	SCE	SDG&E	Number of Respondents	Percent of Respondents	Percent of Premises
Controls or EMS	52%	77%	69%	77%	67%	6%	51%	5%	11%	70%	52%	58%	42%	57%	66%	39%	63%	81	56%	52%
Variable frequency drives	39%	50%	6%	48%	44%	28%	28%	99%	11%	8%	50%	41%	31%	18%	32%	44%	41%	52	36%	39%
Programmable thermostats	16%	20%	7%	41%	10%	7%	29%	0%	20%	11%	13%	31%	17%	16%	10%	17%	31%	41	28%	16%
Sensors or motion detectors	27%	23%	4%	49%	14%	32%	14%	5%	83%	7%	35%	24%	16%	19%	12%	36%	36%	33	23%	27%
Compressors	0%	0%	0%	0%	1%	0%	2%	0%	0%	2%	0%	0%	1%	1%	0%	1%	1%	4	3%	0%
Cogeneration	2%	0%	0%	0%	12%	0%	0%	0%	0%	1%	0%	11%	4%	0%	5%	0%	1%	3	2%	2%
Boiler	0%	0%	2%	0%	0%	2%	0%	0%	0%	0%	0%	0%	0%	1%	0%	0%	2%	2	1%	0%
Lighting	3%	18%	3%	3%	0%	0%	0%	0%	0%	0%	1%	0%	5%	6%	0%	2%	12%	6	4%	3%
RECORD and PROBE	6%	0%	4%	1%	4%	34%	7%	0%	12%	16%	1%	9%	14%	10%	11%	1%	9%	12	8%	6%
REFUSED	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0	0%	0%
DON'T KNOW	3%	0%	14%	4%	0%	0%	0%	0%	0%	0%	0%	0%	12%	3%	0%	5%	2%	4	3%	3%
N	145	24	14	27	28	7	12	5	10	18	30	29	43	43	58	42	45	145	164%	149%

Public Appeals Program Awareness

AP1. Do you recall receiving any alerts or notices to temporarily reduce your electricity demand during the summer of 2005?	Total	Business Type									Business Size				Utility			Number of Respondents	Percent of Respondents	Percent of Premises
		Office	Retail/Grocery	Institutional	Other Commercial	Transportation, Communication, Utility	Petroleum, Plastic, Rubber and Chemicals	Mining, Metals, Stone, Glass, Concrete	Electronic, Machinery, and Fabricated Metals	Other Industrial and Agriculture	Extra Large (2000+ kW)	Large (1000-2000 kW)	Medium (500-1000 kW)	Small (100/200-500 kW) *	PG&E	SCE	SDG&E			
Yes	41%	26%	26%	66%	38%	47%	66%	13%	27%	48%	52%	46%	40%	23%	40%	38%	49%	219	38%	41%
No	52%	68%	67%	34%	56%	50%	34%	28%	72%	51%	35%	52%	55%	72%	55%	51%	46%	332	58%	52%
Don't know	7%	6%	6%	1%	6%	3%	0%	59%	1%	1%	12%	2%	6%	4%	4%	11%	4%	22	4%	7%
N	573	71	46	81	83	58	52	44	67	71	88	101	155	229	212	192	169	573	100%	100%

AP1A. How many alerts or notices did you receive?	Total	Business Type									Business Size				Utility			Number of Respondents	Percent of Respondents	Percent of Premises
		Office	Retail/Grocery	Institutional	Other Commercial	Transportation, Communication, Utility	Petroleum, Plastic, Rubber and Chemicals	Mining, Metals, Stone, Glass, Concrete	Electronic, Machinery, and Fabricated Metals	Other Industrial and Agriculture	Extra Large (2000+ kW)	Large (1000-2000 kW)	Medium (500-1000 kW)	Small (100/200-500 kW) *	PG&E	SCE	SDG&E			
1	13%	9%	1%	24%	19%	12%	13%	0%	7%	7%	12%	10%	9%	25%	18%	5%	24%	31	14%	13%
2	26%	23%	18%	27%	6%	21%	66%	10%	17%	23%	26%	34%	20%	22%	10%	40%	26%	52	24%	26%
3	14%	20%	5%	5%	29%	11%	16%	27%	3%	19%	15%	21%	9%	6%	16%	13%	9%	38	17%	14%
4	10%	12%	2%	16%	9%	21%	0%	1%	8%	8%	6%	11%	11%	22%	5%	12%	16%	21	10%	10%
5	5%	7%	11%	0%	5%	13%	0%	0%	18%	2%	5%	6%	7%	1%	3%	4%	11%	12	5%	5%
More than 5	23%	29%	59%	22%	27%	19%	2%	62%	47%	0%	22%	8%	39%	21%	32%	19%	9%	51	23%	23%
DON'T KNOW	9%	0%	5%	6%	4%	3%	2%	0%	0%	42%	13%	10%	4%	3%	15%	7%	4%	14	6%	9%
N	219	18	15	44	33	24	21	10	29	25	51	48	58	62	81	61	77	219	100%	100%

AP1B. Did you receive the notices via email, phone, television, radio, or some other means?	Total	Business Type									Business Size				Utility			Number of Respondents	Percent of Respondents	Percent of Premises
		Office	Retail/Grocery	Institutional	Other Commercial	Transportation, Communication, Utility	Petroleum, Plastic, Rubber and Chemicals	Mining, Metals, Stone, Glass, Concrete	Electronic, Machinery, and Fabricated Metals	Other Industrial and Agriculture	Extra Large (2000+ kW)	Large (1000-2000 kW)	Medium (500-1000 kW)	Small (100/200-500 kW) *	PG&E	SCE	SDG&E			
Email	62%	53%	76%	83%	64%	35%	25%	86%	96%	53%	67%	53%	69%	50%	55%	58%	90%	147	67%	62%
Phone	23%	41%	43%	21%	29%	23%	2%	2%	25%	21%	17%	35%	40%	11%	30%	19%	17%	55	25%	23%
Television	14%	5%	17%	9%	2%	28%	0%	0%	48%	24%	12%	11%	10%	27%	10%	18%	15%	27	12%	14%
Radio	18%	9%	12%	3%	7%	35%	64%	11%	14%	14%	20%	11%	14%	22%	7%	30%	13%	32	15%	18%
Fax	2%	0%	0%	0%	2%	17%	0%	0%	0%	0%	0%	12%	0%	0%	0%	5%	0%	2	1%	2%
Mail	7%	11%	11%	5%	13%	7%	9%	0%	2%	4%	4%	4%	14%	12%	11%	5%	4%	19	9%	7%
Pager	1%	10%	0%	0%	0%	0%	0%	0%	0%	0%	2%	0%	0%	0%	2%	0%	0%	1	0%	1%
Newspaper	0%	0%	0%	0%	0%	1%	0%	0%	0%	2%	0%	0%	2%	0%	0%	1%	0%	2	1%	0%
Other- RECORD	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0	0%	0%
REFUSED	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0	0%	0%
DON'T KNOW	4%	0%	0%	0%	5%	0%	0%	2%	0%	23%	8%	0%	0%	0%	9%	1%	0%	3	1%	4%
N	219	18	15	44	33	24	21	10	29	25	51	48	58	62	81	61	77	219	132%	132%

AP1C. Were these notices associated with your Flex Your Power Now program?	Total	Business Type									Business Size				Utility			Number of Respondents	Percent of Respondents	Percent of Premises
		Office	Retail/Grocery	Institutional	Other Commercial	Transportation, Communication, Utility	Petroleum, Plastic, Rubber and Chemicals	Mining, Metals, Stone, Glass, Concrete	Electronic, Machinery, and Fabricated Metals	Other Industrial and Agriculture	Extra Large (2000+ kW)	Large (1000-2000 kW)	Medium (500-1000 kW)	Small (100/200-500 kW) *	PG&E	SCE	SDG&E			
Yes	33%	14%	50%	28%	31%	61%	9%	69%	56%	27%	26%	28%	38%	54%	34%	34%	29%	76	35%	33%
No	36%	43%	31%	44%	29%	9%	76%	3%	14%	29%	49%	26%	22%	22%	30%	47%	23%	62	28%	36%
Don't know	31%	43%	18%	28%	40%	30%	15%	28%	29%	44%	25%	46%	40%	24%	37%	19%	48%	81	37%	31%
N	219	18	15	44	33	24	21	10	29	25	51	48	58	62	81	61	77	219	100%	100%

AP1D. Upon hearing the notices, did you organization take action to temporairly reduce your electricity demand?	Total	Business Type									Business Size				Utility			Number of Respondents	Percent of Respondents	Percent of Premises
		Office	Retail/Grocery	Institutional	Other Commercial	Transportation, Communication, Utility	Petroleum, Plastic, Rubber and Chemicals	Mining, Metals, Stone, Glass, Concrete	Electronic, Machinery, and Fabricated Metals	Other Industrial and Agriculture	Extra Large (2000+ kW)	Large (1000-2000 kW)	Medium (500-1000 kW)	Small (100/200-500 kW) *	PG&E	SCE	SDG&E			
Yes	46%	57%	48%	55%	53%	29%	70%	24%	40%	21%	54%	40%	53%	22%	30%	54%	65%	102	47%	46%
No	46%	43%	52%	43%	42%	69%	30%	76%	25%	52%	32%	56%	46%	76%	52%	45%	34%	109	50%	46%
Don't know	8%	0%	0%	2%	5%	2%	0%	0%	35%	28%	14%	4%	1%	2%	17%	2%	2%	8	4%	8%
N	219	18	15	44	33	24	21	10	29	25	51	48	58	62	81	61	77	219	100%	100%

		Business Type									Business Size				Utility					
AP1E. What action did you take?	Total	Office	Retail/Grocery	Institutional	Other Commercial	Transportation, Communication, Utility	Petroleum, Plastic, Rubber and Chemicals	Mining, Metals, Stone, Glass, Concrete	Electronic, Machinery, and Fabricated Metals	Other Industrial and Agriculture	Extra Large (2000+ kW)	Large (1000-2000 kW)	Medium (500-1000 kW)	Small (100/200-500 kW) *	PG&E	SCE	SDG&E	Number of Respondents	Percent of Respondents	Percent of Premises
Turned off/reduced overheard lighting	51%	82%	78%	69%	70%	37%	7%	0%	35%	15%	39%	73%	67%	58%	60%	42%	59%	59	58%	51%
Turned off computers and other office equipment	30%	65%	23%	59%	16%	25%	0%	0%	12%	0%	34%	28%	27%	11%	20%	28%	44%	22	22%	30%
Reduced thermostat temperature setting	59%	83%	88%	37%	51%	33%	93%	0%	72%	49%	58%	62%	63%	60%	69%	65%	37%	52	51%	59%
Reduced or shut off some or all production processes	19%	25%	6%	24%	3%	10%	1%	100%	41%	50%	26%	11%	7%	6%	3%	24%	23%	22	22%	19%
Shifted Production load	1%	0%	0%	0%	0%	0%	2%	0%	3%	0%	0%	0%	0%	7%	0%	1%	1%	3	3%	1%
Enabled cogeneration	3%	0%	0%	0%	0%	31%	2%	0%	0%	3%	4%	3%	0%	2%	8%	1%	1%	3	3%	3%
Made general conservation request	16%	5%	0%	42%	10%	0%	2%	0%	2%	10%	15%	23%	12%	14%	14%	9%	32%	19	19%	16%
Record ACTION	1%	0%	0%	0%	2%	4%	0%	0%	0%	0%	1%	0%	0%	3%	0%	0%	2%	2	2%	1%
REFUSED	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0	0%	0%
DON'T KNOW	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0	0%	0%
N	102	8	9	21	17	8	11	3	17	8	28	21	29	24	32	27	43	102	178%	178%

Default CPP Awareness

		Business Type									Business Size				Utility					
DE1. How familiar is your organization with the terms of your utility proposed default CPP tariff?	Total	Office	Retail/Grocery	Institutional	Other Commercial	Transportation, Communication, Utility	Petroleum, Plastic, Rubber and Chemicals	Mining, Metals, Stone, Glass, Concrete	Electronic, Machinery, and Fabricated Metals	Other Industrial and Agriculture	Extra Large (2000+ kW)	Large (1000-2000 kW)	Medium (500-1000 kW)	Small (100/200-500 kW) *	PG&E	SCE	SDG&E	Number of Respondents	Percent of Respondents	Percent of Premises
Very Familiar	12%	3%	26%	10%	6%	11%	0%	58%	6%	5%	16%	7%	10%	12%	3%	20%	15%	38	7%	12%
Somewhat familiar	26%	27%	22%	34%	23%	20%	9%	5%	50%	28%	33%	18%	36%	15%	21%	32%	20%	135	24%	26%
Not at all familiar	59%	70%	51%	55%	70%	68%	91%	37%	45%	51%	46%	76%	53%	72%	70%	48%	64%	391	68%	59%
REFUSED	0%	0%	0%	1%	0%	0%	0%	0%	0%	0%	0%	0%	1%	0%	0%	0%	0%	1	0%	0%
DON'T KNOW	2%	0%	0%	0%	1%	1%	0%	0%	0%	16%	5%	0%	1%	1%	5%	0%	1%	8	1%	2%
N	573	71	46	81	83	58	52	44	67	71	88	101	155	229	212	192	169	573	100%	100%

		Business Type									Business Size				Utility					
DE4. Do you think that most customers' annual electricity bills would increase, decrease, or stay about the same as a result of taking service on their utility's proposed default CPP rate?	Total	Office	Retail/Grocery	Institutional	Other Commercial	Transportation, Communication, Utility	Petroleum, Plastic, Rubber and Chemicals	Mining, Metals, Stone, Glass, Concrete	Electronic, Machinery, and Fabricated Metals	Other Industrial and Agriculture	Extra Large (2000+ kW)	Large (1000-2000 kW)	Medium (500-1000 kW)	Small (100/200-500 kW) *	PG&E	SCE	SDG&E	Number of Respondents	Percent of Respondents	Percent of Premises
Increase	42%	40%	76%	57%	32%	39%	31%	1%	33%	45%	37%	51%	40%	51%	55%	32%	60%	71	41%	42%
Decrease	8%	20%	7%	4%	13%	9%	8%	6%	3%	12%	8%	9%	12%	6%	12%	7%	8%	23	13%	8%
Stay about the same	39%	29%	15%	32%	27%	7%	30%	93%	61%	29%	47%	32%	26%	36%	12%	52%	27%	52	30%	39%
DON'T KNOW	11%	12%	3%	7%	28%	45%	31%	0%	3%	13%	9%	9%	23%	7%	21%	9%	5%	27	16%	11%
N	173	21	16	29	26	22	11	7	22	19	34	31	63	45	52	67	54	173	100%	100%

		Business Type									Business Size				Utility					
DE4A. By approximately what % do you think most customer's annual electricity bills would change?	Total	Office	Retail/Grocery	Institutional	Other Commercial	Transportation, Communication, Utility	Petroleum, Plastic, Rubber and Chemicals	Mining, Metals, Stone, Glass, Concrete	Electronic, Machinery, and Fabricated Metals	Other Industrial and Agriculture	Extra Large (2000+ kW)	Large (1000-2000 kW)	Medium (500-1000 kW)	Small (100/200-500 kW) *	PG&E	SCE	SDG&E	Number of Respondents	Percent of Respondents	Percent of Premises
1	0%	0%	0%	0%	0%	0%	0%	4%	1%	0%	0%	0%	1%	0%	0%	0%	1%	2%	0%	0%
2	5%	10%	0%	16%	0%	0%	21%	0%	0%	0%	11%	0%	1%	0%	1%	0%	26%	3%	0%	5%
3	5%	8%	3%	4%	8%	0%	0%	69%	11%	0%	4%	14%	6%	3%	6%	4%	8%	8%	0%	5%
4	3%	0%	9%	0%	0%	0%	51%	0%	0%	0%	1%	6%	0%	8%	1%	5%	0%	3%	0%	3%
5	24%	37%	7%	25%	17%	29%	21%	14%	76%	0%	35%	30%	19%	5%	43%	8%	30%	21%	0%	24%
6	2%	0%	0%	0%	0%	0%	0%	0%	0%	17%	5%	0%	0%	0%	0%	5%	0%	1%	0%	2%
8	1%	0%	0%	5%	3%	0%	0%	0%	0%	0%	0%	3%	4%	0%	0%	2%	2%	4%	0%	1%
10	24%	6%	64%	15%	22%	13%	0%	4%	4%	15%	3%	26%	15%	73%	15%	35%	15%	19%	0%	24%
13	0%	0%	1%	0%	0%	0%	0%	0%	0%	0%	0%	3%	0%	0%	1%	0%	0%	1%	0%	0%
15	10%	9%	0%	32%	22%	0%	0%	0%	0%	0%	14%	14%	7%	3%	6%	14%	6%	7%	0%	10%
20	6%	2%	6%	3%	18%	29%	0%	0%	0%	0%	7%	0%	9%	2%	8%	5%	3%	6%	0%	6%
25	2%	0%	0%	0%	0%	23%	0%	0%	0%	0%	0%	0%	7%	0%	0%	3%	0%	1%	0%	2%
30	1%	0%	0%	0%	6%	0%	0%	0%	0%	0%	0%	0%	2%	0%	2%	0%	0%	1%	0%	1%
50	0%	0%	0%	0%	0%	0%	0%	10%	0%	0%	0%	0%	0%	1%	0%	0%	0%	1%	0%	0%
Don't know	17%	29%	10%	1%	4%	6%	7%	0%	8%	68%	20%	3%	28%	5%	18%	18%	9%	16%	0%	17%
N	94	13	11	16	15	10	4	5	11	9	21	18	32	23	33	30	31	94	100%	100%

		Business Type									Business Size				Utility					
DE5. Would you expect your annual electricity bill to increase or decrease as a result of taking service on your utility's proposed default CPP rate?	Total	Office	Retail/Grocery	Institutional	Other Commercial	Transportation, Communication, Utility	Petroleum, Plastic, Rubber and Chemicals	Mining, Metals, Stone, Glass, Concrete	Electronic, Machinery, and Fabricated Metals	Other Industrial and Agriculture	Extra Large (2000+ kW)	Large (1000-2000 kW)	Medium (500-1000 kW)	Small (100/200-500 kW) *	PG&E	SCE	SDG&E	Number of Respondents	Percent of Respondents	Percent of Premises
Increase	58%	44%	71%	63%	41%	59%	33%	94%	28%	61%	64%	51%	42%	61%	62%	55%	64%	79	46%	58%
Decrease	11%	19%	26%	8%	13%	15%	17%	1%	4%	11%	5%	11%	27%	11%	12%	10%	17%	33	19%	11%
Stay about the same	25%	29%	1%	24%	22%	15%	32%	5%	66%	28%	24%	37%	19%	26%	11%	33%	13%	47	27%	25%
DON'T KNOW	6%	8%	3%	6%	25%	11%	18%	1%	2%	1%	7%	0%	12%	1%	15%	3%	6%	14	8%	6%
N	173	21	16	29	26	22	11	7	22	19	34	31	63	45	52	67	54	173	100%	100%

		Business Type									Business Size				Utility					
DE5A. By approximately what % do you think your annual electricity bills would change?	Total	Office	Retail/Grocery	Institutional	Other Commercial	Transportation, Communication, Utility	Petroleum, Plastic, Rubber and Chemicals	Mining, Metals, Stone, Glass, Concrete	Electronic, Machinery, and Fabricated Metals	Other Industrial and Agriculture	Extra Large (2000+ kW)	Large (1000-2000 kW)	Medium (500-1000 kW)	Small (100/200-500 kW) *	PG&E	SCE	SDG&E	Number of Respondents	Percent of Respondents	Percent of Premises
1	1%	17%	0%	0%	0%	0%	0%	0%	0%	0%	3%	0%	0%	0%	5%	0%	0%	1	1%	1%
2	18%	10%	0%	0%	3%	0%	16%	96%	2%	0%	37%	4%	1%	0%	1%	30%	8%	7	6%	18%
3	3%	7%	2%	4%	16%	0%	9%	0%	4%	0%	2%	14%	5%	2%	4%	2%	8%	7	6%	3%
4	4%	0%	8%	0%	0%	23%	0%	1%	0%	0%	4%	2%	0%	6%	2%	5%	0%	4	4%	4%
5	15%	0%	14%	18%	12%	6%	62%	0%	66%	22%	19%	19%	18%	3%	30%	9%	11%	17	15%	15%
6	1%	0%	0%	3%	0%	0%	0%	0%	3%	0%	0%	0%	2%	1%	1%	0%	2%	3	3%	1%
7	0%	0%	0%	0%	0%	4%	0%	0%	0%	0%	0%	0%	1%	0%	0%	1%	0%	1	1%	0%
8	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	2	2%	0%
10	22%	14%	64%	29%	16%	5%	12%	0%	0%	12%	7%	32%	23%	55%	9%	25%	36%	22	20%	22%
12	1%	0%	0%	5%	0%	0%	0%	0%	0%	0%	0%	0%	0%	5%	1%	0%	4%	2	2%	1%
13	1%	0%	1%	0%	0%	0%	0%	2%	0%	0%	0%	3%	2%	0%	1%	1%	0%	2	2%	1%
15	13%	23%	5%	38%	7%	14%	0%	0%	0%	13%	13%	3%	14%	17%	19%	13%	3%	11	10%	13%
20	6%	9%	0%	2%	36%	0%	0%	0%	20%	0%	5%	20%	6%	1%	5%	2%	19%	9	8%	6%
30	1%	1%	0%	0%	5%	0%	0%	0%	0%	4%	0%	0%	5%	0%	1%	1%	1%	3	3%	1%
35	1%	0%	0%	0%	0%	15%	0%	0%	0%	0%	0%	0%	5%	0%	0%	2%	0%	1	1%	1%
40	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1	1%	0%
Don't know	12%	18%	6%	1%	6%	32%	0%	0%	5%	48%	11%	3%	18%	10%	21%	9%	7%	19	17%	12%
N	112	15	13	17	18	14	6	5	11	13	24	19	39	30	36	39	37	112	100%	100%

		Business Type									Business Size				Utility					
DE6. What kinds of information would you need in order to make an informed decision about whether to stay on default CPP?	Total	Office	Retail/Grocery	Institutional	Other Commercial	Transportation, Communication, Utility	Petroleum, Plastic, Rubber and Chemicals	Mining, Metals, Stone, Glass, Concrete	Electronic, Machinery, and Fabricated Metals	Other Industrial and Agriculture	Extra Large (2000+ kW)	Large (1000-2000 kW)	Medium (500-1000 kW)	Small (100/200-500 kW) *	PG&E	SCE	SDG&E	Number of Respondents	Percent of Respondents	Percent of Premises
CPP N/A / None	10%	1%	22%	18%	3%	28%	2%	1%	6%	6%	10%	10%	4%	14%	8%	13%	6%	42	7%	10%
Pricing information	29%	20%	6%	26%	17%	21%	62%	70%	48%	20%	45%	23%	16%	20%	23%	37%	22%	138	24%	29%
Penalty information	1%	4%	0%	0%	2%	1%	0%	1%	0%	0%	0%	1%	3%	0%	2%	0%	1%	7	1%	1%
All available program information	21%	28%	18%	23%	27%	16%	13%	10%	29%	20%	24%	12%	23%	21%	25%	15%	33%	129	23%	21%
Auditor request	1%	0%	2%	1%	0%	0%	0%	0%	0%	1%	0%	2%	1%	1%	1%	1%	1%	9	2%	1%
Generation information	1%	0%	1%	0%	0%	3%	0%	0%	1%	2%	0%	0%	3%	1%	1%	1%	0%	8	1%	1%
General impact	13%	12%	14%	13%	15%	2%	11%	10%	6%	26%	9%	15%	16%	15%	14%	13%	11%	79	14%	13%
Demand information	4%	10%	11%	1%	3%	2%	1%	1%	2%	2%	2%	6%	9%	3%	3%	5%	4%	24	4%	4%
Event information	1%	2%	1%	1%	0%	0%	1%	1%	0%	1%	1%	1%	1%	1%	1%	0%	2%	8	1%	1%
Know nothing about CPP	1%	3%	0%	2%	0%	0%	2%	0%	2%	2%	1%	2%	1%	2%	1%	1%	3%	15	3%	1%
RECORD VERBATIM	5%	1%	11%	6%	6%	4%	4%	4%	3%	3%	2%	7%	6%	6%	6%	3%	6%	22	4%	5%
REFUSED	0%	0%	0%	1%	0%	0%	0%	0%	0%	0%	0%	0%	1%	0%	0%	0%	0%	1	0%	0%
DON'T KNOW	13%	16%	12%	6%	26%	23%	5%	2%	3%	16%	6%	22%	16%	16%	16%	11%	10%	91	16%	13%
N	573	71	46	81	83	58	52	44	67	71	88	101	155	229	212	192	169	573	100%	100%

General Energy Market Perceptions

		Business Type									Business Size				Utility					
EM4. Over the next 3 years does your organization expect wholesale electricity prices to increase, decrease, or stay about the same?	Total	Office	Retail/Grocery	Institutional	Other Commercial	Transportation, Communication, Utility	Petroleum, Plastic, Rubber and Chemicals	Mining, Metals, Stone, Glass, Concrete	Electronic, Machinery, and Fabricated Metals	Other Industrial and Agriculture	Extra Large (2000+ kW)	Large (1000-2000 kW)	Medium (500-1000 kW)	Small (100/200-500 kW) *	PG&E	SCE	SDG&E	Number of Respondents	Percent of Respondents	Percent of Premises
Increase	77%	86%	80%	87%	86%	82%	84%	31%	72%	72%	74%	82%	79%	79%	77%	76%	82%	450	1%	77%
Decrease	4%	3%	4%	3%	3%	4%	10%	1%	7%	4%	3%	6%	5%	5%	7%	2%	1%	28	0%	4%
Stay about the same	15%	7%	16%	6%	9%	13%	5%	67%	19%	8%	17%	9%	15%	14%	11%	19%	11%	80	0%	15%
DON'T KNOW	4%	3%	0%	4%	1%	2%	0%	0%	2%	17%	6%	4%	1%	1%	5%	2%	5%	15	0%	4%
N	573	71	46	81	83	58	52	44	67	71	88	101	155	229	212	192	169	573	100%	100%

		Business Type									Business Size				Utility					
EM5. How likely is it that California's power supplies will be inadequate to meet expected power demand over the next three years?	Total	Office	Retail/Grocery	Institutional	Other Commercial	Transportation, Communication, Utility	Petroleum, Plastic, Rubber and Chemicals	Mining, Metals, Stone, Glass, Concrete	Electronic, Machinery, and Fabricated Metals	Other Industrial and Agriculture	Extra Large (2000+ kW)	Large (1000-2000 kW)	Medium (500-1000 kW)	Small (100/200-500 kW) *	PG&E	SCE	SDG&E	Number of Respondents	Percent of Respondents	Percent of Premises
Very likely	28%	20%	15%	36%	35%	30%	57%	18%	13%	30%	30%	31%	29%	24%	29%	29%	20%	163	28%	28%
Somewhat likely	38%	35%	60%	33%	27%	47%	31%	18%	44%	45%	37%	34%	37%	43%	36%	40%	36%	202	35%	38%
Not sure	12%	20%	11%	14%	16%	10%	5%	3%	21%	5%	10%	18%	10%	14%	17%	8%	15%	89	16%	12%
Somewhat unlikely	15%	12%	11%	14%	19%	5%	5%	58%	18%	6%	19%	13%	15%	12%	12%	17%	21%	72	13%	15%
Very unlikely	5%	11%	3%	1%	2%	9%	2%	3%	4%	8%	3%	2%	8%	6%	4%	4%	7%	36	6%	5%
REFUSED	0%	0%	0%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1	0%	0%
DON'T KNOW	1%	1%	0%	2%	0%	0%	0%	0%	0%	5%	1%	3%	0%	2%	2%	1%	0%	10	2%	1%
N	573	71	46	81	83	58	52	44	67	71	88	101	155	229	212	192	169	573	100%	100%

Firmographics

EC1. What is the main activity performed at this location?	Total	Business Type									Business Size				Utility			Number of Respondents	Percent of Respondents	Percent of Premises
		Office	Retail/Grocery	Institutional	Other Commercial	Transportation, Communication, Utility	Petroleum, Plastic, Rubber and Chemicals	Mining, Metals, Stone, Glass, Concrete	Electronic, Machinery, and Fabricated Metals	Other Industrial and Agriculture	Extra Large (2000+ kW)	Large (1000-2000 kW)	Medium (500-1000 kW)	Small (100/200-500 kW) *	PG&E	SCE	SDG&E			
Office	10%	60%	1%	7%	1%	10%	0%	0%	4%	5%	5%	21%	17%	8%	13%	9%	8%	65	12%	10%
Retail (non-food)	2%	6%	14%	0%	0%	0%	0%	0%	0%	0%	1%	4%	3%	3%	2%	1%	6%	13	2%	2%
College/university	4%	0%	1%	25%	0%	4%	0%	0%	0%	0%	7%	6%	1%	2%	5%	5%	4%	17	3%	4%
School	4%	0%	0%	23%	0%	0%	0%	0%	0%	0%	2%	0%	2%	9%	3%	4%	3%	25	4%	4%
Grocery store	4%	0%	35%	1%	0%	0%	0%	0%	0%	0%	0%	0%	1%	14%	3%	6%	1%	7	1%	4%
Restaurant	2%	3%	2%	0%	8%	0%	0%	0%	0%	1%	0%	3%	0%	4%	0%	2%	7%	7	1%	2%
Health care/hospital	7%	4%	0%	34%	5%	0%	0%	0%	0%	1%	9%	7%	6%	4%	3%	4%	24%	34	6%	7%
Hotel or motel	2%	2%	0%	0%	16%	0%	0%	0%	0%	0%	1%	6%	4%	1%	2%	2%	6%	19	3%	2%
Warehouse	4%	6%	9%	0%	13%	5%	2%	0%	1%	0%	2%	3%	10%	4%	5%	4%	3%	33	6%	4%
Personal Service	2%	3%	3%	1%	4%	1%	0%	0%	5%	0%	0%	2%	3%	4%	3%	0%	4%	12	2%	2%
Community Service/Church/Temple/Municipality	2%	9%	0%	6%	1%	1%	0%	0%	0%	0%	2%	0%	3%	4%	0%	3%	7%	19	3%	2%
Industrial Electronic & Machinery	5%	3%	0%	1%	2%	0%	4%	1%	21%	11%	2%	5%	8%	6%	2%	6%	6%	41	7%	5%
Industrial Mining. Metals. Stone. Glass, Concrete	2%	0%	0%	0%	0%	0%	1%	12%	6%	2%	2%	1%	3%	2%	2%	3%	0%	27	5%	2%
Industrial Petroleum, Plastic, Rubber and Chemicals	9%	0%	0%	0%	0%	1%	40%	58%	0%	10%	19%	4%	3%	1%	9%	12%	0%	27	5%	9%
Other Industrial	19%	4%	18%	2%	12%	34%	5%	16%	53%	30%	21%	16%	17%	17%	23%	17%	11%	103	18%	19%
Agricultural	6%	0%	6%	0%	21%	3%	0%	0%	1%	18%	5%	5%	8%	7%	9%	5%	2%	33	6%	6%
Transportation/Telecommunications/Utility	4%	0%	5%	0%	3%	36%	0%	0%	1%	0%	7%	2%	3%	3%	4%	5%	5%	22	4%	4%
Manufacturing	8%	0%	1%	0%	3%	0%	45%	13%	9%	19%	12%	10%	6%	4%	6%	12%	3%	48	8%	8%
Entertainment / Media	3%	0%	5%	0%	11%	4%	0%	0%	0%	3%	4%	0%	3%	2%	4%	2%	1%	12	2%	3%
Other SPECIFY	0%	0%	0%	0%	0%	0%	3%	0%	0%	0%	0%	2%	0%	0%	1%	0%	0%	1	0%	0%
N	565	69	45	81	83	56	52	43	67	69	88	100	152	225	210	190	165	565	100%	100%

EC2. Approximately how many square feet does your organization occupy at this facility?	Total	Business Type									Business Size				Utility			Number of Respondents	Percent of Respondents	Percent of Premises
		Office	Retail/Grocery	Institutional	Other Commercial	Transportation, Communication, Utility	Petroleum, Plastic, Rubber and Chemicals	Mining, Metals, Stone, Glass, Concrete	Electronic, Machinery, and Fabricated Metals	Other Industrial and Agriculture	Extra Large (2000+ kW)	Large (1000-2000 kW)	Medium (500-1000 kW)	Small (100/200-500 kW) *	PG&E	SCE	SDG&E			
Less than 10,000 square feet	6%	6%	5%	1%	7%	25%	0%	2%	2%	6%	1%	7%	3%	13%	6%	4%	9%	47	8%	6%
10,000 but less than 20,000 square ft.	4%	2%	6%	1%	8%	4%	2%	2%	3%	3%	0%	1%	3%	9%	2%	2%	13%	45	8%	4%
20,000 but less than 50,000 square ft.	16%	11%	46%	12%	7%	13%	8%	11%	17%	13%	7%	5%	9%	37%	14%	17%	15%	99	17%	16%
50,000 but less than 100,000 square ft.	12%	18%	15%	6%	14%	7%	15%	10%	14%	11%	4%	13%	22%	17%	15%	11%	8%	83	14%	12%
100,000 but less than 200,000 square ft.	15%	16%	8%	10%	14%	13%	9%	1%	52%	12%	13%	21%	21%	12%	13%	18%	12%	80	14%	15%
200,000 but less than 300,000 square ft.	7%	13%	2%	6%	15%	5%	1%	2%	4%	9%	4%	10%	18%	2%	10%	5%	5%	44	8%	7%
300,000 but less than 400,000 square ft.	8%	5%	12%	8%	4%	2%	40%	0%	2%	5%	11%	14%	6%	1%	3%	13%	3%	30	5%	8%
400,000 but less than 500,000 square ft.	5%	0%	0%	10%	7%	0%	0%	3%	0%	21%	12%	5%	1%	0%	8%	2%	9%	19	3%	5%
Over 500,000 square feet	16%	24%	4%	41%	19%	14%	4%	2%	5%	13%	29%	19%	9%	2%	16%	14%	23%	75	13%	16%
Ag/Nonfacility - Outdoors	9%	0%	0%	2%	2%	16%	17%	59%	0%	5%	17%	3%	4%	4%	6%	13%	1%	31	5%	9%
DON'T KNOW	3%	5%	1%	1%	4%	2%	4%	8%	1%	3%	2%	3%	4%	3%	6%	0%	1%	20	3%	3%
N	573	71	46	81	83	58	52	44	67	71	88	101	155	229	212	192	169	573	100%	100%

EC3. Does your organization…..	Total	Business Type									Business Size				Utility			Number of Respondents	Percent of Respondents	Percent of Premises
		Office	Retail/Grocery	Institutional	Other Commercial	Transportation, Communication, Utility	Petroleum, Plastic, Rubber and Chemicals	Mining, Metals, Stone, Glass, Concrete	Electronic, Machinery, and Fabricated Metals	Other Industrial and Agriculture	Extra Large (2000+ kW)	Large (1000-2000 kW)	Medium (500-1000 kW)	Small (100/200-500 kW) *	PG&E	SCE	SDG&E			
Own this space	63%	67%	40%	93%	77%	73%	65%	35%	26%	67%	64%	68%	68%	56%	70%	54%	73%	382	67%	63%
Lease this space	27%	30%	60%	5%	18%	24%	24%	7%	40%	32%	13%	29%	32%	40%	25%	28%	25%	170	30%	27%
Own a portion and lease the remainder	10%	2%	0%	1%	4%	0%	10%	58%	33%	0%	22%	3%	0%	3%	3%	18%	2%	15	3%	10%
REFUSED	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1	0%	0%
DON'T KNOW	1%	1%	0%	1%	0%	3%	0%	0%	0%	1%	0%	1%	0%	1%	1%	0%	0%	5	1%	1%
N	573	71	46	81	83	58	52	44	67	71	88	101	155	229	212	192	169	573	100%	100%

EC5. What % of our organization's total annual operating costs do energy costs represent?	Total	Business Type									Business Size				Utility			Number of Respondents	Percent of Respondents	Percent of Premises
		Office	Retail/Grocery	Institutional	Other Commercial	Transportation, Communication, Utility	Petroleum, Plastic, Rubber and Chemicals	Mining, Metals, Stone, Glass, Concrete	Electronic, Machinery, and Fabricated Metals	Other Industrial and Agriculture	Extra Large (2000+ kW)	Large (1000-2000 kW)	Medium (500-1000 kW)	Small (100/200-500 kW) *	PG&E	SCE	SDG&E			
Less than 1 percent	5%	2%	6%	8%	4%	10%	2%	0%	3%	8%	5%	3%	9%	4%	4%	7%	3%	33	6%	5%
1 to 4 percent	14%	9%	22%	23%	15%	13%	13%	0%	6%	17%	5%	23%	15%	21%	20%	12%	8%	93	16%	14%
5 to 10 percent	26%	25%	16%	20%	25%	34%	47%	13%	52%	10%	35%	18%	22%	19%	19%	30%	30%	138	24%	26%
11 TO 25 percent	18%	11%	29%	5%	7%	12%	17%	73%	10%	20%	24%	13%	8%	20%	14%	24%	10%	84	15%	18%
over 25 percent	9%	10%	7%	7%	9%	12%	10%	2%	5%	17%	9%	11%	9%	8%	14%	4%	9%	54	9%	9%
REFUSED	0%	0%	2%	0%	0%	0%	0%	0%	2%	0%	0%	0%	1%	1%	0%	1%	0%	2	0%	0%
DON'T KNOW	28%	43%	18%	36%	40%	19%	11%	12%	22%	28%	22%	33%	35%	27%	29%	23%	40%	169	29%	28%
N	573	71	46	81	83	58	52	44	67	71	88	101	155	229	212	192	169	573	100%	100%

		Business Type									Business Size				Utility					
EC5A. Has your organization assigned responsibility for controlling energy usage and costs to any of the following?	Total	Office	Retail/Grocery	Institutional	Other Commercial	Transportation, Communication, Utility	Petroleum, Plastic, Rubber and Chemicals	Mining, Metals, Stone, Glass, Concrete	Electronic, Machinery, and Fabricated Metals	Other Industrial and Agriculture	Extra Large (2000+ kW)	Large (1000-2000 kW)	Medium (500-1000 kW)	Small (100/200-500 kW) *	PG&E	SCE	SDG&E	Number of Respondents	Percent of Respondents	Percent of Premises
An in-house staff person	43%	56%	40%	42%	45%	32%	67%	21%	38%	46%	38%	47%	51%	43%	55%	32%	46%	270	47%	43%
a group of staff	32%	20%	37%	44%	23%	20%	5%	73%	41%	24%	46%	19%	24%	24%	20%	44%	26%	126	22%	32%
an outside contractor	2%	0%	0%	2%	3%	1%	2%	0%	4%	1%	0%	7%	1%	1%	2%	2%	1%	13	2%	2%
no one	23%	22%	24%	12%	27%	47%	26%	6%	17%	28%	16%	23%	24%	31%	22%	23%	27%	161	28%	23%
DON'T KNOW	1%	1%	0%	0%	3%	0%	0%	0%	0%	0%	0%	3%	0%	0%	1%	0%	0%	3	1%	1%
N	573	71	46	81	83	58	52	44	67	71	88	101	155	229	212	192	169	573	100%	100%

		Business Type									Business Size				Utility					
EC6. Approximately how many locations does your organization have in California?	Total	Office	Retail/Grocery	Institutional	Other Commercial	Transportation, Communication, Utility	Petroleum, Plastic, Rubber and Chemicals	Mining, Metals, Stone, Glass, Concrete	Electronic, Machinery, and Fabricated Metals	Other Industrial and Agriculture	Extra Large (2000+ kW)	Large (1000-2000 kW)	Medium (500-1000 kW)	Small (100/200-500 kW) *	PG&E	SCE	SDG&E	Number of Respondents	Percent of Respondents	Percent of Premises
1	36%	36%	22%	35%	44%	33%	31%	23%	65%	31%	36%	39%	42%	31%	38%	38%	24%	240	42%	36%
2 to 4	22%	17%	17%	5%	30%	39%	18%	12%	27%	36%	20%	33%	25%	18%	29%	18%	17%	132	23%	22%
5 to 10	20%	23%	14%	18%	9%	8%	40%	64%	5%	18%	33%	12%	11%	13%	13%	25%	22%	80	14%	20%
11 to 25	10%	11%	26%	14%	7%	8%	10%	0%	0%	13%	7%	10%	4%	20%	10%	9%	16%	49	9%	10%
Over 25	10%	12%	21%	26%	9%	8%	0%	1%	1%	2%	5%	5%	15%	17%	9%	9%	19%	61	11%	10%
REFUSED	0%	0%	0%	2%	0%	0%	0%	0%	0%	0%	0%	0%	1%	0%	0%	0%	1%	2	0%	0%
DON'T KNOW	1%	1%	0%	0%	1%	3%	1%	0%	3%	0%	0%	3%	2%	0%	2%	0%	2%	9	2%	1%
N	573	71	46	81	83	58	52	44	67	71	88	101	155	229	212	192	169	573	100%	100%

		Business Type									Business Size				Utility					
EC7. What is the approximate number of full-time equivalent workers of all types employed by your organization at this facility?	Total	Office	Retail/Grocery	Institutional	Other Commercial	Transportation, Communication, Utility	Petroleum, Plastic, Rubber and Chemicals	Mining, Metals, Stone, Glass, Concrete	Electronic, Machinery, and Fabricated Metals	Other Industrial and Agriculture	Extra Large (2000+ kW)	Large (1000-2000 kW)	Medium (500-1000 kW)	Small (100/200-500 kW) *	PG&E	SCE	SDG&E	Number of Respondents	Percent of Respondents	Percent of Premises
1 to 10	10%	33%	11%	0%	5%	22%	20%	0%	1%	4%	4%	12%	11%	17%	14%	6%	11%	73	13%	10%
11 to 50	14%	22%	14%	3%	24%	36%	14%	7%	4%	10%	11%	12%	11%	22%	19%	10%	15%	144	25%	14%
51 to 100	13%	8%	37%	6%	13%	9%	8%	15%	16%	8%	6%	8%	16%	24%	15%	13%	8%	74	13%	13%
100 to 250	24%	24%	18%	15%	16%	14%	55%	18%	21%	40%	18%	30%	26%	26%	23%	25%	20%	135	24%	24%
251 to 500	16%	5%	12%	19%	18%	3%	4%	1%	50%	20%	20%	18%	21%	6%	13%	18%	15%	61	11%	16%
501 to 1000	6%	3%	0%	11%	10%	1%	0%	0%	4%	14%	10%	8%	4%	1%	7%	4%	8%	35	6%	6%
Or, over 1000	11%	2%	3%	46%	15%	4%	0%	0%	3%	2%	20%	11%	4%	1%	7%	10%	21%	40	7%	11%
REFUSED	0%	1%	0%	1%	1%	1%	0%	0%	0%	0%	0%	0%	2%	0%	0%	0%	2%	4	1%	0%
DON'T KNOW	6%	0%	6%	0%	0%	9%	0%	58%	0%	1%	12%	0%	5%	3%	1%	12%	0%	7	1%	6%
N	573	71	46	81	83	58	52	44	67	71	88	101	155	229	212	192	169	573	100%	100%

		Business Type									Business Size				Utility					
EC9A. Which of the following is the largest end use in terms of electricity consumption at this facility?	Total	Office	Retail/Grocery	Institutional	Other Commercial	Transportation, Communication, Utility	Petroleum, Plastic, Rubber and Chemicals	Mining, Metals, Stone, Glass, Concrete	Electronic, Machinery, and Fabricated Metals	Other Industrial and Agriculture	Extra Large (2000+ kW)	Large (1000-2000 kW)	Medium (500-1000 kW)	Small (100/200-500 kW) *	PG&E	SCE	SDG&E	Number of Respondents	Percent of Respondents	Percent of Premises
Lighting	14%	34%	26%	29%	10%	12%	0%	0%	2%	1%	7%	13%	23%	19%	13%	14%	22%	90	16%	14%
HVAC	27%	47%	16%	62%	38%	2%	1%	1%	30%	9%	27%	30%	24%	27%	27%	20%	50%	157	28%	27%
Continuous processing	32%	13%	17%	5%	17%	41%	73%	28%	58%	64%	43%	32%	24%	23%	33%	36%	20%	176	31%	32%
Batch processing	4%	0%	3%	1%	2%	13%	7%	5%	4%	5%	0%	2%	7%	8%	5%	3%	2%	49	9%	4%
Refrigeration	10%	3%	33%	1%	28%	8%	5%	0%	0%	12%	5%	12%	13%	15%	13%	11%	3%	50	9%	10%
Pumps / Compressors	7%	0%	0%	0%	4%	7%	13%	58%	2%	1%	14%	1%	4%	2%	3%	12%	1%	16	3%	7%
Computers	1%	0%	0%	2%	0%	8%	0%	0%	1%	0%	0%	5%	1%	1%	1%	2%	1%	5	1%	1%
Motors	1%	0%	1%	0%	0%	0%	0%	8%	0%	3%	2%	1%	2%	0%	2%	1%	0%	6	1%	1%
Machinery	2%	0%	5%	1%	1%	8%	1%	0%	3%	3%	0%	4%	3%	3%	2%	2%	0%	14	2%	2%
DON'T KNOW	1%	3%	1%	0%	1%	0%	0%	0%	0%	1%	1%	0%	0%	1%	1%	0%	1%	5	1%	1%
N	568	71	46	81	82	56	52	43	67	70	86	100	153	229	208	191	169	568	100%	100%

		Business Type									Business Size				Utility					
EC9B. Which of the following is the second largest end use in terms of electricity consumption at this facility?	Total	Office	Retail/Grocery	Institutional	Other Commercial	Transportation, Communication, Utility	Petroleum, Plastic, Rubber and Chemicals	Mining, Metals, Stone, Glass, Concrete	Electronic, Machinery, and Fabricated Metals	Other Industrial and Agriculture	Extra Large (2000+ kW)	Large (1000-2000 kW)	Medium (500-1000 kW)	Small (100/200-500 kW) *	PG&E	SCE	SDG&E	Number of Respondents	Percent of Respondents	Percent of Premises
Lighting	43%	45%	50%	52%	36%	37%	27%	75%	23%	39%	45%	51%	32%	43%	36%	50%	41%	237	41%	43%
HVAC	20%	35%	19%	30%	19%	29%	7%	9%	14%	12%	12%	18%	27%	29%	20%	17%	33%	144	25%	20%
Continuous processing	7%	6%	0%	6%	12%	0%	8%	0%	18%	6%	7%	9%	7%	5%	12%	1%	10%	43	8%	7%
Batch processing	13%	0%	5%	0%	11%	2%	45%	4%	41%	24%	21%	10%	8%	8%	10%	19%	2%	54	9%	13%
Refrigeration	6%	2%	5%	9%	13%	3%	3%	0%	0%	9%	6%	5%	5%	6%	9%	3%	6%	22	4%	6%
OTHER - SPECIFY	7%	4%	20%	2%	8%	21%	0%	3%	3%	5%	3%	7%	20%	5%	5%	9%	7%	50	9%	7%
REFUSED	1%	3%	1%	0%	1%	0%	0%	0%	0%	3%	1%	1%	1%	1%	1%	1%	1%	9	2%	1%
DON'T KNOW	3%	4%	1%	0%	1%	9%	10%	8%	0%	2%	6%	0%	1%	3%	7%	1%	1%	13	2%	3%
N	572	71	46	81	82	58	52	44	67	71	87	101	155	229	211	192	169	572	100%	100%

EC10. Does this site have any on-site electricity generators?	Total	Business Type: Office	Retail/Grocery	Institutional	Other Commercial	Transportation, Communication, Utility	Petroleum, Plastic, Rubber and Chemicals	Mining, Metals, Stone, Glass, Concrete	Electronic, Machinery, and Fabricated Metals	Other Industrial and Agriculture	Business Size: Extra Large (2000+ kW)	Large (1000-2000 kW)	Medium (500-1000 kW)	Small (100/200-500 kW) *	Utility: PG&E	SCE	SDG&E	Number of Respondents	Percent of Respondents	Percent of Premises
Yes,for backup/standby purposes only	43%	63%	47%	48%	37%	55%	8%	18%	57%	34%	52%	49%	39%	29%	45%	38%	51%	195	34%	43%
Yes,everyday supplement/replacement	6%	0%	0%	13%	7%	12%	7%	1%	1%	10%	9%	7%	3%	2%	10%	3%	3%	37	6%	6%
No	51%	36%	53%	39%	55%	33%	85%	81%	42%	54%	38%	44%	57%	67%	44%	59%	44%	336	59%	51%
REFUSED	0%	0%	0%	0%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1	0%	0%
DON'T KNOW	0%	1%	0%	1%	0%	0%	0%	0%	1%	1%	0%	0%	0%	1%	1%	0%	1%	4	1%	0%
N	573	71	46	81	83	58	52	44	67	71	88	101	155	229	212	192	169	573	100%	100%

EC10A. What percent of this location's electricity load can be met by your on-site generation?	Total	Business Type: Office	Retail/Grocery	Institutional	Other Commercial	Transportation, Communication, Utility	Petroleum, Plastic, Rubber and Chemicals	Mining, Metals, Stone, Glass, Concrete	Electronic, Machinery, and Fabricated Metals	Other Industrial and Agriculture	Business Size: Extra Large (2000+ kW)	Large (1000-2000 kW)	Medium (500-1000 kW)	Small (100/200-500 kW) *	Utility: PG&E	SCE	SDG&E	Number of Respondents	Percent of Respondents	Percent of Premises
0	2%	3%	0%	1%	1%	1%	0%	1%	2%	5%	1%	4%	1%	1%	1%	3%	0%	8	3%	2%
1	5%	4%	0%	8%	8%	5%	5%	0%	0%	10%	4%	6%	10%	3%	6%	2%	10%	13	6%	5%
2	2%	4%	0%	1%	0%	0%	6%	0%	2%	6%	0%	3%	2%	5%	2%	2%	1%	7	3%	2%
3	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	0%	0%	1%	0%	0%	0%	1%	1	0%	0%
4	1%	5%	0%	0%	0%	0%	1%	0%	0%	0%	2%	0%	0%	0%	2%	0%	0%	2	1%	1%
5	3%	4%	5%	5%	3%	0%	1%	10%	3%	1%	2%	2%	8%	4%	1%	6%	5%	18	8%	3%
10	16%	26%	7%	0%	1%	1%	1%	0%	53%	33%	22%	7%	9%	15%	12%	23%	8%	22	9%	16%
15	2%	1%	0%	5%	0%	0%	0%	0%	9%	0%	3%	1%	3%	0%	1%	2%	6%	6	3%	2%
20	9%	12%	54%	1%	4%	0%	5%	0%	0%	0%	2%	5%	8%	28%	6%	14%	2%	11	5%	9%
25	5%	3%	0%	1%	2%	3%	0%	43%	17%	0%	7%	2%	2%	3%	8%	2%	1%	8	3%	5%
30	2%	5%	0%	1%	6%	1%	0%	0%	0%	0%	0%	1%	9%	2%	3%	1%	2%	7	3%	2%
33	1%	0%	2%	4%	0%	0%	4%	0%	0%	0%	2%	0%	2%	0%	0%	2%	2%	3	1%	1%
40	1%	0%	0%	2%	2%	0%	0%	0%	0%	0%	1%	0%	2%	0%	1%	0%	0%	2	1%	1%
45	0%	0%	1%	0%	0%	0%	0%	0%	0%	0%	0%	1%	0%	0%	0%	0%	0%	1	0%	0%
50	8%	0%	1%	7%	9%	9%	11%	0%	12%	18%	6%	10%	3%	12%	12%	3%	8%	18	8%	8%
60	2%	0%	0%	0%	9%	2%	14%	0%	0%	1%	2%	4%	0%	1%	1%	1%	5%	7	3%	2%
65	1%	0%	0%	0%	0%	0%	0%	0%	0%	5%	0%	3%	0%	0%	1%	0%	0%	1	0%	1%
66	1%	0%	0%	0%	3%	6%	0%	0%	0%	0%	2%	0%	0%	0%	2%	1%	0%	2	1%	1%
67	0%	0%	0%	0%	0%	0%	0%	3%	0%	0%	0%	1%	0%	0%	0%	0%	0%	1	0%	0%
70	3%	3%	5%	0%	21%	0%	0%	0%	0%	0%	4%	9%	0%	0%	7%	1%	0%	4	2%	3%
73	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1	0%	0%
75	1%	4%	0%	0%	3%	0%	0%	0%	0%	0%	1%	1%	3%	0%	1%	1%	0%	3	1%	1%
80	4%	0%	0%	11%	0%	1%	38%	0%	0%	11%	8%	0%	4%	0%	6%	5%	0%	6	3%	4%
85	0%	0%	0%	1%	0%	0%	0%	0%	0%	0%	0%	0%	1%	0%	0%	0%	0%	1	0%	0%
90	2%	0%	0%	10%	0%	0%	0%	0%	0%	1%	2%	2%	2%	0%	2%	0%	8%	6	3%	2%
95	0%	0%	0%	1%	0%	1%	7%	0%	0%	0%	0%	2%	1%	0%	0%	1%	0%	3	1%	0%
97	1%	0%	0%	3%	0%	0%	0%	0%	0%	0%	1%	0%	0%	0%	0%	2%	0%	1	0%	1%
98	2%	0%	0%	10%	0%	0%	0%	0%	0%	0%	4%	0%	0%	0%	0%	0%	12%	1	0%	2%
100	12%	1%	0%	14%	15%	49%	6%	0%	0%	11%	9%	20%	13%	12%	8%	19%	8%	35	15%	12%
130	0%	0%	0%	0%	2%	0%	0%	0%	1%	0%	0%	1%	1%	0%	0%	0%	2%	2	1%	0%
150	0%	0%	0%	0%	0%	2%	0%	0%	0%	0%	0%	2%	0%	0%	0%	0%	2%	1	0%	0%
300	0%	0%	0%	0%	0%	0%	0%	0%	2%	0%	1%	0%	0%	0%	0%	0%	2%	1	0%	0%
800	0%	0%	0%	0%	0%	2%	0%	0%	0%	0%	0%	1%	0%	0%	0%	0%	0%	1	0%	0%
5000	1%	0%	0%	0%	0%	7%	0%	0%	0%	0%	2%	0%	0%	0%	2%	0%	0%	1	0%	1%
Don't know	12%	23%	26%	11%	11%	10%	3%	42%	0%	0%	11%	13%	16%	14%	15%	9%	15%	27	12%	12%
N	232	41	13	45	35	33	15	10	15	25	60	57	58	57	95	72	65	232	100%	100%

EC10B. Are thre legal restrictions on the number of hours your on-site system can run during the summer?	Total	Business Type: Office	Retail/Grocery	Institutional	Other Commercial	Transportation, Communication, Utility	Petroleum, Plastic, Rubber and Chemicals	Mining, Metals, Stone, Glass, Concrete	Electronic, Machinery, and Fabricated Metals	Other Industrial and Agriculture	Business Size: Extra Large (2000+ kW)	Large (1000-2000 kW)	Medium (500-1000 kW)	Small (100/200-500 kW) *	Utility: PG&E	SCE	SDG&E	Number of Respondents	Percent of Respondents	Percent of Premises
Yes	68%	54%	77%	68%	61%	57%	57%	96%	93%	66%	76%	66%	67%	51%	64%	69%	76%	130	56%	68%
No	26%	36%	8%	30%	28%	43%	37%	4%	4%	32%	22%	26%	28%	36%	28%	27%	18%	83	36%	26%
Refused	0%	0%	0%	0%	1%	0%	0%	0%	0%	0%	0%	0%	0%	1%	0%	0%	1%	1	0%	0%
Don't know	6%	10%	15%	2%	10%	0%	6%	0%	3%	2%	2%	8%	5%	13%	7%	3%	5%	18	8%	6%
N	232	41	13	45	35	33	15	10	15	25	60	57	58	57	95	72	65	232	100%	100%

C2. 2005 CPP and DBP Participant Survey Results

2005 Post-Event and End of Summer Participant Survey Results (combined)

INTRODUCTION

SC3. Are you responsible for multiple facilities in the [UTILITY] service territory that are signed up for CPP?	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
Yes	40%	42%	0%	48%	42%	0%	0%	42%	28%	47%	40%	42%	34%	0%	46%	21%	66%	40%	36%	42%	28%
No	60%	58%	100%	52%	58%	0%	0%	58%	72%	53%	60%	58%	66%	100%	54%	79%	34%	60%	64%	58%	72%
N	99	67	5	27	68	0	0	17	14	15	27	39	17	1	38	37	24	99	31	17	14

SC4. Are you responsible for multiple facilities in the [UTILITY] service territory that are signed up for DBP?	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
Yes	28%	27%	27%	53%	0%	28%	26%	42%	36%	28%	23%	30%	31%	0%	29%	22%	41%	39%	28%	31%	27%
No	72%	73%	73%	48%	0%	72%	74%	58%	64%	72%	77%	70%	69%	0%	71%	78%	59%	61%	72%	69%	73%
N	230	100	117	13	0	63	136	17	14	71	63	72	24	0	66	121	43	31	230	80	150

PARTICIPATION SUMMARY

ES1. Thinking back over the summer (May-Present), how many events would you say were called for the CPP program?	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
0	1%	2%	0%	0%	0%	0%	0%	9%	0%	0%	0%	3%	0%	0%	4%	0%	0%	1%	5%	9%	0%
1	1%	2%	0%	0%	0%	0%	0%	0%	9%	0%	0%	3%	0%	0%	0%	3%	0%	1%	4%	0%	9%
2	5%	3%	33%	6%	4%	0%	0%	9%	9%	16%	5%	4%	0%	0%	0%	8%	9%	5%	9%	9%	9%
3	8%	2%	0%	31%	9%	0%	0%	9%	0%	6%	5%	14%	0%	0%	12%	0%	14%	8%	5%	9%	0%
4	4%	5%	0%	0%	4%	0%	0%	0%	9%	0%	0%	4%	14%	0%	0%	10%	0%	4%	4%	0%	9%
5	11%	8%	0%	25%	15%	0%	0%	0%	0%	15%	11%	11%	8%	0%	12%	0%	23%	11%	0%	0%	0%
6	14%	15%	0%	13%	17%	0%	0%	9%	0%	21%	11%	11%	16%	0%	21%	11%	9%	14%	5%	9%	0%
7	4%	5%	0%	0%	4%	0%	0%	9%	0%	0%	0%	10%	0%	0%	0%	10%	0%	4%	5%	9%	0%
8	14%	17%	0%	6%	17%	0%	0%	9%	0%	6%	22%	4%	31%	0%	16%	11%	14%	14%	5%	9%	0%
9	3%	4%	0%	0%	4%	0%	0%	0%	0%	7%	0%	0%	8%	0%	0%	4%	5%	3%	0%	0%	0%
10	16%	20%	0%	6%	15%	0%	0%	18%	18%	0%	20%	21%	16%	0%	13%	17%	18%	16%	18%	18%	18%
12	11%	10%	67%	0%	10%	0%	0%	9%	18%	14%	12%	15%	0%	0%	7%	20%	5%	11%	13%	9%	18%
13	1%	2%	0%	0%	2%	0%	0%	0%	0%	0%	0%	0%	8%	0%	0%	4%	0%	1%	0%	0%	0%
15	7%	6%	0%	12%	0%	0%	0%	18%	38%	14%	14%	3%	0%	0%	15%	3%	4%	7%	28%	18%	38%
Mean	7.67	8.09	8.67	6.02	7.16	.	.	8.00	10.20	7.48	8.75	7.07	7.66	.	7.93	8.14	6.78	7.67	9.10	8.00	10.20
N	74	56	3	15	53	0	0	11	10	13	19	29	13	0	24	28	22	74	21	11	10

ES2A. Were there more CPP Events than you expected, about as many as you expected, or fewer than you expected?	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
More than expected	21%	16%	33%	37%	19%	0%	0%	18%	38%	43%	15%	22%	8%	0%	32%	25%	5%	21%	28%	18%	38%
About what was expected	38%	40%	67%	25%	40%	0%	0%	36%	27%	31%	43%	41%	31%	0%	32%	30%	54%	38%	32%	36%	27%
Fewer than expected	37%	39%	0%	38%	35%	0%	0%	45%	36%	27%	31%	38%	53%	0%	31%	41%	37%	37%	41%	45%	36%
DON'T KNOW	4%	6%	0%	0%	6%	0%	0%	0%	0%	0%	11%	0%	8%	0%	4%	4%	5%	4%	0%	0%	0%
N	74	56	3	15	53	0	0	11	10	13	19	29	13	0	24	28	22	74	21	11	10

ES2B. For how many of the [ES1] CPP events was your organization able to reduce your energy usage?	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
0	11%	13%	0%	7%	9%	0%	0%	13%	29%	9%	13%	6%	22%	0%	10%	13%	10%	11%	20%	13%	29%
1	6%	6%	0%	7%	4%	0%	0%	0%	29%	16%	0%	7%	0%	0%	5%	7%	4%	6%	13%	0%	29%
2	9%	6%	33%	14%	8%	0%	0%	25%	0%	19%	12%	7%	0%	0%	5%	12%	9%	9%	13%	25%	0%
3	10%	6%	0%	29%	11%	0%	0%	13%	0%	8%	13%	15%	0%	0%	10%	4%	19%	10%	7%	13%	0%
4	9%	8%	0%	14%	9%	0%	0%	0%	14%	7%	0%	15%	8%	0%	0%	14%	10%	9%	7%	0%	14%
5	6%	4%	0%	14%	7%	0%	0%	0%	0%	9%	0%	11%	0%	0%	15%	0%	5%	6%	0%	0%	0%
6	13%	16%	0%	7%	15%	0%	0%	13%	0%	9%	13%	14%	16%	0%	25%	11%	5%	13%	7%	13%	0%
7	1%	2%	0%	0%	2%	0%	0%	0%	0%	0%	0%	4%	0%	0%	0%	4%	0%	1%	0%	0%	0%
8	15%	18%	0%	7%	17%	0%	0%	13%	0%	16%	13%	7%	31%	0%	20%	7%	19%	15%	7%	13%	0%
9	3%	4%	0%	0%	2%	0%	0%	0%	14%	0%	5%	0%	8%	0%	0%	7%	0%	3%	7%	0%	14%
10	7%	10%	0%	0%	6%	0%	0%	25%	0%	0%	18%	4%	8%	0%	5%	7%	9%	7%	13%	25%	0%
12	7%	4%	67%	0%	7%	0%	0%	0%	14%	0%	14%	9%	0%	0%	4%	10%	5%	7%	7%	0%	14%
13	1%	2%	0%	0%	2%	0%	0%	0%	0%	0%	0%	0%	8%	0%	0%	4%	0%	1%	0%	0%	0%
15	1%	2%	0%	0%	2%	0%	0%	0%	0%	9%	0%	0%	0%	0%	0%	0%	5%	1%	0%	0%	0%
Mean	5.45	5.76	8.67	3.50	5.67	.	.	5.13	3.86	4.59	6.31	4.96	6.22	.	5.35	5.49	5.50	5.45	4.54	5.13	3.86
N	68	51	3	14	53	0	0	8	7	12	16	27	13	0	20	27	21	68	15	8	7

DR4A. Why didn't you take demand reduction actions for some of the CPP events?	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
Operation was already shut down	0%	0%	.	0%	0%	.	.	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Don't need to take action to save money	0%	0%	.	0%	0%	.	.	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Could not respond that fast	9%	12%	.	0%	8%	.	.	0%	26%	0%	0%	12%	30%	0%	0%	34%	0%	9%	11%	0%	26%
Not available to bid	5%	6%	.	0%	8%	.	.	0%	0%	0%	0%	12%	0%	0%	0%	18%	0%	5%	0%	0%	0%
Never planning to bid for any event	4%	0%	.	20%	6%	.	.	0%	0%	18%	0%	0%	0%	0%	9%	0%	0%	4%	0%	0%	0%
Could not reduce load	59%	54%	.	80%	69%	.	.	60%	22%	78%	51%	67%	35%	0%	63%	35%	74%	59%	44%	60%	22%
System issue/No Password	0%	0%	.	0%	0%	.	.	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Do not remember why	5%	6%	.	0%	8%	.	.	0%	0%	0%	0%	0%	35%	0%	13%	0%	0%	5%	0%	0%	0%
Was not a mandtory reduction	0%	0%	.	0%	0%	.	.	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Does not make sense financially	4%	5%	.	0%	0%	.	.	0%	26%	0%	0%	11%	0%	0%	0%	0%	13%	4%	11%	0%	26%
Never been notified	8%	6%	.	20%	6%	.	.	20%	0%	0%	0%	11%	0%	100%	12%	13%	0%	8%	12%	20%	0%
Werent prepared	0%	1%	0%	0%	0%	0%	0%	0%	9%	2%	0%	0%	0%	0%	0%	0%	2%	2%	1%	0%	1%
Not participant anymore	1%	1%	0%	0%	0%	0%	0%	9%	0%	0%	2%	0%	0%	0%	1%	0%	0%	2%	1%	2%	0%
RECORD VERBATIM	5%	6%	.	0%	8%	.	.	0%	0%	0%	26%	0%	0%	0%	0%	18%	0%	5%	0%	0%	0%
REFUSED	0%	0%	.	0%	0%	.	.	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
DON'T KNOW	0%	0%	.	0%	0%	.	.	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
N	22	17	0	5	13	0	0	5	4	5	4	9	3	1	9	6	7	22	9	5	4

DR5_CPP. What type of demand reduction actions have you taken in response to 2005 CPP events?	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
Used backup generators	9%	7%	0%	18%	11%	.	.	7%	0%	18%	3%	11%	7%	.	10%	9%	8%	9%	4%	7%	0%
Allowed temperature to rise in the occup	41%	50%	31%	18%	37%	.	.	63%	38%	36%	42%	45%	36%	.	51%	41%	27%	41%	52%	63%	38%
Reduced overhead lighting	44%	50%	54%	22%	42%	.	.	49%	55%	27%	42%	42%	66%	.	60%	37%	34%	44%	51%	49%	55%
Reduced or shut off some/all production	19%	9%	91%	21%	24%	.	.	0%	9%	14%	24%	20%	10%	.	12%	24%	18%	19%	4%	0%	9%
Shut down completely	8%	6%	0%	17%	11%	.	.	0%	0%	7%	3%	11%	7%	.	5%	8%	10%	8%	0%	0%	0%
Turned off non-critical equipment	35%	37%	31%	31%	31%	.	.	49%	45%	26%	43%	32%	37%	.	41%	35%	28%	35%	47%	49%	45%
Shut down partially	29%	23%	91%	22%	31%	.	.	22%	27%	31%	25%	33%	23%	.	23%	41%	14%	29%	24%	22%	27%
Rescheduled EMS	5%	6%	0%	4%	7%	.	.	0%	0%	0%	3%	10%	0%	.	6%	0%	12%	5%	0%	0%	0%
Shifting energy use	2%	0%	23%	0%	3%	.	.	0%	0%	0%	0%	0%	10%	.	0%	4%	0%	2%	0%	0%	0%
Developed an energy monitoring program	0%	0%	0%	0%	0%	.	.	0%	0%	0%	0%	0%	0%	.	0%	0%	0%	0%	0%	0%	0%
Switch to steam absorbing cooling	0%	0%	0%	0%	0%	.	.	0%	0%	0%	0%	0%	0%	.	0%	0%	0%	0%	0%	0%	0%
RECORD VERBATIM	4%	5%	0%	0%	2%	.	.	7%	9%	9%	0%	6%	0%	.	3%	3%	5%	4%	8%	7%	9%
REFUSED	0%	0%	0%	0%	0%	.	.	0%	0%	0%	0%	0%	0%	.	0%	0%	0%	0%	0%	0%	0%
DON'T KNOW	0%	0%	0%	0%	0%	.	.	0%	0%	0%	0%	0%	0%	.	0%	0%	0%	0%	0%	0%	0%
N	84	56	5	23	59	0	0	14	11	11	24	35	14	0	31	33	20	84	25	14	11

DR23A (formerly CPP4A). What is the likelihood that you will take demand reduction actions for future CPP events?	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
Very likely	77%	79%	77%	71%	77%	0%	0%	82%	73%	59%	77%	80%	84%	100%	73%	80%	78%	77%	78%	82%	73%
Somewhat likely	15%	14%	0%	22%	16%	0%	0%	6%	20%	25%	15%	13%	10%	0%	17%	16%	8%	15%	12%	6%	20%
Neither Likely nor unlikely	1%	1%	0%	0%	0%	0%	0%	6%	0%	0%	0%	3%	0%	0%	3%	0%	0%	1%	3%	6%	0%
Somewhat unlikely	2%	2%	0%	4%	3%	0%	0%	0%	0%	0%	4%	2%	0%	0%	2%	0%	5%	2%	0%	0%	0%
Not at all likely	5%	4%	23%	4%	5%	0%	0%	6%	7%	16%	4%	3%	6%	0%	5%	4%	9%	5%	7%	6%	7%
N	99	67	5	27	68	0	0	17	14	15	27	39	17	1	38	37	24	99	31	17	14

ES3. Thinking back over the summer (May-Present), how many events would you say were called for the DBP program?	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
0	10%	5%	12%	22%	0%	6%	12%	0%	0%	8%	18%	9%	0%	0%	6%	12%	8%	0%	10%	5%	11%
1	5%	3%	6%	0%	0%	0%	6%	18%	9%	4%	5%	3%	13%	0%	10%	3%	6%	14%	5%	3%	6%
2	11%	1%	17%	0%	0%	2%	14%	0%	9%	16%	14%	5%	0%	0%	4%	13%	11%	4%	11%	2%	14%
3	5%	4%	6%	0%	0%	0%	6%	18%	0%	6%	5%	7%	0%	0%	2%	7%	6%	9%	5%	3%	6%
4	8%	5%	9%	33%	0%	6%	8%	9%	20%	11%	5%	10%	0%	0%	12%	8%	2%	15%	8%	7%	9%
5	10%	8%	11%	22%	0%	4%	12%	0%	18%	11%	6%	12%	14%	0%	10%	8%	16%	9%	10%	3%	13%
6	9%	5%	10%	22%	0%	8%	9%	9%	9%	7%	7%	12%	9%	0%	6%	9%	11%	9%	9%	8%	9%
7	3%	5%	2%	0%	0%	2%	4%	0%	0%	4%	2%	0%	9%	0%	8%	2%	0%	0%	3%	2%	3%

8	3%	3%	3%	0%	0%	8%	1%	0%	0%	1%	5%	3%	0%	0%	2%	2%	7%	0%	3%	7%	1%
9	1%	3%	1%	0%	0%	2%	1%	0%	0%	2%	2%	0%	5%	0%	2%	1%	3%	0%	1%	2%	1%
10	9%	10%	9%	0%	0%	18%	6%	9%	9%	9%	3%	9%	27%	0%	16%	9%	2%	9%	9%	17%	7%
12	5%	9%	3%	0%	0%	8%	5%	0%	0%	1%	4%	10%	9%	0%	2%	4%	13%	0%	5%	7%	5%
14	0%	1%	0%	0%	0%	2%	0%	0%	0%	1%	0%	0%	0%	0%	0%	1%	0%	0%	0%	2%	0%
15	6%	10%	4%	0%	0%	10%	4%	18%	0%	5%	9%	5%	4%	0%	6%	6%	5%	9%	6%	11%	4%
16	0%	1%	0%	0%	0%	2%	0%	0%	0%	1%	0%	0%	0%	0%	2%	0%	0%	0%	0%	2%	0%
18	1%	1%	1%	0%	0%	2%	1%	0%	0%	1%	2%	0%	0%	0%	0%	2%	0%	0%	1%	2%	1%
20	5%	7%	3%	0%	0%	8%	4%	9%	0%	1%	3%	10%	4%	0%	5%	5%	3%	5%	5%	8%	3%
21	3%	9%	0%	0%	0%	4%	3%	9%	0%	6%	2%	3%	0%	0%	0%	4%	5%	5%	3%	5%	3%
23	5%	8%	3%	0%	0%	6%	4%	0%	27%	4%	8%	3%	4%	0%	7%	5%	2%	13%	5%	5%	5%
Mean	7.82	11.43	5.90	3.78	.	11.15	6.61	9.00	9.51	7.24	7.44	8.49	8.75	.	8.23	7.77	7.44	9.26	7.82	10.79	6.78
N	158	79	75	4	0	49	88	11	10	53	45	45	15	0	41	89	28	21	158	60	98

ES4. Were there more DBP Events than you expected, about as many as you expected, or fewer than you expected?	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
More than expected	13%	19%	9%	22%	0%	12%	13%	18%	9%	10%	14%	13%	19%	0%	20%	11%	11%	14%	13%	13%	13%
About what was expected	49%	48%	48%	78%	0%	53%	47%	55%	47%	51%	46%	50%	46%	0%	43%	52%	47%	51%	49%	53%	47%
Fewer than expected	25%	25%	27%	0%	0%	31%	23%	27%	27%	23%	26%	29%	21%	0%	24%	22%	40%	27%	25%	30%	24%
DON'T KNOW	13%	8%	17%	0%	0%	4%	16%	0%	18%	17%	13%	9%	14%	0%	14%	16%	2%	9%	13%	3%	16%
N	158	79	75	4	0	49	88	11	10	53	45	45	15	0	41	89	28	21	158	60	98

ES5. For how many of those [ES3] DBP events did your organization submit a bid?	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
0	59%	47%	64%	100%	0%	0%	81%	0%	76%	52%	61%	60%	73%	0%	57%	62%	52%	32%	59%	0%	81%
1	11%	11%	12%	0%	0%	14%	10%	18%	12%	13%	9%	11%	14%	0%	9%	13%	12%	16%	11%	15%	10%
2	5%	7%	4%	0%	0%	12%	3%	9%	12%	6%	4%	7%	0%	0%	8%	4%	6%	10%	5%	11%	3%
3	4%	6%	3%	0%	0%	12%	1%	9%	0%	4%	4%	4%	0%	0%	2%	4%	5%	5%	4%	11%	1%
4	5%	5%	5%	0%	0%	14%	2%	18%	0%	8%	4%	5%	0%	0%	4%	4%	9%	10%	5%	15%	2%
5	3%	3%	3%	0%	0%	9%	0%	9%	0%	3%	6%	0%	0%	0%	0%	4%	0%	5%	3%	9%	0%
6	1%	0%	2%	0%	0%	5%	0%	0%	0%	2%	0%	0%	4%	0%	2%	1%	0%	0%	1%	4%	0%
7	2%	3%	1%	0%	0%	7%	0%	0%	0%	1%	4%	0%	0%	0%	0%	3%	0%	0%	2%	6%	0%
8	2%	1%	3%	0%	0%	7%	0%	9%	0%	2%	0%	3%	4%	0%	2%	1%	6%	5%	2%	7%	0%
10	2%	4%	0%	0%	0%	7%	0%	0%	0%	0%	0%	3%	4%	0%	2%	1%	3%	0%	2%	6%	0%
11	1%	1%	0%	0%	0%	2%	0%	0%	0%	0%	0%	2%	0%	0%	0%	1%	0%	0%	1%	2%	0%
12	1%	4%	0%	0%	0%	5%	0%	9%	0%	3%	0%	2%	0%	0%	2%	0%	5%	5%	1%	5%	0%
15	1%	1%	0%	0%	0%	2%	0%	0%	0%	1%	0%	0%	0%	0%	0%	1%	0%	0%	1%	2%	0%
16	1%	1%	0%	0%	0%	2%	0%	0%	0%	1%	0%	0%	0%	0%	2%	0%	0%	0%	1%	2%	0%
18	1%	3%	0%	0%	0%	2%	0%	9%	0%	3%	0%	0%	0%	0%	2%	0%	2%	5%	1%	4%	0%
20	0%	1%	0%	0%	0%	0%	0%	9%	0%	0%	2%	0%	0%	0%	2%	0%	0%	5%	0%	2%	0%
23	2%	0%	4%	0%	0%	0%	3%	0%	0%	0%	5%	4%	0%	0%	5%	2%	0%	0%	2%	0%	3%
Mean	2.34	3.32	1.86	0.00	0.00	5.70	1.02	7.09	0.36	2.49	2.58	2.45	1.19	0.00	3.42	1.82	2.54	4.24	2.34	5.96	0.99
N	136	68	65	3	0	43	75	11	7	47	34	41	14	0	35	76	25	18	136	54	82

ES5B(DBP3a). Why didn't you place a bid for some of the DBP events?	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
Operation was already shut down	4%	3%	4%	0%	.	3%	4%	0%	0%	0%	14%	2%	0%	.	3%	3%	7%	0%	4%	2%	4%
Don't need to take action to save money	9%	3%	13%	0%	.	17%	7%	0%	12%	2%	10%	16%	9%	.	11%	9%	7%	7%	9%	15%	7%
Could not respond that fast	12%	24%	6%	0%	.	25%	8%	0%	36%	18%	8%	9%	14%	.	10%	16%	3%	21%	12%	22%	10%
Not available to Bid that hour	10%	19%	6%	0%	.	22%	5%	50%	12%	14%	7%	9%	10%	.	13%	12%	3%	28%	10%	26%	6%
Never planning to Bid	2%	0%	3%	0%	.	3%	2%	0%	0%	5%	0%	0%	0%	.	0%	3%	0%	0%	2%	2%	2%
Could not reduce load on that particular	36%	35%	33%	100%	.	22%	39%	50%	27%	32%	19%	45%	55%	.	34%	32%	51%	37%	36%	26%	39%
System issue/ No password	7%	8%	6%	0%	.	17%	4%	0%	0%	3%	6%	6%	21%	.	18%	2%	7%	0%	7%	15%	4%
Doesn't make sense financially for us	3%	4%	2%	0%	.	0%	4%	0%	0%	4%	6%	0%	0%	.	0%	4%	0%	0%	3%	0%	3%
Couldnt reduce	15%	13%	17%	0%	-	5%	19%	0%	0%	15%	14%	6%	44%	.	19%	14%	14%	8%	15%	5%	18%
Not comfortable using the program/confusion	0%	0%	0%	0%	.	0%	0%	0%	0%	0%	0%	0%	0%	.	0%	0%	0%	0%	0%	0%	0%
Didnt get notice in time	9%	11%	8%	0%	.	14%	7%	33%	0%	13%	17%	2%	0%	.	13%	8%	6%	14%	9%	16%	7%
Incentive not enough	5%	3%	6%	0%	.	0%	6%	0%	12%	6%	2%	8%	0%	.	2%	8%	0%	7%	5%	0%	7%
Too busy	3%	5%	2%	0%	.	3%	3%	0%	12%	6%	0%	2%	5%	.	3%	2%	7%	7%	3%	2%	3%
Unavailable	2%	0%	3%	0%	.	3%	2%	0%	0%	2%	0%	0%	11%	.	8%	0%	0%	0%	2%	2%	2%
No plan set up	4%	5%	4%	0%	-	0%	5%	0%	0%	2%	11%	4%	0%	.	3%	4%	7%	8%	4%	0%	5%
Equipment failure	2%	2%	2%	0%	.	0%	3%	0%	0%	0%	8%	0%	0%	.	0%	3%	0%	0%	2%	0%	3%
RECORD VERBATIM	0%	1%	0%	0%	-	0%	0%	0%	12%	0%	0%	2%	0%	.	0%	0%	3%	6%	1%	0%	1%
REFUSED	0%	0%	0%	0%	.	0%	0%	0%	0%	0%	0%	0%	0%	.	0%	0%	0%	0%	0%	0%	0%
DON'T KNOW	1%	0%	2%	0%	.	0%	2%	0%	0%	0%	0%	4%	0%	.	0%	2%	0%	0%	1%	0%	2%
N	121	61	57	3	0	36	72	6	7	42	28	38	13	0	30	70	21	13	121	42	79

Bid4. Would extending the bidding window to 2 hours increase your bidding activities?	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
Yes	47%	49%	47%	29%	0%	75%	40%	50%	24%	46%	45%	50%	47%	0%	42%	47%	54%	35%	47%	72%	39%
No	49%	48%	49%	71%	0%	22%	56%	50%	64%	53%	53%	42%	53%	0%	50%	50%	46%	58%	49%	26%	57%
DON'T KNOW	4%	3%	4%	0%	0%	3%	4%	0%	12%	2%	2%	8%	0%	0%	8%	3%	0%	7%	4%	2%	4%
N	121	61	57	3	0	36	72	6	7	42	28	38	13	0	30	70	21	13	121	42	79

Bid5. If the bidding window was extended, would you prefer to be notified one hour earlier or having the bidding deadline extended one hour later?	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
Earlier Notification	46%	40%	48%	100%	0%	33%	51%	67%	50%	51%	59%	29%	55%	0%	50%	42%	54%	60%	46%	36%	51%
Later Bidding Deadline	36%	33%	39%	0%	0%	37%	38%	0%	50%	26%	29%	57%	23%	0%	37%	42%	20%	20%	36%	34%	38%
Either one - just give us the two hours	18%	27%	13%	0%	0%	30%	11%	33%	0%	23%	12%	14%	22%	0%	13%	17%	26%	20%	18%	30%	11%
N	61	30	30	1	0	27	29	3	2	21	13	20	7	0	14	36	11	5	61	30	31

ES6. For how many of those [ES3] DBP events did your organization reduce their energy usage?	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
0	49%	41%	54%	43%	0%	7%	65%	0%	64%	55%	41%	39%	68%	0%	52%	52%	36%	27%	49%	6%	65%
1	6%	5%	6%	0%	0%	12%	3%	18%	0%	3%	2%	15%	0%	0%	9%	5%	5%	10%	6%	13%	3%
2	9%	3%	13%	0%	0%	7%	11%	0%	0%	6%	12%	9%	10%	0%	2%	11%	12%	0%	9%	6%	10%
3	6%	8%	5%	0%	0%	12%	4%	9%	0%	6%	9%	4%	4%	0%	7%	4%	12%	5%	6%	11%	4%
4	8%	8%	9%	0%	0%	14%	5%	18%	24%	9%	16%	3%	4%	0%	6%	9%	9%	21%	8%	15%	6%
5	4%	3%	4%	29%	0%	7%	4%	0%	0%	7%	4%	2%	0%	0%	7%	3%	4%	0%	4%	6%	3%
6	3%	1%	4%	29%	0%	7%	3%	0%	0%	3%	2%	6%	0%	0%	0%	4%	6%	0%	3%	6%	3%
7	1%	3%	0%	0%	0%	5%	0%	0%	0%	1%	2%	0%	0%	0%	0%	2%	0%	0%	1%	4%	0%
8	2%	3%	3%	0%	0%	7%	0%	18%	0%	2%	4%	3%	0%	0%	2%	2%	6%	10%	2%	9%	0%
9	1%	1%	0%	0%	0%	2%	0%	0%	0%	0%	0%	0%	4%	0%	2%	0%	0%	0%	1%	2%	0%
10	2%	3%	1%	0%	0%	7%	0%	0%	0%	0%	0%	5%	0%	0%	0%	2%	3%	0%	2%	6%	0%
12	2%	6%	0%	0%	0%	2%	1%	18%	0%	3%	0%	4%	0%	0%	2%	2%	2%	10%	2%	5%	1%
15	1%	1%	0%	0%	0%	2%	0%	0%	0%	1%	0%	0%	0%	0%	0%	1%	0%	0%	1%	2%	0%
16	1%	1%	0%	0%	0%	2%	0%	0%	0%	1%	0%	0%	0%	0%	2%	0%	0%	0%	1%	2%	0%
20	2%	1%	2%	0%	0%	0%	2%	9%	0%	0%	2%	4%	0%	0%	2%	2%	0%	5%	2%	2%	2%
21	1%	1%	0%	0%	0%	2%	0%	0%	0%	0%	0%	2%	0%	0%	0%	0%	3%	0%	1%	2%	0%
23	4%	10%	0%	0%	0%	5%	3%	9%	12%	1%	5%	3%	9%	0%	7%	3%	3%	10%	4%	5%	3%
Mean	3.32	5.72	1.91	3.14	.	6.26	1.95	8.73	3.76	2.58	3.50	4.17	2.92	.	3.80	2.97	3.73	6.62	3.32	6.72	2.04
N	136	68	65	3	0	43	75	11	7	47	34	41	14	0	35	76	25	18	136	54	82

DR4B. Why didn't you take demand response actions for some of the DBP events?	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
Operation was already shut down	6%	2%	9%	0%	12%	0%	8%	0%	0%	4%	11%	6%	0%	.	12%	2%	6%	4%	5%	0%	8%
Don't need to take action to save money	1%	2%	0%	0%	0%	0%	1%	0%	0%	0%	0%	0%	7%	.	0%	1%	0%	0%	1%	0%	1%
Could not respond that fast	21%	31%	11%	32%	20%	37%	12%	42%	21%	27%	13%	20%	20%	.	29%	20%	11%	26%	21%	38%	13%
Not available to bid	15%	22%	10%	8%	8%	28%	9%	29%	11%	14%	17%	9%	30%	.	21%	9%	20%	15%	15%	28%	9%
Never planning to bid for any event	1%	0%	0%	14%	0%	5%	0%	0%	0%	0%	0%	3%	0%	.	4%	0%	0%	0%	1%	4%	0%
Could not reduce load	50%	42%	54%	68%	60%	23%	58%	43%	68%	52%	38%	52%	61%	.	27%	61%	53%	59%	49%	27%	59%
System issue/No Password	7%	9%	7%	0%	0%	15%	5%	14%	0%	8%	19%	2%	0%	.	14%	6%	3%	4%	8%	15%	5%
Do not remember why	7%	4%	11%	0%	0%	3%	11%	0%	0%	0%	7%	17%	0%	.	7%	8%	6%	0%	8%	2%	10%
Was not a mandtory reduction	1%	0%	2%	0%	0%	0%	2%	0%	0%	0%	0%	4%	0%	.	0%	0%	6%	0%	1%	0%	2%
Does not make sense financially	3%	4%	2%	0%	10%	0%	2%	0%	11%	4%	0%	5%	0%	.	0%	4%	4%	8%	2%	0%	3%
Staffing issue	1%	0%	2%	0%	0%	0%	2%	0%	0%	0%	0%	4%	0%	.	0%	0%	6%	0%	1%	0%	2%
Waiting to see results from before	3%	2%	5%	0%	0%	0%	4%	0%	11%	0%	11%	2%	0%	.	0%	6%	0%	4%	3%	0%	5%
Had to make sure it was actually suitable for us	1%	0%	3%	0%	0%	6%	0%	0%	0%	0%	0%	4%	0%	.	0%	0%	7%	0%	1%	5%	0%
Because the system doesnt work	1%	2%	0%	0%	0%	0%	1%	0%	0%	2%	0%	0%	0%	.	3%	0%	0%	0%	1%	0%	1%
RECORD VERBATIM	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	.	0%	0%	0%	0%	0%	0%	0%
REFUSED	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	.	0%	0%	0%	0%	0%	0%	0%

DON'T KNOW	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	.	0%	0%	0%	0%	0%	0%	0%
N	115	55	48	12	10	32	56	7	10	40	26	37	12	0	34	57	24	27	105	39	66

DR5_DBP (formerly EV10). What type of demand reduction actions have you taken in response to 2005 DBP events?	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
Used backup generators	10%	12%	9%	9%	.	15%	5%	19%	0%	13%	5%	12%	11%	.	17%	3%	15%	12%	10%	16%	5%
Allowed temperature to rise in the occup	32%	38%	24%	49%	.	28%	28%	49%	46%	18%	35%	41%	27%	.	34%	27%	38%	48%	32%	32%	31%
Reduced overhead lighting	34%	34%	32%	50%	.	21%	35%	55%	67%	16%	53%	33%	47%	.	41%	32%	30%	59%	34%	29%	39%
Reduced or shut off some/all production	16%	17%	16%	17%	.	32%	8%	0%	12%	31%	11%	8%	10%	.	11%	24%	9%	4%	16%	24%	9%
Shut down completely	5%	3%	6%	0%	.	9%	3%	0%	0%	0%	11%	4%	0%	.	0%	9%	3%	0%	5%	7%	2%
Turned off non-critical equipment	41%	48%	33%	50%	.	31%	46%	42%	56%	43%	50%	31%	39%	.	26%	51%	39%	47%	41%	34%	47%
Shut down partially	23%	23%	22%	26%	.	25%	24%	19%	10%	21%	16%	32%	11%	.	24%	20%	26%	16%	23%	23%	22%
Rescheduled EMS	6%	3%	10%	0%	.	7%	8%	0%	0%	9%	11%	2%	0%	.	6%	7%	5%	0%	6%	6%	7%
Shifting energy use	3%	2%	4%	0%	.	5%	2%	0%	0%	0%	5%	4%	0%	.	0%	6%	0%	0%	3%	4%	1%
Developed an energy monitoring program	1%	0%	2%	0%	.	0%	3%	0%	0%	4%	0%	0%	0%	.	0%	0%	5%	0%	1%	0%	2%
Switch to steam absorbing cooling	1%	2%	0%	0%	.	0%	0%	6%	0%	2%	0%	0%	0%	.	0%	0%	3%	4%	1%	1%	0%
RECORD VERBATIM	5%	3%	6%	0%	.	4%	5%	0%	12%	4%	0%	4%	29%	.	8%	2%	5%	4%	5%	3%	6%
REFUSED	1%	3%	0%	0%	.	0%	3%	0%	0%	2%	0%	2%	0%	.	0%	3%	0%	0%	1%	0%	3%
DON'T KNOW	0%	0%	0%	0%	.	0%	0%	0%	0%	0%	0%	0%	0%	.	0%	0%	0%	0%	0%	0%	0%
N	122	58	54	10	0	53	44	16	9	38	35	41	8	0	39	56	27	25	122	69	53

ES7a. Were there any DBP events during this past summer for which your organization placed a bid and then did not take any demand reduction actions?	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
Yes	11%	14%	9%	0%	0%	15%	0%	18%	0%	13%	0%	5%	57%	0%	18%	11%	5%	15%	11%	16%	0%
No	84%	83%	85%	0%	0%	83%	87%	82%	100%	79%	100%	90%	43%	0%	82%	86%	82%	85%	84%	82%	88%
DON'T KNOW	5%	3%	6%	0%	0%	2%	13%	0%	0%	8%	0%	5%	0%	0%	0%	3%	13%	0%	5%	2%	12%
N	62	35	27	0	0	40	9	11	2	25	14	19	4	0	15	33	14	13	62	51	11

ES7b. Why didn't your organization take any demand reduction actions after placing the bid?	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
Operation was already shut down	5%	2%	9%	0%	8%	0%	10%	0%	0%	0%	8%	8%	0%	0%	13%	0%	0%	4%	4%	0%	9%
Dont need to take action to save money	1%	2%	0%	0%	0%	0%	3%	0%	0%	0%	0%	0%	12%	0%	0%	2%	0%	0%	1%	0%	3%
Not available to bid	18%	21%	17%	7%	6%	22%	23%	13%	0%	14%	29%	14%	23%	0%	17%	16%	24%	6%	20%	20%	19%
Never planning to bid for any event	3%	0%	3%	19%	6%	7%	0%	0%	0%	5%	0%	5%	0%	0%	7%	2%	0%	3%	3%	6%	0%
Could not reduce load	45%	33%	53%	66%	60%	31%	50%	25%	85%	46%	34%	55%	31%	0%	29%	56%	49%	56%	42%	30%	56%
System issue/No Password	8%	6%	12%	0%	0%	8%	10%	13%	0%	8%	22%	0%	0%	0%	9%	7%	5%	4%	9%	9%	9%
Was not a mandtory reduction	2%	0%	5%	0%	0%	0%	5%	0%	0%	0%	0%	5%	0%	0%	0%	0%	9%	0%	2%	0%	4%
Does not make sense financially	3%	0%	9%	0%	0%	0%	10%	0%	0%	0%	0%	10%	0%	0%	0%	4%	9%	0%	4%	0%	9%
Could not respond that fast	22%	29%	10%	28%	13%	28%	16%	37%	15%	26%	18%	23%	12%	0%	28%	19%	16%	20%	23%	30%	16%
Never been notified	1%	0%	0%	7%	6%	0%	0%	0%	0%	0%	0%	0%	0%	100%	0%	2%	0%	3%	0%	0%	0%
Equipment failure	2%	4%	0%	0%	0%	3%	0%	13%	0%	3%	0%	0%	12%	0%	3%	0%	5%	4%	2%	5%	0%
Client complaints	1%	2%	0%	0%	0%	0%	0%	13%	0%	3%	0%	0%	0%	0%	3%	0%	0%	4%	1%	2%	0%
First try	1%	0%	3%	0%	0%	3%	0%	0%	0%	0%	0%	0%	11%	0%	0%	2%	0%	0%	1%	2%	0%
PGE cancelled event	1%	2%	0%	0%	0%	3%	0%	0%	0%	3%	0%	0%	0%	0%	0%	2%	0%	0%	1%	2%	0%
RECORD VERBATIM	4%	4%	5%	0%	8%	8%	0%	0%	0%	3%	5%	6%	0%	0%	3%	3%	10%	4%	3%	7%	0%
REFUSED	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
DON'T KNOW	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
N	90	48	28	14	15	36	24	8	7	31	20	29	9	1	33	39	18	30	75	44	31

ES7c1. Were there any DBP events during this past summer for which your organization took demand reduction actions despite not placing a bid?	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
Yes	53%	53%	52%	100%	0%	50%	63%	30%	0%	43%	55%	66%	19%	0%	60%	57%	39%	25%	53%	46%	61%
No	44%	47%	44%	0%	0%	50%	31%	70%	100%	57%	36%	34%	81%	0%	40%	38%	61%	75%	44%	54%	34%
DON'T KNOW	2%	0%	4%	0%	0%	0%	5%	0%	0%	0%	9%	0%	0%	0%	0%	4%	0%	0%	2%	0%	5%
N	73	35	36	2	0	38	23	10	2	25	19	25	4	0	17	40	16	12	73	48	25

ES7c2. Why didn't your organization place a bid for these events?	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
Missed Bidding Window	27%	46%	18%	0%	.	48%	12%	33%	.	34%	30%	18%	100%	.	53%	25%	0%	33%	27%	46%	12%
Could not meet bid minimum (50KW)	21%	17%	16%	100%	.	5%	30%	33%	.	0%	7%	42%	0%	.	0%	31%	15%	33%	21%	9%	30%
Not worth the time given economic incent	7%	0%	12%	0%	.	5%	8%	0%	.	26%	0%	0%	0%	.	19%	4%	0%	0%	7%	5%	8%
Confusion	17%	20%	16%	0%	100%	10%	16%	33%	.	16%	39%	4%	0%	.	0%	14%	47%	52%	15%	13%	16%
Unprepared/still learning system	22%	11%	31%	0%	.	11%	29%	33%	.	9%	47%	15%	0%	.	29%	22%	12%	33%	22%	13%	29%
Wasnt around on Sunday/ out of town	6%	11%	4%	0%	.	16%	0%	0%	.	16%	0%	5%	0%	.	0%	10%	0%	0%	6%	14%	0%
Problems with equipment	9%	0%	16%	0%	.	0%	16%	0%	.	0%	16%	10%	0%	.	0%	8%	26%	0%	9%	0%	16%
Already off line	2%	5%	0%	0%	.	5%	0%	0%	.	0%	0%	4%	0%	.	0%	3%	0%	0%	2%	5%	0%
System glitch	2%	5%	0%	0%	.	5%	0%	0%	.	0%	0%	0%	100%	.	8%	0%	0%	0%	2%	5%	0%
Reduced load, just didnt bid	2%	0%	4%	0%	.	5%	0%	0%	.	0%	0%	5%	0%	.	9%	0%	0%	0%	2%	5%	0%
RECORD VERBATIM	2%	5%	0%	0%	0%	5%	0%	0%	.	8%	0%	0%	0%	.	8%	0%	0%	0%	2%	5%	0%
REFUSED	0%	0%	0%	0%	.	0%	0%	0%	.	0%	0%	0%	0%	.	0%	0%	0%	0%	0%	0%	0%
DON'T KNOW	5%	0%	8%	0%	.	0%	8%	0%	.	0%	0%	10%	0%	.	0%	8%	0%	0%	5%	0%	8%
N	37	18	17	2	0	19	15	3	0	11	10	15	1	0	9	22	6	3	37	22	15

DR23B (formerly DBP4A). What is the likelihood that you will take demand reduction actions for future DBP events?	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
Very likely	34%	45%	26%	61%	0%	59%	22%	76%	43%	33%	41%	29%	34%	0%	34%	30%	45%	61%	34%	62%	23%
Somewhat likely	30%	29%	31%	13%	0%	28%	32%	12%	28%	26%	26%	35%	33%	0%	33%	28%	28%	19%	30%	25%	31%
Neither Likely nor unlikely	5%	3%	6%	0%	0%	6%	5%	0%	0%	6%	6%	2%	8%	0%	1%	5%	10%	0%	5%	5%	5%
Somewhat unlikely	14%	10%	17%	19%	0%	5%	19%	0%	6%	24%	7%	16%	3%	0%	11%	19%	6%	3%	14%	4%	18%
Not at all likely	16%	11%	20%	7%	0%	1%	21%	12%	22%	10%	18%	18%	21%	0%	20%	16%	12%	17%	16%	4%	21%
DON'T KNOW	1%	2%	0%	0%	0%	0%	1%	0%	0%	1%	1%	0%	0%	0%	0%	1%	0%	0%	1%	0%	1%
N	230	100	117	13	0	63	136	17	14	71	63	72	24	0	66	121	43	31	230	80	150

ES99. How likely is it that you would have taken peak load reduction actions this past summer if no financial incentives were offered?	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
Definitely would NOT have take peak load	30%	20%	39%	27%	17%	14%	41%	18%	9%	33%	36%	20%	34%	0%	29%	33%	24%	16%	33%	15%	39%
Probably would NOT have taken peak load	27%	23%	28%	32%	25%	37%	26%	18%	9%	26%	27%	26%	26%	0%	19%	28%	32%	22%	27%	34%	25%
Probably would have taken peak load redu	28%	34%	24%	22%	28%	39%	22%	55%	36%	20%	26%	41%	17%	0%	27%	28%	30%	33%	28%	41%	23%
Definitely would have taken peak load re	13%	21%	6%	20%	28%	10%	8%	9%	38%	14%	10%	12%	23%	0%	25%	10%	9%	27%	10%	10%	10%
DON'T KNOW	2%	2%	3%	0%	2%	0%	3%	0%	9%	7%	1%	0%	0%	0%	0%	2%	5%	3%	2%	0%	3%
N	211	115	78	18	53	49	88	11	10	60	56	68	27	0	57	108	46	74	158	60	98

ES7d. Thinking back to all of the program events this summer, how critical did your organization feel these events were in helping [UTILITY] manage their power supply and/or avoid rolling blackouts.	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
Very critical	34%	29%	40%	23%	27%	33%	37%	27%	53%	25%	36%	37%	45%	0%	33%	32%	41%	30%	36%	32%	38%
Somewhat critical or	52%	55%	48%	64%	60%	51%	49%	64%	47%	65%	50%	49%	36%	0%	54%	52%	50%	59%	50%	53%	49%
Not at all critical	7%	10%	5%	0%	6%	9%	7%	9%	0%	6%	5%	8%	9%	0%	3%	9%	6%	6%	7%	9%	6%
DON'T KNOW	7%	5%	8%	12%	7%	7%	7%	0%	0%	4%	9%	7%	10%	0%	10%	7%	4%	5%	7%	6%	7%
N	194	107	70	17	53	43	77	11	10	56	48	64	26	0	52	98	44	74	141	54	87

ES7e. Would your organizations' response have been different if you felt the need was more critical?	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
Yes	56%	48%	65%	58%	42%	50%	65%	50%	81%	57%	53%	62%	46%	0%	60%	54%	57%	47%	61%	50%	66%
No	43%	51%	35%	42%	58%	50%	35%	50%	0%	42%	47%	38%	54%	0%	40%	46%	40%	51%	38%	50%	33%
REFUSED	1%	1%	0%	0%	0%	0%	0%	0%	19%	2%	0%	0%	0%	0%	0%	0%	3%	2%	1%	0%	1%
N	117	70	36	11	35	26	44	8	4	40	28	37	12	0	31	60	26	47	82	34	48

ES7f. How would it have been different?	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
Would reduce more load	44%	39%	46%	58%	40%	39%	48%	75%	0%	52%	34%	46%	28%	.	53%	41%	41%	39%	45%	47%	44%
Would try harder to reduce load	25%	30%	18%	42%	47%	31%	16%	0%	53%	10%	30%	29%	58%	.	38%	16%	30%	40%	20%	24%	18%
Might reduce load	14%	15%	16%	0%	7%	8%	18%	0%	24%	7%	19%	22%	0%	.	0%	19%	18%	8%	16%	6%	19%
Run generators	6%	6%	5%	14%	13%	8%	5%	0%	0%	3%	18%	4%	0%	.	0%	2%	24%	9%	5%	6%	4%
Educate users	4%	3%	5%	0%	0%	0%	5%	25%	0%	10%	0%	0%	0%	.	4%	5%	0%	4%	5%	5%	4%

RECORD VERBATIM	9%	9%	10%	0%	7%	15%	9%	0%	0%	10%	18%	0%	14%	.	4%	12%	6%	5%	9%	12%	8%
REFUSED	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	.	0%	0%	0%	0%	0%	0%	0%
DON'T KNOW	4%	3%	5%	0%	0%	0%	5%	0%	24%	7%	0%	3%	0%	.	0%	7%	0%	4%	4%	0%	6%
N	61	34	21	6	15	13	26	4	3	20	14	21	6	0	17	30	14	22	46	17	29

DREVER_CPP. Are there any circumstances under which your organization would consider taking demand reduction actions for future CPP events?	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
No circumstances	28%	21%	0%	100%	50%	0%	0%	0%	25%	100%	50%	0%	0%	0%	68%	0%	35%	28%	14%	0%	25%
Yes - non specific	19%	21%	0%	0%	25%	0%	0%	33%	0%	0%	27%	25%	0%	0%	32%	22%	0%	19%	14%	33%	0%
Yes - if its critical	17%	19%	0%	0%	0%	0%	0%	67%	0%	0%	23%	25%	0%	0%	0%	39%	0%	17%	29%	67%	0%
Yes - if I can run the generator	9%	9%	0%	0%	0%	0%	0%	0%	25%	0%	0%	25%	0%	0%	0%	0%	30%	9%	14%	0%	25%
Yes - if its in the winter	9%	9%	0%	0%	0%	0%	0%	0%	25%	0%	0%	0%	46%	0%	0%	19%	0%	9%	14%	0%	25%
Yes - if we are slow	9%	9%	0%	0%	0%	0%	0%	0%	25%	0%	0%	25%	0%	0%	0%	19%	0%	9%	14%	0%	25%
DON'T KNOW	10%	11%	0%	0%	25%	0%	0%	0%	0%	0%	0%	0%	54%	0%	0%	0%	35%	10%	0%	0%	0%
N	11	10	0	1	4	0	0	3	4	1	4	4	2	0	3	5	3	11	7	3	4

SIGNUP_CPP. Given that your organization has not yet taken demand reduction actions for any CPP events and can't see circumstances under which they would, why did your organization signup for CPP?	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
less cost for electricity	35%	54%	.	0%	50%	.	.	.	0%	0%	54%	.	.	.	0%	.	100%	35%	0%	.	0%
benefit financially	35%	0%	.	100%	50%	.	.	.	0%	100%	0%	.	.	.	54%	.	0%	35%	0%	.	0%
RECORD VERBATIM	0%	0%	.	0%	0%	.	.	.	0%	0%	0%	.	.	.	0%	.	0%	0%	0%	.	0%
REFUSED	0%	0%	.	0%	0%	.	.	.	0%	0%	0%	.	.	.	0%	.	0%	0%	0%	.	0%
DON'T KNOW	30%	46%	.	0%	0%	.	.	.	100%	0%	46%	.	.	.	46%	.	0%	30%	100%	.	100%
N	3	2	0	1	2	0	0	0	1	1	2	0	0	0	2	0	1	3	1	0	1

DREVER_DBP. Are there any circumstances under which your organization would consider taking demand reduction actions for future DBP events?	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
No circumstances	35%	25%	40%	0%	0%	0%	37%	0%	25%	24%	44%	0%	61%	0%	40%	23%	56%	25%	35%	0%	36%
Yes - non specific	9%	24%	0%	0%	0%	49%	6%	0%	25%	16%	13%	0%	0%	0%	7%	7%	14%	25%	9%	49%	7%
Yes - if its critical	9%	9%	8%	0%	0%	51%	6%	0%	25%	0%	11%	33%	0%	0%	13%	10%	0%	25%	9%	51%	7%
Yes - if incentives are increased	15%	11%	17%	0%	0%	0%	16%	0%	0%	24%	13%	23%	0%	0%	16%	21%	0%	0%	15%	0%	15%
Yes - if its feasible	7%	11%	6%	0%	0%	0%	8%	0%	0%	12%	13%	0%	0%	0%	8%	10%	0%	0%	7%	0%	8%
Yes - if we get better notice	4%	0%	6%	0%	0%	0%	4%	0%	0%	0%	0%	0%	15%	0%	16%	0%	0%	0%	4%	0%	4%
Yes - if it doesnt affect our business	4%	0%	6%	0%	0%	0%	4%	0%	0%	12%	0%	0%	0%	0%	0%	0%	16%	0%	4%	0%	4%
Yes - if its in the winter	4%	0%	6%	0%	0%	0%	4%	0%	0%	0%	0%	0%	15%	0%	0%	7%	0%	0%	4%	0%	4%
Yes - if cogen is up	2%	5%	0%	0%	0%	0%	2%	0%	0%	0%	6%	0%	0%	0%	0%	0%	8%	0%	2%	0%	2%
Yes - if I can run the generator	1%	4%	0%	0%	0%	0%	0%	0%	25%	0%	0%	9%	0%	0%	0%	0%	6%	25%	1%	0%	1%
Maybe	4%	11%	0%	0%	0%	0%	4%	0%	0%	0%	0%	12%	8%	0%	0%	7%	0%	0%	4%	0%	4%
RECORD VERBATIM	4%	0%	6%	0%	0%	0%	4%	0%	0%	12%	0%	0%	0%	0%	0%	7%	0%	0%	4%	0%	4%
DON'T KNOW	4%	0%	6%	0%	0%	0%	4%	0%	0%	0%	0%	23%	0%	0%	0%	7%	0%	0%	4%	0%	4%
N	38	20	18	0	0	2	32	0	4	13	12	6	7	0	10	19	9	4	38	2	36

SIGNUP_DBP. Given that your organization has not yet taken demand reduction actions for any DBP events and can't see circumstances under which they would, why did your organization signup for DBP?	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
Thought we could part	38%	50%	33%	.	.	.	38%	.	.	34%	43%	.	33%	.	40%	0%	100%	.	38%	.	38%
By mistake	25%	0%	33%	.	.	.	25%	.	.	0%	28%	.	33%	.	40%	29%	0%	.	25%	.	25%
planned an expansion that didnt happen	12%	0%	17%	.	.	.	12%	.	.	0%	0%	.	33%	.	0%	29%	0%	.	12%	.	12%
rep said to sign up	17%	50%	7%	.	.	100%	13%	.	.	0%	29%	100%	0%	.	32%	14%	0%	.	17%	100%	13%
thought we would have more notice	12%	0%	17%	.	.	.	12%	.	.	66%	0%	.	0%	.	0%	29%	0%	.	12%	.	12%
incentives	12%	0%	17%	.	.	.	12%	.	.	0%	0%	.	33%	.	0%	0%	50%	.	12%	.	12%
real-time monitoring	6%	25%	0%	.	.	.	6%	.	.	0%	14%	.	0%	.	20%	0%	0%	.	6%	.	6%
RECORD VERBATIM	0%	0%	0%	.	.	0%	0%	.	.	0%	0%	0%	0%	.	0%	0%	0%	.	0%	0%	0%
REFUSED	0%	0%	0%	.	.	.	0%	.	.	0%	0%	.	0%	.	0%	0%	0%	.	0%	.	0%
DON'T KNOW	0%	0%	0%	.	.	.	0%	.	.	0%	0%	.	0%	.	0%	0%	0%	.	0%	.	0%
N	10	4	6	0	0	0	10	0	0	2	5	0	3	0	4	4	2	0	10	0	10

DR25. Have you adjusted your summer load shape since signing up for the CPP program to take advantage of reduced on-peak and mid-peak prices or demand charges during non-CPP event hours?	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
Yes	45%	42%	31%	59%	46%	0%	0%	40%	44%	45%	29%	55%	45%	100%	54%	41%	36%	45%	42%	40%	44%
No	53%	55%	69%	41%	52%	0%	0%	54%	56%	55%	71%	42%	49%	0%	43%	56%	64%	53%	55%	54%	56%
DON'T KNOW	2%	3%	0%	0%	2%	0%	0%	6%	0%	0%	0%	3%	6%	0%	3%	2%	0%	2%	3%	6%	0%
N	99	67	5	27	68	0	0	17	14	15	27	39	17	1	38	37	24	99	31	17	14

ADJUST. How did you adjust your load shape on non critical peak days?	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
Shifted loads off peak	46%	40%	100%	50%	52%	.	.	25%	33%	58%	38%	54%	26%	0%	31%	64%	42%	46%	29%	25%	33%
Changed our hours of operation	22%	24%	0%	19%	12%	.	.	45%	50%	15%	13%	21%	38%	0%	39%	12%	0%	22%	47%	45%	50%
Scheduling	15%	18%	0%	12%	15%	.	.	15%	17%	15%	10%	9%	38%	0%	16%	6%	32%	15%	16%	15%	17%
Use minimum load possible	2%	4%	0%	0%	3%	.	.	0%	0%	0%	0%	5%	0%	0%	0%	0%	13%	2%	0%	0%	0%
Made adjustments to weekend shifts	5%	7%	0%	0%	3%	.	.	15%	0%	15%	14%	0%	0%	0%	11%	0%	0%	5%	8%	15%	0%
Reduced hours during peak periods	2%	4%	0%	0%	3%	.	.	0%	0%	0%	0%	5%	0%	0%	0%	7%	0%	2%	0%	0%	0%
RECORD VERBATIM	13%	14%	0%	12%	12%	.	.	15%	17%	12%	25%	5%	13%	100%	9%	18%	12%	13%	16%	15%	17%
REFUSED	0%	0%	0%	0%	0%	.	.	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
DON'T KNOW	2%	0%	0%	6%	2%	.	.	0%	0%	0%	0%	0%	9%	0%	4%	0%	0%	2%	0%	0%	0%
N	46	28	2	16	33	0	0	7	6	7	8	22	8	1	21	16	9	46	13	7	6

ADJUST2. Was this adjustment permanent or for the summer months only?	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
Permanent	28%	23%	0%	44%	32%	0%	0%	33%	0%	33%	41%	27%	17%	0%	41%	27%	12%	28%	14%	33%	0%
CPP Event Days Only	57%	60%	100%	44%	60%	0%	0%	33%	50%	36%	59%	67%	51%	0%	43%	65%	67%	57%	43%	33%	50%
Summer months only	12%	13%	0%	11%	8%	0%	0%	33%	25%	31%	0%	7%	17%	0%	16%	0%	22%	12%	29%	33%	25%
OTHER RECORD VERBATIM	3%	4%	0%	0%	0%	0%	0%	0%	25%	0%	0%	0%	15%	0%	0%	8%	0%	3%	14%	0%	25%
N	32	22	1	9	25	0	0	3	4	6	5	15	6	0	12	11	9	32	7	3	4

ES8. How well prepared was your organization to manage the demand reductions called for by [UTILTY]'s Demand Response programs this summer?	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
Very well prepared	35%	44%	29%	30%	54%	43%	26%	45%	36%	42%	29%	36%	29%	0%	35%	32%	42%	50%	31%	43%	26%
Somewhat prepared	45%	47%	43%	42%	41%	43%	46%	55%	44%	35%	43%	56%	39%	0%	39%	48%	43%	43%	45%	45%	46%
Not at all prepared	19%	8%	26%	28%	4%	12%	27%	0%	20%	20%	26%	8%	30%	0%	23%	20%	11%	5%	23%	10%	27%
DON'T KNOW	2%	1%	2%	0%	2%	2%	1%	0%	0%	3%	1%	0%	3%	0%	3%	0%	3%	1%	1%	2%	1%
N	211	115	78	18	53	49	88	11	10	60	56	68	27	0	57	108	46	74	158	60	98

ES8A. And why was that?	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
Cant reduce load/stop process	18%	22%	18%	7%	21%	30%	16%	33%	0%	13%	30%	13%	17%	.	19%	18%	19%	19%	18%	30%	15%
Inexperience/lack of practice/unprepared	15%	19%	11%	17%	13%	15%	15%	0%	28%	7%	4%	21%	34%	.	18%	13%	17%	13%	15%	12%	15%
Production demand/Too busy	8%	11%	6%	7%	8%	7%	7%	0%	28%	11%	4%	11%	0%	.	5%	10%	3%	10%	8%	6%	8%
Cant respond that quickly	3%	6%	1%	7%	4%	15%	1%	0%	0%	7%	6%	0%	0%	.	0%	5%	3%	3%	3%	12%	1%
Cant afford to shut down	5%	3%	6%	7%	4%	4%	6%	0%	0%	2%	4%	10%	0%	.	10%	4%	0%	3%	5%	3%	6%
Only one person knowledgable	3%	1%	4%	0%	0%	7%	2%	17%	0%	11%	0%	0%	0%	.	10%	1%	0%	2%	3%	9%	2%
Couldnt meet load reduction	1%	2%	0%	9%	4%	0%	1%	0%	0%	0%	2%	2%	0%	.	0%	0%	7%	3%	1%	0%	1%
Have a plan/Done it before	11%	11%	14%	0%	8%	7%	13%	0%	28%	7%	13%	13%	13%	.	5%	12%	20%	10%	12%	6%	13%
Not enough support from management	2%	2%	1%	9%	4%	4%	1%	0%	0%	2%	3%	0%	4%	.	5%	1%	0%	3%	2%	3%	1%
We do what we can	1%	3%	0%	0%	0%	0%	1%	17%	0%	0%	2%	2%	0%	.	2%	0%	4%	2%	1%	3%	1%
Staff changes	2%	1%	2%	7%	4%	0%	2%	17%	0%	0%	2%	6%	0%	.	0%	3%	3%	5%	2%	3%	2%
Time/Availability	5%	7%	5%	0%	4%	0%	7%	0%	0%	7%	7%	4%	0%	.	3%	5%	7%	3%	5%	0%	6%
Equipment problems	2%	3%	2%	0%	4%	0%	3%	0%	0%	0%	7%	2%	0%	.	0%	4%	0%	3%	2%	0%	3%
RECORD VERBATIM	24%	11%	32%	29%	21%	15%	27%	17%	31%	33%	21%	21%	22%	.	27%	24%	20%	22%	25%	15%	27%
REFUSED	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	.	0%	0%	0%	0%	0%	0%	0%
DON'T KNOW	2%	2%	2%	0%	4%	0%	2%	0%	0%	0%	2%	0%	9%	.	0%	1%	7%	3%	1%	0%	2%
N	127	63	52	12	24	27	64	6	6	34	36	41	16	0	33	70	24	36	103	33	70

DR9 (formerly EV13). Did your organization experience any impacts in terms of personnel comfort or productivity as a result of your demand reduction actions?	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
Yes	31%	36%	23%	42%	33%	37%	19%	48%	47%	35%	23%	29%	50%	0%	34%	35%	19%	37%	31%	39%	23%
No	68%	64%	75%	58%	67%	63%	78%	52%	53%	65%	74%	71%	50%	0%	66%	63%	81%	63%	68%	61%	75%
DON'T KNOW	1%	0%	2%	0%	0%	0%	2%	0%	0%	0%	3%	0%	0%	0%	0%	2%	0%	0%	1%	0%	2%
N	189	97	63	29	59	54	48	17	11	45	52	71	21	0	61	84	44	87	130	71	59

IMPACT. Please explain the impacts your organization experienced.	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
Staff complaints (lost hours, etc)	42%	40%	46%	39%	45%	32%	40%	49%	60%	35%	72%	24%	50%	.	40%	46%	28%	48%	40%	37%	45%
Warm/Uncomfortable work environment	48%	52%	36%	54%	64%	28%	48%	37%	80%	36%	60%	59%	29%	.	46%	47%	53%	60%	41%	30%	56%
Lost production	33%	28%	49%	23%	33%	40%	33%	13%	40%	46%	33%	24%	31%	.	26%	42%	20%	29%	33%	32%	35%
Financial Impact	16%	20%	9%	16%	17%	21%	14%	13%	0%	20%	22%	8%	18%	.	13%	19%	11%	14%	15%	18%	10%
Safety concerns with limited lighting	2%	0%	9%	0%	8%	0%	0%	0%	0%	9%	0%	0%	0%	.	0%	5%	0%	5%	0%	0%	0%
Company found higher temperature and lower lightin	2%	3%	0%	0%	0%	5%	0%	0%	0%	0%	8%	0%	0%	.	5%	0%	0%	0%	2%	4%	0%
Had to pay to have someone come out at night to turr	2%	3%	0%	0%	0%	5%	0%	0%	0%	6%	0%	0%	0%	.	0%	0%	11%	0%	2%	4%	0%
RECORD VERBATIM	9%	11%	10%	0%	5%	15%	0%	25%	0%	16%	7%	5%	10%	.	14%	8%	0%	9%	11%	18%	0%
REFUSED	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	.	0%	0%	0%	0%	0%	0%	0%
DON'T KNOW	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	.	0%	0%	0%	0%	0%	0%	0%
N	61	35	15	11	19	19	10	8	5	18	13	20	10	0	21	31	9	32	42	27	15

RAMP. For the events for which you took demand reduction actions, how long did it take your organization to fully ramp up to your normal electrical consumption level after the event was over?	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
No time at all	21%	26%	19%	13%	23%	24%	23%	9%	0%	25%	11%	25%	26%	0%	21%	20%	24%	19%	21%	21%	21%
Less than 10 minutes	7%	7%	9%	0%	4%	8%	8%	18%	0%	6%	8%	6%	13%	0%	6%	8%	6%	6%	9%	10%	7%
Between 10 and 20 minutes	9%	6%	13%	8%	0%	11%	16%	18%	0%	14%	9%	4%	14%	0%	11%	9%	6%	3%	13%	12%	14%
Between 20 and 30 minutes	9%	6%	9%	19%	13%	8%	5%	9%	0%	9%	6%	13%	0%	0%	6%	9%	11%	11%	6%	8%	5%
Between 30 minutes to an hour	15%	10%	21%	19%	15%	16%	16%	9%	17%	8%	24%	18%	0%	0%	11%	22%	5%	14%	15%	14%	16%
More than an hour	20%	16%	23%	28%	21%	13%	27%	0%	33%	21%	24%	16%	20%	0%	14%	21%	23%	19%	19%	10%	27%
No ramp up required (eg facility closes)	15%	24%	5%	13%	21%	16%	5%	18%	33%	14%	14%	16%	20%	0%	23%	8%	21%	22%	12%	16%	8%
Dont ramp up until the next day	3%	5%	2%	0%	2%	5%	0%	18%	0%	3%	2%	3%	7%	0%	5%	1%	5%	4%	4%	8%	0%
DON'T KNOW	1%	1%	0%	0%	0%	0%	0%	0%	17%	0%	2%	0%	0%	0%	2%	0%	0%	1%	1%	0%	2%
N	125	71	39	15	47	38	23	11	6	31	30	50	14	0	33	60	32	64	78	49	29

DR15. Do you have a plan detailing the demand reduction actions that your organization will take in response to [PROGRAM] events?	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
Yes	39%	42%	34%	57%	49%	39%	35%	48%	43%	41%	33%	45%	33%	100%	38%	41%	37%	48%	37%	41%	35%
No	59%	57%	64%	43%	49%	61%	64%	52%	57%	58%	65%	55%	64%	0%	61%	58%	60%	51%	62%	59%	63%
DON'T KNOW	1%	1%	2%	0%	2%	0%	2%	0%	0%	2%	2%	0%	2%	0%	1%	1%	2%	1%	1%	0%	2%
N	298	142	121	35	68	63	136	17	14	78	80	100	39	1	90	146	62	99	230	80	150

DR17. Does your load reduction plan differ from how your have responded to Demand Reduction events this summer?	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
Yes	14%	16%	11%	12%	3%	21%	16%	37%	0%	30%	13%	3%	15%	0%	27%	10%	5%	9%	19%	25%	13%
No	83%	84%	78%	88%	97%	79%	69%	63%	100%	57%	87%	97%	85%	0%	73%	87%	87%	91%	75%	75%	75%
DON'T KNOW	4%	0%	11%	0%	0%	0%	15%	0%	0%	13%	0%	0%	0%	0%	0%	4%	8%	0%	6%	0%	12%
N	85	43	24	18	31	24	16	8	6	22	21	35	7	0	27	38	20	45	54	32	22

TECHNICAL ASSISTANCE

DR20. Did you take advantage of any utility assistance services to help your organization prepare for demand response events?	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
Yes	24%	23%	24%	35%	26%	29%	22%	30%	20%	24%	24%	23%	27%	0%	24%	20%	35%	26%	24%	29%	22%
No	74%	76%	75%	62%	73%	71%	77%	58%	80%	76%	75%	76%	68%	100%	73%	79%	65%	71%	75%	68%	77%
DON'T KNOW	1%	1%	1%	3%	2%	0%	1%	12%	0%	0%	1%	1%	6%	0%	3%	1%	0%	3%	1%	2%	1%
N	298	142	121	35	68	63	136	17	14	78	80	100	39	1	90	146	62	99	230	80	150

DR21. What type of utility assistance did you utilize?	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
Technical assistance	30%	31%	22%	54%	42%	29%	23%	20%	69%	47%	20%	20%	38%	.	27%	35%	25%	40%	26%	27%	26%
Participant meetings/seminars/workshops	35%	28%	41%	30%	33%	55%	31%	20%	0%	29%	39%	33%	43%	.	37%	30%	40%	27%	35%	47%	29%
Utility rep	8%	16%	4%	0%	12%	0%	9%	20%	0%	12%	9%	4%	9%	.	8%	11%	4%	13%	7%	4%	8%
Website	16%	19%	15%	8%	29%	15%	10%	20%	0%	9%	18%	20%	13%	.	18%	11%	19%	24%	12%	16%	10%
Rebate programs	2%	6%	0%	0%	0%	0%	2%	20%	0%	0%	0%	7%	0%	.	4%	3%	0%	4%	3%	4%	2%
RECORD VERBATIM	6%	3%	10%	0%	0%	5%	10%	0%	0%	7%	5%	9%	0%	.	7%	5%	7%	0%	8%	4%	10%
REFUSED	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	.	0%	0%	0%	0%	0%	0%	0%
DON'T KNOW	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	.	0%	0%	0%	0%	0%	0%	0%
N	74	32	31	11	18	18	30	5	3	18	21	24	11	0	21	31	22	26	56	23	33

DR22. Was the utility assistance useful in helping you fully respond to 2005 event notifications?	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
Yes	83%	81%	82%	92%	88%	95%	75%	80%	100%	81%	83%	90%	71%	0%	85%	82%	83%	87%	82%	92%	76%
No	11%	19%	6%	8%	12%	5%	13%	20%	0%	12%	17%	4%	16%	0%	15%	14%	4%	13%	11%	8%	12%
DON'T KNOW	6%	0%	12%	0%	0%	0%	12%	0%	0%	7%	0%	6%	13%	0%	0%	5%	13%	0%	7%	0%	11%
N	74	32	31	11	18	18	30	5	3	18	21	24	11	0	21	31	22	26	56	23	33

ASSIST. What type of utility assistance would your organization find most useful to help you take demand reduction actions for future [PROGRAM] events?	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
Lower Load Reduction Requirement	5%	4%	4%	10%	6%	2%	4%	9%	9%	7%	3%	6%	0%	.	9%	4%	0%	7%	4%	3%	5%
Provide more training	19%	16%	20%	25%	13%	14%	19%	36%	47%	20%	22%	18%	11%	.	28%	15%	16%	20%	20%	18%	21%
Increase Incentives	19%	15%	21%	27%	17%	20%	19%	36%	9%	20%	12%	26%	18%	.	21%	19%	19%	18%	20%	23%	19%
Notify Additional People	4%	3%	5%	5%	2%	6%	4%	18%	9%	4%	7%	4%	0%	.	4%	6%	0%	5%	5%	8%	4%
Nothing	24%	28%	23%	15%	26%	20%	25%	18%	36%	23%	23%	23%	33%	.	23%	23%	32%	26%	24%	20%	26%
Give notification earlier	7%	11%	5%	0%	7%	14%	6%	0%	0%	9%	5%	10%	0%	.	5%	9%	3%	5%	7%	12%	5%
Provide energy audit/survey	12%	11%	12%	12%	11%	8%	14%	0%	9%	7%	14%	16%	8%	.	6%	16%	7%	9%	12%	7%	13%
Continue what they are doing	3%	4%	2%	0%	2%	4%	3%	0%	0%	5%	2%	1%	3%	.	3%	3%	2%	1%	3%	3%	3%
Real-time monitoring	3%	4%	2%	0%	4%	2%	2%	0%	9%	0%	3%	4%	6%	.	6%	1%	3%	4%	2%	2%	3%
Rebates	4%	4%	4%	0%	7%	6%	2%	0%	0%	4%	1%	5%	6%	.	5%	3%	3%	5%	3%	5%	2%
More specific load data	0%	1%	0%	0%	0%	2%	0%	0%	0%	0%	1%	0%	0%	.	0%	1%	0%	0%	0%	2%	0%
Provide feedback on savings	1%	2%	0%	0%	2%	2%	0%	0%	0%	1%	0%	1%	0%	.	0%	1%	2%	1%	0%	2%	0%
Secondary method of notification	3%	2%	3%	5%	6%	2%	2%	0%	0%	0%	5%	5%	0%	.	3%	2%	4%	4%	2%	2%	2%
Work with APCD to lessen regulations on generators	1%	0%	0%	10%	4%	0%	0%	0%	0%	0%	3%	0%	0%	.	0%	0%	3%	3%	0%	0%	0%
Renewable energy	1%	0%	2%	0%	0%	0%	1%	0%	0%	0%	3%	0%	0%	.	0%	1%	0%	0%	1%	0%	1%
Automated trigger	0%	0%	0%	5%	2%	0%	0%	0%	0%	1%	0%	0%	0%	.	1%	0%	0%	1%	0%	0%	0%
Design assistance	0%	1%	0%	0%	0%	0%	0%	9%	0%	0%	1%	0%	0%	.	0%	1%	0%	1%	0%	2%	0%
Reduce cost of energy	0%	1%	0%	0%	2%	0%	0%	0%	0%	0%	0%	1%	0%	.	1%	0%	0%	1%	0%	0%	0%
Correct software problems	1%	2%	1%	0%	0%	4%	1%	0%	0%	0%	2%	2%	0%	.	1%	1%	2%	0%	1%	3%	1%
RECORD VERBATIM	3%	3%	4%	0%	4%	4%	3%	9%	0%	1%	1%	6%	6%	.	1%	6%	0%	4%	3%	5%	3%
REFUSED	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	.	0%	0%	0%	0%	0%	0%	0%
DON'T KNOW	8%	9%	8%	7%	6%	8%	9%	27%	0%	9%	12%	2%	15%	.	10%	8%	7%	8%	9%	11%	8%
N	211	115	78	18	53	49	88	11	10	60	56	68	27	0	57	108	46	74	158	60	98

TA1. How familiar is your organization with [UTILITY'S] Technical Assistance and Incentive program?	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
Very familiar	25%	23%	25%	35%	28%	31%	23%	9%	29%	35%	16%	22%	27%	0%	30%	20%	33%	26%	24%	27%	23%
Somewhat familiar	50%	50%	50%	48%	49%	41%	51%	64%	53%	50%	48%	56%	37%	0%	42%	58%	37%	52%	50%	45%	52%
Not at all familiar	25%	27%	24%	17%	23%	29%	24%	27%	18%	15%	36%	19%	36%	0%	28%	21%	30%	23%	25%	28%	24%
DON'T KNOW	1%	0%	2%	0%	0%	0%	1%	0%	0%	0%	0%	3%	0%	0%	0%	1%	0%	0%	1%	0%	1%
N	211	115	78	18	53	49	88	11	10	60	56	68	27	0	57	108	46	74	158	60	98

TA2. How likely are you to utilize the new Technical Assistance and Incentive program?	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
Very likely	39%	36%	40%	42%	44%	40%	35%	50%	43%	39%	34%	41%	40%	0%	37%	38%	41%	45%	37%	42%	36%
Somewhat likely	39%	37%	38%	58%	34%	37%	41%	38%	57%	33%	51%	39%	33%	0%	46%	37%	39%	38%	41%	37%	42%
Neither Likely nor unlikely	4%	4%	4%	0%	5%	3%	4%	0%	0%	1%	0%	8%	4%	0%	4%	4%	0%	4%	3%	2%	4%
Somewhat unlikely	9%	10%	10%	0%	10%	11%	10%	0%	0%	12%	7%	6%	13%	0%	8%	11%	5%	7%	9%	9%	9%
Not at all likely	8%	11%	7%	0%	5%	9%	11%	0%	0%	12%	7%	5%	9%	0%	4%	8%	13%	4%	9%	7%	10%
DON'T KNOW	1%	2%	0%	0%	2%	0%	0%	13%	0%	1%	0%	1%	0%	0%	0%	1%	2%	3%	1%	2%	0%
N	157	84	58	15	41	35	65	8	8	49	37	53	18	0	40	85	32	57	116	43	73

REASONS FOR PARTICIPATION

ES12A. How significant a reasons is ….Being a good corporate citizen	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
1 INSIGNIFICANT	5%	5%	6%	3%	4%	6%	6%	0%	0%	4%	3%	7%	8%	0%	4%	7%	3%	3%	5%	5%	6%
2	4%	3%	4%	3%	3%	6%	3%	0%	7%	3%	3%	5%	2%	0%	6%	3%	1%	3%	4%	5%	3%
3	26%	22%	31%	14%	18%	17%	33%	12%	21%	32%	24%	28%	10%	0%	22%	27%	27%	17%	28%	16%	32%
4	29%	32%	26%	30%	37%	31%	23%	52%	28%	32%	32%	27%	22%	0%	25%	33%	24%	39%	27%	36%	23%
5 EXTREMELY SIGNIFICANT	34%	36%	29%	48%	36%	39%	30%	30%	43%	29%	35%	29%	51%	100%	36%	28%	43%	36%	33%	37%	31%
DON'T KNOW	3%	1%	5%	3%	2%	0%	5%	5%	0%	0%	3%	4%	7%	0%	6%	2%	2%	2%	4%	1%	5%
Mean	3.85	3.92	3.72	4.22	4.01	3.91	3.72	4.19	4.07	3.79	3.95	3.70	4.13	5.00	3.89	3.74	4.05	4.04	3.81	3.96	3.75
N	298	142	121	35	68	63	136	17	14	78	80	100	39	1	90	146	62	99	230	80	150

ES12B. How significant a reasons is ….Avoiding rolling blackouts	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
1 INSIGNIFICANT	6%	9%	5%	0%	3%	6%	6%	18%	7%	8%	1%	8%	8%	0%	9%	4%	9%	6%	7%	9%	7%
2	4%	4%	5%	0%	2%	6%	5%	0%	0%	6%	7%	3%	0%	0%	1%	5%	5%	1%	5%	5%	5%
3	13%	12%	15%	10%	8%	20%	15%	0%	7%	15%	16%	13%	10%	0%	14%	14%	11%	6%	15%	15%	15%
4	21%	14%	25%	32%	18%	29%	21%	10%	14%	16%	14%	32%	17%	0%	19%	22%	21%	16%	22%	25%	21%
5 EXTREMELY SIGNIFICANT	54%	61%	47%	54%	68%	39%	51%	66%	72%	55%	61%	42%	62%	100%	54%	53%	53%	68%	50%	45%	52%
DON'T KNOW	2%	1%	2%	3%	2%	0%	2%	5%	0%	0%	1%	2%	3%	0%	3%	1%	2%	2%	1%	1%	2%
Mean	4.13	4.15	4.06	4.45	4.48	3.89	4.06	4.12	4.42	4.05	4.29	3.99	4.30	5.00	4.11	4.16	4.08	4.42	4.04	3.93	4.08
N	298	142	121	35	68	63	136	17	14	78	80	100	39	1	90	146	62	99	230	80	150

ES12C. How significant a reasons is ….The amount of potential bill savings	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
1 INSIGNIFICANT	10%	10%	10%	8%	5%	8%	12%	12%	0%	12%	6%	11%	10%	0%	5%	12%	10%	6%	11%	9%	12%
2	8%	12%	7%	0%	5%	8%	8%	28%	7%	9%	6%	10%	8%	0%	7%	12%	2%	9%	9%	12%	8%
3	14%	13%	13%	29%	11%	17%	16%	0%	20%	17%	18%	10%	13%	0%	16%	11%	22%	10%	15%	13%	16%
4	20%	24%	18%	8%	14%	27%	20%	18%	7%	25%	22%	19%	7%	0%	12%	26%	15%	14%	21%	25%	20%
5 EXTREMELY SIGNIFICANT	45%	41%	49%	46%	64%	38%	40%	30%	65%	35%	46%	47%	59%	100%	55%	38%	50%	59%	41%	37%	42%
DON'T KNOW	2%	1%	3%	8%	0%	2%	3%	12%	0%	1%	2%	3%	3%	0%	4%	2%	1%	2%	3%	4%	2%
Mean	3.84	3.75	3.91	3.90	4.27	3.82	3.70	3.32	4.31	3.62	3.97	3.85	4.00	5.00	4.08	3.67	3.96	4.14	3.73	3.72	3.74
N	298	142	121	35	68	63	136	17	14	78	80	100	39	1	90	146	62	99	230	80	150

ES12D. How significant a reasons is ….Being able to participate in the program without significantly affecting your business operations.	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
1 INSIGNIFICANT	6%	4%	8%	3%	4%	0%	9%	6%	0%	2%	7%	8%	8%	0%	8%	4%	8%	4%	6%	1%	8%
2	2%	1%	3%	0%	0%	1%	4%	0%	0%	2%	0%	5%	0%	0%	3%	3%	0%	0%	3%	1%	3%
3	14%	16%	13%	14%	16%	15%	13%	21%	7%	15%	14%	13%	15%	0%	16%	13%	13%	16%	13%	16%	12%
4	27%	26%	28%	24%	33%	30%	26%	6%	21%	24%	23%	35%	22%	0%	16%	30%	33%	27%	25%	25%	26%
5 EXTREMELY SIGNIFICANT	48%	53%	43%	56%	45%	54%	45%	61%	72%	55%	54%	36%	52%	100%	55%	47%	42%	51%	49%	55%	46%
DON'T KNOW	3%	1%	5%	3%	2%	0%	4%	5%	0%	2%	3%	4%	3%	0%	3%	3%	4%	2%	3%	1%	4%
Mean	4.12	4.24	3.98	4.36	4.16	4.36	3.98	4.23	4.64	4.30	4.21	3.90	4.14	5.00	4.10	4.15	4.07	4.24	4.11	4.33	4.02
N	298	142	121	35	68	63	136	17	14	78	80	100	39	1	90	146	62	99	230	80	150

ES12E. How significant a reasons is ….Receiving community recognition for your participation	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
1 INSIGNIFICANT	35%	35%	32%	52%	45%	31%	32%	25%	51%	32%	36%	33%	43%	100%	36%	35%	33%	44%	33%	30%	33%
2	16%	16%	17%	12%	17%	17%	15%	25%	12%	15%	13%	22%	10%	0%	21%	16%	10%	17%	16%	19%	15%
3	25%	23%	29%	14%	11%	32%	29%	8%	18%	28%	27%	23%	24%	0%	21%	29%	23%	12%	29%	28%	29%
4	5%	7%	5%	3%	5%	0%	6%	25%	6%	3%	9%	4%	5%	0%	2%	7%	5%	7%	5%	4%	6%
5 EXTREMELY SIGNIFICANT	5%	5%	5%	8%	8%	7%	4%	8%	0%	9%	2%	4%	7%	0%	9%	2%	8%	7%	5%	7%	4%
DON'T KNOW	13%	14%	13%	11%	14%	12%	13%	8%	13%	12%	14%	13%	12%	0%	10%	11%	21%	13%	13%	12%	13%
Mean	2.19	2.19	2.24	2.00	1.97	2.24	2.25	2.64	1.94	2.36	2.16	2.12	2.14	1.00	2.23	2.13	2.32	2.06	2.25	2.32	2.23
N	263	126	106	31	64	57	117	12	13	67	76	85	34	1	80	125	58	89	199	69	130

ES12EE. Have the financial incentives associated with the program met your expectations?	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
Yes	41%	39%	37%	71%	59%	36%	36%	38%	57%	37%	40%	41%	52%	100%	43%	38%	46%	57%	37%	36%	37%
Somewhat	17%	13%	21%	10%	10%	17%	19%	25%	6%	17%	21%	15%	13%	0%	20%	20%	6%	10%	18%	18%	19%
No	21%	24%	22%	8%	12%	24%	24%	25%	12%	25%	21%	20%	15%	0%	22%	23%	15%	13%	23%	24%	23%
DON'T KNOW	21%	25%	20%	11%	20%	23%	20%	13%	25%	21%	18%	24%	20%	0%	15%	18%	33%	20%	21%	22%	21%
N	238	110	98	30	61	52	104	8	13	59	69	78	31	1	76	108	54	82	177	60	117

ES12F. Why is that?	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
Didnt participate	32%	23%	43%	0%	0%	8%	48%	50%	0%	0%	52%	51%	27%	.	52%	20%	34%	8%	37%	14%	46%
Incentive not high enough to part	12%	12%	14%	0%	13%	16%	12%	0%	0%	24%	0%	9%	16%	.	5%	17%	11%	9%	12%	14%	11%
Not much savings	8%	8%	8%	0%	13%	8%	5%	0%	50%	13%	0%	5%	18%	.	11%	8%	0%	17%	7%	6%	7%
Paying more now	4%	4%	5%	0%	20%	0%	0%	50%	0%	8%	6%	0%	0%	.	5%	5%	0%	21%	2%	7%	0%
Cost of energy has gone up	6%	0%	11%	0%	0%	0%	9%	0%	0%	0%	10%	9%	0%	.	0%	10%	0%	0%	6%	0%	9%
Incentive too low	16%	23%	8%	35%	13%	16%	18%	0%	0%	21%	12%	19%	0%	.	5%	21%	18%	9%	16%	14%	17%
Cost us more than we save	3%	4%	3%	0%	13%	8%	0%	0%	0%	5%	0%	6%	0%	.	0%	6%	0%	9%	2%	6%	0%
Generator fines	2%	4%	0%	0%	0%	0%	3%	0%	0%	5%	0%	0%	0%	.	0%	0%	10%	0%	2%	0%	3%
Unaware of them	3%	0%	5%	0%	0%	0%	5%	0%	0%	8%	0%	0%	0%	.	0%	5%	0%	0%	3%	0%	4%
Other	7%	7%	9%	0%	0%	23%	0%	.	0%	14%	0%	0%	38%	.	16%	0%	0%	0%	8%	23%	0%
RECORD VERBATIM	9%	15%	0%	65%	13%	29%	0%	0%	50%	10%	12%	0%	24%	.	11%	7%	15%	17%	9%	25%	3%
REFUSED	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	.	0%	0%	0%	0%	0%	0%	0%
DON'T KNOW	2%	4%	0%	0%	13%	0%	0%	0%	0%	0%	7%	0%	0%	.	0%	0%	11%	9%	0%	0%	0%
N	49	26	21	2	7	12	26	2	2	17	13	14	5	0	16	25	8	11	42	14	28

ES12G. Do you feel that your participation is having a positive effect on [UTILITY]'s ability to maintain system reliability?	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
Yes	68%	75%	61%	76%	86%	73%	56%	100%	77%	65%	75%	62%	74%	100%	69%	68%	68%	87%	63%	78%	58%
Somewhat	10%	8%	11%	8%	3%	9%	14%	0%	0%	8%	10%	14%	0%	0%	4%	12%	12%	2%	12%	7%	13%
No	16%	12%	20%	8%	8%	12%	22%	0%	8%	22%	10%	18%	11%	0%	18%	14%	17%	7%	18%	9%	21%
DON'T KNOW	6%	5%	8%	8%	3%	7%	8%	0%	15%	5%	4%	6%	15%	0%	9%	6%	3%	4%	7%	5%	8%
N	263	123	106	34	64	55	118	13	13	67	73	87	35	1	80	131	52	90	199	68	131

ES12H. Why is that?	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
Unable to participate	66%	43%	81%	35%	15%	45%	76%	.	100%	64%	66%	74%	43%	.	70%	75%	41%	29%	72%	45%	76%
We couldnt reduce much	12%	21%	8%	0%	64%	15%	4%	.	0%	0%	27%	11%	24%	.	7%	5%	30%	54%	6%	15%	4%
Every little bit helps	7%	0%	10%	.	0%	0%	9%	.	0%	0%	0%	0%	60%	.	0%	0%	21%	0%	8%	0%	9%
Reduced our summer loads	9%	7%	11%	0%	0%	0%	12%	.	0%	9%	12%	9%	0%	.	17%	0%	16%	0%	10%	0%	12%
RECORD VERBATIM	11%	25%	5%	0%	0%	16%	12%	.	0%	27%	0%	6%	0%	.	6%	16%	7%	0%	12%	16%	11%
REFUSED	0%	0%	0%	0%	0%	0%	0%	.	0%	0%	0%	0%	0%	.	0%	0%	0%	0%	0%	0%	0%
DON'T KNOW	3%	0%	0%	65%	0%	24%	0%	.	0%	0%	0%	0%	33%	.	0%	0%	14%	0%	3%	24%	0%
N	38	16	20	2	5	6	26	0	1	13	8	13	4	0	12	18	8	6	33	6	27

ES12I. On a 1 to 5 scale, indicate how significant receiving community recognition for your participation is to your organizations decision to participate in the [PROGRAM] program.	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
1 INSIGNIFICANT	33%	34%	32%	24%	27%	38%	37%	0%	0%	30%	17%	42%	44%	0%	35%	34%	23%	21%	34%	34%	34%
2	20%	12%	27%	42%	22%	25%	18%	33%	0%	27%	8%	19%	34%	0%	35%	12%	17%	20%	20%	26%	17%
3	18%	24%	9%	24%	18%	21%	17%	33%	20%	21%	26%	13%	11%	0%	10%	24%	19%	20%	19%	22%	17%
4	20%	20%	24%	0%	19%	8%	23%	0%	60%	19%	33%	17%	0%	0%	9%	27%	19%	23%	20%	8%	26%
5 EXTREMELY SIGNIFICANT	7%	7%	6%	10%	13%	0%	5%	33%	20%	0%	16%	6%	11%	0%	12%	0%	17%	16%	5%	3%	6%
REFUSED	1%	0%	3%	0%	0%	4%	0%	0%	0%	3%	0%	0%	0%	0%	0%	2%	0%	0%	1%	4%	0%
DON'T KNOW	1%	2%	0%	0%	0%	4%	0%	0%	0%	0%	0%	3%	0%	0%	0%	0%	6%	0%	1%	4%	0%
Mean	2.47	2.52	2.44	2.31	2.70	2.00	2.39	3.33	4.00	2.28	3.22	2.23	1.99	.	2.30	2.46	2.88	2.95	2.41	2.15	2.52
N	84	54	21	9	22	24	30	3	5	27	23	26	8	0	26	42	16	30	62	27	35

ES12E. Receiving community recognition for your participation	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
1 INSIGNIFICANT	35%	35%	32%	52%	45%	31%	32%	25%	51%	32%	36%	33%	43%	100%	36%	35%	33%	44%	33%	30%	33%
2	16%	16%	17%	12%	17%	17%	15%	25%	12%	15%	13%	22%	10%	0%	21%	16%	10%	17%	16%	19%	15%
3	25%	23%	29%	14%	11%	32%	29%	8%	18%	28%	27%	23%	24%	0%	21%	29%	23%	12%	29%	28%	29%
4	5%	7%	5%	3%	5%	0%	6%	25%	6%	3%	9%	4%	5%	0%	2%	7%	5%	7%	5%	4%	6%
5 EXTREMELY SIGNIFICANT	5%	5%	5%	8%	8%	7%	4%	8%	0%	9%	2%	4%	7%	0%	9%	2%	8%	7%	5%	7%	4%
DON'T KNOW	13%	14%	13%	11%	14%	12%	13%	8%	13%	12%	14%	13%	12%	0%	10%	11%	21%	13%	13%	12%	13%
Mean	2.19	2.19	2.24	2.00	1.97	2.24	2.25	2.64	1.94	2.36	2.16	2.12	2.14	1.00	2.23	2.13	2.32	2.06	2.25	2.32	2.23
N	263	126	106	31	64	57	117	12	13	67	76	85	34	1	80	125	58	89	199	69	130

CONCERN. What other concerns does your organization have about trying to temporarily reduce summer peak loads through participation in DR programs/tariffs?	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
None	32%	37%	30%	15%	44%	25%	29%	45%	36%	28%	30%	33%	44%	.	29%	34%	30%	43%	29%	28%	30%
Ability to participate	16%	11%	17%	33%	13%	10%	19%	9%	0%	14%	15%	15%	21%	.	12%	16%	18%	11%	16%	10%	18%
Negative impact on production/business	15%	14%	16%	10%	11%	18%	16%	9%	0%	16%	13%	19%	6%	.	12%	18%	9%	9%	16%	17%	15%
Costs/saving money	12%	11%	13%	5%	13%	8%	13%	9%	9%	15%	18%	7%	5%	.	9%	13%	11%	12%	11%	8%	13%
Reliable power	4%	5%	2%	5%	6%	6%	2%	0%	9%	3%	5%	4%	3%	.	7%	2%	3%	5%	3%	5%	3%
Notification process	6%	3%	7%	16%	2%	4%	7%	0%	29%	13%	3%	5%	0%	.	4%	6%	9%	5%	7%	3%	8%
Safety	2%	4%	1%	0%	2%	4%	1%	0%	9%	1%	6%	0%	3%	.	4%	1%	4%	3%	2%	3%	2%
Comfort	2%	3%	1%	0%	0%	6%	1%	0%	0%	3%	2%	2%	0%	.	4%	1%	2%	0%	2%	5%	1%
Saving energy	2%	1%	3%	0%	2%	0%	3%	0%	0%	0%	3%	4%	0%	.	1%	3%	0%	1%	2%	0%	3%
Increasing participation	1%	1%	1%	5%	4%	2%	0%	0%	0%	0%	1%	1%	3%	.	1%	1%	2%	3%	0%	2%	0%
Education/training	1%	1%	1%	10%	2%	2%	0%	0%	20%	2%	0%	2%	0%	.	3%	0%	3%	4%	1%	2%	1%
Having to reduce too often	1%	2%	0%	5%	2%	0%	1%	9%	0%	2%	2%	0%	0%	.	3%	0%	2%	3%	1%	2%	1%
Worth while/needed	1%	1%	2%	0%	2%	0%	1%	0%	0%	1%	3%	0%	0%	.	0%	2%	0%	1%	1%	0%	1%
RECORD VERBATIM	3%	4%	2%	0%	2%	6%	2%	0%	9%	4%	1%	3%	3%	.	3%	2%	5%	3%	3%	5%	3%
REFUSED	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	.	0%	0%	0%	0%	0%	0%	0%
DON'T KNOW	12%	9%	15%	5%	2%	16%	14%	18%	0%	17%	4%	11%	19%	.	14%	12%	9%	4%	14%	17%	13%
N	211	115	78	18	53	49	88	11	10	60	56	68	27	0	57	108	46	74	158	60	98

SATISFACTION RANKINGS

ES14a. Rate your satisfaction with...The process by which you were notified about the DR event	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
Very Satisfied	46%	53%	37%	64%	71%	45%	38%	45%	36%	38%	39%	54%	59%	0%	46%	44%	50%	63%	40%	45%	38%
Somewhat Satisfied	37%	33%	41%	31%	19%	35%	42%	45%	56%	43%	30%	38%	32%	0%	38%	35%	40%	27%	41%	36%	43%
Somewhat Dissatisfied	9%	11%	9%	5%	8%	12%	9%	0%	9%	8%	15%	6%	9%	0%	14%	9%	5%	7%	9%	10%	9%
Very Dissatisfied	4%	2%	6%	0%	2%	4%	5%	0%	0%	8%	6%	0%	0%	0%	1%	5%	4%	2%	4%	3%	5%
DON'T KNOW	4%	2%	7%	0%	0%	4%	6%	9%	0%	3%	10%	3%	0%	0%	1%	7%	2%	1%	5%	5%	5%
N	211	115	78	18	53	49	88	11	10	60	56	68	27	0	57	108	46	74	158	60	98

ES14b. Rate your satisfaction with...The amount of advanced notification	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
Very Satisfied	27%	31%	22%	37%	54%	12%	21%	27%	36%	23%	19%	33%	37%	0%	29%	22%	37%	48%	20%	15%	22%
Somewhat Satisfied	38%	36%	41%	32%	30%	45%	39%	45%	27%	36%	46%	35%	33%	0%	36%	40%	36%	32%	40%	45%	38%
Somewhat Dissatisfied	24%	25%	21%	31%	14%	31%	24%	27%	29%	24%	17%	27%	27%	0%	32%	21%	20%	17%	26%	30%	25%
Very Dissatisfied	7%	7%	7%	0%	2%	8%	8%	0%	9%	11%	9%	2%	3%	0%	3%	9%	5%	3%	8%	7%	8%
DON'T KNOW	5%	2%	9%	0%	0%	4%	8%	0%	0%	5%	9%	4%	0%	0%	0%	9%	2%	0%	6%	3%	7%
N	211	115	78	18	53	49	88	11	10	60	56	68	27	0	57	108	46	74	158	60	98

ES14c1. Rate your satisfaction with...The number of CPP events called	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
Very Satisfied	41%	40%	67%	38%	49%	0%	0%	18%	18%	17%	37%	46%	62%	0%	33%	37%	55%	41%	18%	18%	18%
Somewhat Satisfied	39%	42%	0%	38%	32%	0%	0%	73%	44%	48%	47%	33%	30%	0%	43%	41%	31%	39%	59%	73%	44%
Somewhat Dissatisfied	10%	7%	33%	13%	12%	0%	0%	0%	9%	15%	0%	18%	0%	0%	8%	15%	5%	10%	4%	0%	9%
Very Dissatisfied	5%	4%	0%	12%	4%	0%	0%	0%	20%	14%	0%	4%	8%	0%	12%	4%	0%	5%	10%	0%	20%
REFUSED	1%	2%	0%	0%	0%	0%	0%	0%	9%	6%	0%	0%	0%	0%	0%	0%	4%	1%	4%	0%	9%
DON'T KNOW	4%	5%	0%	0%	4%	0%	0%	9%	0%	0%	16%	0%	0%	0%	4%	4%	5%	4%	5%	9%	0%
N	74	56	3	15	53	0	0	11	10	13	19	29	13	0	24	28	22	74	21	11	10

ES14c2. Rate your satisfaction with...The number of DBP events called	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
Very Satisfied	24%	25%	24%	22%	0%	35%	22%	18%	9%	17%	17%	33%	41%	0%	32%	24%	15%	14%	24%	32%	21%
Somewhat Satisfied	51%	49%	53%	56%	0%	51%	50%	64%	64%	62%	43%	48%	50%	0%	47%	49%	66%	64%	51%	53%	51%
Somewhat Dissatisfied	10%	14%	7%	0%	0%	6%	11%	9%	9%	5%	20%	6%	4%	0%	8%	8%	17%	9%	10%	7%	11%
Very Dissatisfied	2%	1%	2%	22%	0%	0%	2%	9%	0%	3%	1%	2%	0%	0%	2%	3%	0%	5%	2%	2%	2%
DON'T KNOW	13%	10%	15%	0%	0%	8%	15%	0%	18%	13%	19%	10%	5%	0%	12%	17%	2%	9%	13%	7%	15%
N	158	79	75	4	0	49	88	11	10	53	45	45	15	0	41	89	28	21	158	60	98

ES14d1. Rate your satisfaction with...The duration of the CPP events called	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
Very Satisfied	38%	38%	67%	31%	44%	0%	0%	18%	27%	22%	21%	46%	61%	0%	36%	37%	41%	38%	22%	18%	27%
Somewhat Satisfied	49%	49%	33%	50%	45%	0%	0%	73%	44%	57%	63%	43%	31%	0%	48%	52%	45%	49%	59%	73%	44%
Somewhat Dissatisfied	3%	2%	0%	6%	2%	0%	0%	0%	9%	6%	0%	4%	0%	0%	0%	0%	9%	3%	4%	0%	9%
Very Dissatisfied	3%	0%	0%	12%	0%	0%	0%	0%	20%	14%	0%	0%	0%	0%	8%	0%	0%	3%	10%	0%	20%
DON'T KNOW	8%	11%	0%	0%	9%	0%	0%	9%	0%	0%	16%	7%	8%	0%	8%	11%	5%	8%	5%	9%	0%
N	74	56	3	15	53	0	0	11	10	13	19	29	13	0	24	28	22	74	21	11	10

ES14d2. Rate your satisfaction with...The duration of the DBP events called	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
Very Satisfied	24%	22%	26%	0%	0%	43%	19%	18%	18%	15%	20%	31%	45%	0%	28%	25%	18%	18%	24%	39%	19%
Somewhat Satisfied	48%	53%	42%	100%	0%	35%	49%	73%	56%	61%	46%	39%	33%	0%	47%	43%	62%	64%	48%	41%	50%
Somewhat Dissatisfied	5%	4%	6%	0%	0%	10%	4%	0%	0%	3%	4%	10%	4%	0%	4%	5%	8%	0%	5%	8%	4%
Very Dissatisfied	2%	1%	2%	0%	0%	2%	1%	9%	0%	3%	1%	2%	0%	0%	2%	2%	2%	5%	2%	3%	1%
REFUSED	1%	1%	0%	0%	0%	0%	1%	0%	0%	0%	2%	0%	0%	0%	0%	1%	0%	0%	1%	0%	1%
DON'T KNOW	21%	18%	23%	0%	0%	10%	25%	0%	27%	18%	27%	18%	18%	0%	20%	24%	10%	13%	21%	8%	25%
N	158	79	75	4	0	49	88	11	10	53	45	45	15	0	41	89	28	21	158	60	98

ES14e. Rate your satisfaction with...The program-related customer service you received from your utility	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
Very Satisfied	53%	55%	49%	72%	72%	59%	47%	36%	44%	51%	40%	65%	56%	0%	48%	51%	66%	63%	49%	55%	47%
Somewhat Satisfied	32%	37%	30%	21%	17%	26%	36%	55%	56%	34%	40%	22%	35%	0%	34%	32%	30%	27%	36%	31%	38%
Somewhat Dissatisfied	4%	4%	5%	0%	4%	8%	4%	9%	0%	6%	6%	4%	0%	0%	7%	5%	0%	4%	5%	8%	3%
Very Dissatisfied	1%	1%	1%	0%	2%	2%	0%	0%	0%	0%	0%	1%	3%	0%	1%	0%	2%	1%	0%	2%	0%
DON'T KNOW	9%	3%	15%	7%	6%	4%	13%	0%	0%	8%	14%	7%	6%	0%	9%	12%	2%	4%	10%	3%	12%
N	211	115	78	18	53	49	88	11	10	60	56	68	27	0	57	108	46	74	158	60	98

ES14f. Rate your satisfaction with...The higher rates you paid for not reducing load	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
Very Satisfied	8%	9%	0%	6%	9%	0%	0%	0%	9%	0%	5%	11%	16%	0%	4%	10%	9%	8%	4%	0%	9%
Somewhat Satisfied	28%	36%	0%	6%	28%	0%	0%	9%	44%	15%	26%	20%	61%	0%	24%	34%	23%	28%	27%	9%	44%
Somewhat Dissatisfied	28%	21%	67%	44%	23%	0%	0%	55%	29%	58%	25%	26%	8%	0%	31%	23%	31%	28%	42%	55%	29%
Very Dissatisfied	23%	20%	0%	38%	26%	0%	0%	18%	9%	21%	32%	24%	8%	0%	21%	28%	19%	23%	14%	18%	9%
DON'T KNOW	14%	14%	33%	6%	14%	0%	0%	18%	9%	6%	13%	20%	8%	0%	20%	5%	18%	14%	14%	18%	9%
N	74	56	3	15	53	0	0	11	10	13	19	29	13	0	24	28	22	74	21	11	10

ES14g1. Rate your satisfaction with...The amount of the bill credit offered for participating in the CPP program	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
Very Satisfied	27%	23%	33%	37%	23%	0%	0%	27%	47%	28%	22%	34%	16%	0%	36%	19%	26%	27%	37%	27%	47%
Somewhat Satisfied	45%	49%	0%	44%	48%	0%	0%	36%	36%	34%	48%	48%	47%	0%	32%	48%	56%	45%	36%	36%	36%
Somewhat Dissatisfied	12%	11%	33%	13%	14%	0%	0%	9%	9%	22%	10%	8%	14%	0%	13%	18%	5%	12%	9%	9%	9%
Very Dissatisfied	3%	4%	0%	0%	2%	0%	0%	9%	0%	0%	5%	0%	8%	0%	4%	3%	0%	3%	5%	9%	0%
DON'T KNOW	14%	14%	33%	6%	14%	0%	0%	18%	9%	16%	15%	11%	16%	0%	16%	12%	13%	14%	14%	18%	9%
N	74	56	3	15	53	0	0	11	10	13	19	29	13	0	24	28	22	74	21	11	10

ES14g2. Rate your satisfaction with...The amount of incentives offered for participating in the DBP program	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
Very Satisfied	17%	18%	17%	33%	0%	16%	16%	18%	38%	11%	10%	26%	31%	0%	25%	11%	29%	28%	17%	17%	18%
Somewhat Satisfied	45%	46%	44%	67%	0%	49%	44%	45%	36%	54%	42%	38%	47%	0%	48%	45%	43%	41%	45%	48%	44%
Somewhat Dissatisfied	20%	22%	20%	0%	0%	20%	21%	18%	9%	21%	20%	20%	17%	0%	18%	21%	19%	14%	20%	20%	20%
Very Dissatisfied	5%	7%	4%	0%	0%	10%	4%	9%	0%	7%	3%	5%	4%	0%	2%	8%	0%	5%	5%	10%	3%
DON'T KNOW	12%	7%	16%	0%	0%	4%	15%	9%	18%	7%	24%	12%	0%	0%	8%	15%	10%	13%	12%	5%	15%
N	158	79	75	4	0	49	88	11	10	53	45	45	15	0	41	89	28	21	158	60	98

OVERALL SATISFACTION AND FUTURE PARTICIPATION

ES15_CPP. Overall, how satisfied are you with your participation in the CPP program this past summer?	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
1	46%	45%	19%	58%	50%	0%	0%	36%	37%	23%	42%	53%	56%	100%	48%	42%	50%	46%	36%	36%	37%
2	44%	45%	63%	36%	40%	0%	0%	54%	53%	64%	47%	39%	35%	0%	39%	47%	46%	44%	53%	54%	53%
3	6%	8%	0%	3%	7%	0%	0%	0%	10%	4%	6%	7%	10%	0%	9%	6%	3%	6%	5%	0%	10%
4	1%	0%	19%	0%	2%	0%	0%	0%	0%	8%	0%	0%	0%	0%	0%	3%	0%	1%	0%	0%	0%
5	2%	2%	0%	3%	1%	0%	0%	10%	0%	0%	5%	2%	0%	0%	4%	2%	0%	2%	5%	10%	0%
N	129	89	6	34	90	0	0	20	19	20	38	49	21	1	47	51	31	129	39	20	19

ES16_CPP. Why is that?	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
Avoiding blackouts	16%	13%	19%	27%	18%	.	.	11%	11%	8%	12%	17%	24%	100%	20%	10%	22%	16%	11%	11%	11%
Saving money	6%	7%	0%	3%	6%	.	.	6%	5%	6%	3%	8%	5%	0%	7%	4%	6%	6%	6%	6%	5%
Ease of use	12%	11%	37%	6%	10%	.	.	29%	5%	28%	16%	8%	0%	0%	6%	19%	7%	12%	17%	29%	5%
Good program	13%	13%	0%	18%	17%	.	.	0%	5%	5%	19%	8%	19%	100%	14%	7%	22%	13%	3%	0%	5%
Program fine, we have kinks to work out	2%	2%	0%	3%	2%	.	.	6%	0%	0%	0%	4%	5%	0%	0%	2%	6%	2%	3%	6%	0%
Doing what we can	11%	11%	0%	12%	10%	.	.	11%	16%	21%	6%	10%	14%	0%	13%	10%	10%	11%	14%	11%	16%
No feedback from utility	3%	5%	0%	0%	2%	.	.	6%	5%	5%	3%	5%	0%	0%	0%	6%	4%	3%	6%	6%	5%
Participating is good	6%	1%	32%	12%	6%	.	100%	0%	0%	8%	2%	6%	10%	0%	2%	8%	8%	5%	4%	0%	9%
Saves equipment	7%	9%	0%	0%	7%	.	.	6%	5%	11%	6%	4%	10%	0%	5%	8%	7%	7%	6%	6%	5%
Can monitor usage everyday	9%	7%	32%	6%	8%	.	100%	11%	0%	0%	17%	8%	5%	0%	4%	13%	8%	8%	10%	11%	9%
Doesn't effect business	3%	3%	0%	0%	2%	.	.	6%	0%	0%	3%	2%	5%	0%	3%	4%	0%	3%	3%	6%	0%
Need more notice	2%	2%	0%	0%	1%	.	.	6%	0%	0%	3%	0%	5%	0%	3%	2%	0%	2%	3%	6%	0%
Saving energy	2%	2%	0%	0%	1%	.	.	0%	5%	0%	3%	2%	0%	0%	0%	2%	4%	2%	3%	0%	5%
Some problems still to be fixed	2%	2%	0%	3%	3%	.	.	0%	0%	0%	0%	6%	0%	0%	4%	2%	0%	2%	0%	0%	0%
RECORD VERBATIM	17%	15%	13%	24%	19%	.	0%	11%	14%	12%	16%	22%	13%	0%	15%	15%	24%	17%	11%	11%	11%
REFUSED	2%	2%	7%	0%	1%	.	.	3%	5%	0%	6%	1%	0%	0%	2%	3%	0%	2%	4%	3%	5%
DON'T KNOW	2%	2%	0%	0%	1%	.	.	0%	5%	0%	3%	2%	0%	0%	5%	0%	0%	2%	3%	0%	5%
N	126	87	6	33	89	0	0	18	19	20	36	48	21	1	45	50	31	126	37	18	19

ES17_CPP. Do you have any suggestions for improving the CPP program?	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
NO SUGGESTIONS	46%	55%	0%	25%	45%	.	.	55%	44%	19%	63%	44%	54%	.	47%	45%	46%	46%	49%	55%	44%
earlier notification	9%	5%	67%	6%	10%	.	.	0%	9%	23%	13%	4%	0%	.	4%	17%	4%	9%	4%	0%	9%
more feedback	7%	5%	36%	0%	4%	.	100%	0%	9%	14%	11%	4%	0%	.	0%	4%	17%	4%	14%	0%	26%
more information	8%	9%	0%	6%	9%	.	.	9%	0%	6%	0%	11%	16%	.	12%	4%	9%	8%	5%	9%	0%
multiple means of notification	4%	2%	33%	6%	4%	.	.	9%	0%	0%	5%	8%	0%	.	0%	5%	9%	4%	5%	9%	0%
increase incentives	3%	2%	0%	6%	2%	.	.	9%	0%	0%	5%	4%	0%	.	0%	3%	5%	3%	5%	9%	0%
improve website monitoring	4%	6%	0%	0%	6%	.	.	0%	0%	7%	0%	4%	8%	.	0%	4%	9%	4%	0%	0%	0%
billing issues	4%	4%	33%	0%	4%	.	.	9%	0%	0%	5%	5%	8%	.	4%	8%	0%	4%	5%	9%	0%
demand reduction seemed unnecessary	3%	2%	0%	6%	2%	.	.	0%	9%	7%	0%	3%	0%	.	4%	3%	0%	3%	4%	0%	9%
communication	3%	2%	0%	6%	4%	.	.	0%	0%	7%	5%	0%	0%	.	4%	4%	0%	3%	0%	0%	0%
help us upgrade system	3%	0%	0%	13%	4%	.	.	0%	0%	0%	0%	7%	0%	.	0%	0%	9%	3%	0%	0%	0%
more education	4%	5%	0%	0%	2%	.	.	9%	9%	6%	0%	0%	14%	.	8%	3%	0%	4%	9%	9%	9%
build a power plant	3%	0%	0%	12%	0%	.	.	0%	20%	14%	0%	0%	0%	.	8%	0%	0%	3%	10%	0%	20%
get AQCB to let us use our generators	1%	2%	0%	0%	0%	.	.	0%	9%	0%	0%	3%	0%	.	0%	0%	4%	1%	4%	0%	9%
get more participants	1%	0%	0%	6%	2%	.	.	0%	0%	0%	0%	4%	0%	.	4%	0%	0%	1%	0%	0%	0%
RECORD VERBATIM	4%	4%	0%	6%	6%	.	0%	0%	0%	7%	0%	7%	0%	.	4%	7%	0%	4%	0%	0%	0%
REFUSED	0%	0%	0%	0%	0%	.	.	0%	0%	0%	0%	0%	0%	.	0%	0%	0%	0%	0%	0%	0%
DON'T KNOW	1%	2%	0%	0%	0%	.	.	9%	0%	0%	5%	0%	0%	.	4%	0%	0%	1%	5%	9%	0%
N	74	56	3	15	53	0	0	11	10	13	19	29	13	0	24	28	22	74	21	11	10

ES20_DBP. Overall, how satisfied are you with your participation in the DBP program this past summer?	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
1	24%	23%	24%	29%	0%	40%	17%	36%	21%	18%	25%	24%	39%	0%	23%	21%	33%	29%	24%	39%	17%
2	45%	55%	39%	36%	0%	47%	45%	54%	37%	48%	42%	47%	42%	0%	43%	45%	49%	46%	45%	48%	44%
3	18%	15%	20%	12%	0%	10%	22%	5%	16%	16%	17%	22%	10%	0%	19%	19%	11%	10%	18%	9%	21%
4	5%	3%	6%	12%	0%	3%	6%	5%	0%	8%	6%	2%	5%	0%	11%	2%	4%	3%	5%	4%	5%
5	8%	4%	11%	12%	0%	0%	11%	0%	26%	11%	10%	5%	5%	0%	4%	12%	3%	12%	8%	0%	12%
N	292	140	137	15	0	87	166	20	19	94	81	89	28	0	85	154	53	39	292	107	185

ES21_DBP. And why do you say that?	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
Avoiding blackouts	5%	4%	6%	0%	.	11%	2%	10%	0%	6%	2%	4%	8%	.	5%	4%	6%	6%	5%	11%	2%
Saving money	7%	5%	9%	0%	.	16%	5%	0%	0%	13%	3%	5%	6%	.	5%	10%	3%	0%	7%	13%	4%
Ease of use	10%	14%	6%	7%	100%	16%	6%	5%	15%	16%	5%	9%	3%	.	6%	10%	15%	12%	9%	14%	7%
Good program	5%	6%	4%	0%	.	9%	3%	5%	7%	5%	4%	6%	3%	.	6%	5%	4%	6%	5%	8%	3%
Program fine, we have kinks to work out	36%	29%	42%	39%	100%	19%	47%	10%	13%	35%	38%	39%	27%	.	35%	40%	29%	14%	36%	17%	45%
Doing what we can	11%	10%	12%	14%	.	10%	11%	10%	22%	7%	11%	11%	25%	.	18%	6%	13%	15%	11%	10%	11%
No feedback from utility	0%	1%	0%	0%	.	1%	0%	0%	0%	0%	0%	1%	0%	.	0%	1%	0%	0%	0%	1%	0%
Participating is good	1%	0%	1%	0%	.	1%	1%	0%	0%	3%	0%	0%	0%	.	0%	1%	3%	0%	1%	1%	1%
Saves equipment	3%	7%	0%	0%	.	5%	0%	15%	15%	4%	4%	3%	0%	.	2%	4%	2%	15%	3%	7%	1%
Can monitor usage everyday	2%	1%	2%	0%	.	4%	1%	5%	0%	5%	0%	1%	0%	.	1%	3%	2%	3%	2%	5%	1%
Doesn't effect business	0%	1%	0%	0%	.	0%	0%	5%	0%	0%	1%	0%	0%	.	1%	0%	0%	3%	0%	1%	0%
Need more notice	2%	2%	1%	0%	.	3%	1%	5%	0%	2%	3%	1%	0%	.	0%	3%	0%	3%	2%	4%	1%
Saving energy	1%	2%	1%	7%	.	1%	1%	0%	6%	1%	3%	1%	0%	.	0%	2%	3%	2%	1%	1%	2%
Some problems still to be fixed	1%	1%	1%	0%	.	1%	1%	0%	0%	0%	0%	3%	3%	.	1%	2%	0%	0%	1%	1%	1%
Still working on plan	2%	4%	1%	0%	.	6%	1%	0%	0%	2%	2%	2%	3%	.	4%	1%	3%	0%	2%	5%	1%
Want to be exempt during harvest season	6%	3%	9%	0%	.	5%	7%	5%	0%	7%	8%	2%	10%	.	6%	5%	8%	3%	6%	5%	7%
No reason	5%	5%	6%	7%	.	2%	7%	0%	0%	5%	3%	8%	3%	.	8%	4%	3%	0%	5%	2%	7%
Haven't participated	1%	1%	1%	0%	.	2%	0%	5%	0%	3%	0%	0%	0%	.	0%	1%	3%	3%	1%	3%	0%
RECORD VERBATIM	12%	18%	9%	7%	0%	14%	10%	26%	22%	7%	14%	18%	6%	.	19%	9%	12%	23%	12%	16%	11%
REFUSED	2%	3%	1%	0%	.	1%	1%	3%	7%	1%	2%	2%	3%	.	1%	2%	2%	5%	2%	1%	2%
DON'T KNOW	2%	2%	1%	20%	.	2%	2%	5%	0%	0%	2%	2%	9%	.	1%	1%	7%	3%	2%	2%	2%
N	271	134	124	13	0	87	150	20	14	86	73	85	27	0	81	138	52	34	271	107	164

ES22_DBP. Do you have any suggestions for improving the DBP program?	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
NO SUGGESTIONS	45%	38%	51%	22%	.	39%	49%	18%	44%	39%	56%	34%	69%	.	35%	46%	56%	31%	45%	35%	49%
Increase incentives	8%	10%	8%	0%	.	10%	6%	36%	0%	4%	11%	13%	0%	.	7%	10%	2%	18%	8%	15%	6%
More training/make easier to understand	8%	9%	8%	22%	.	8%	8%	18%	9%	11%	0%	15%	4%	.	12%	5%	16%	14%	8%	10%	8%
Provide feedback after event	2%	4%	2%	0%	.	4%	1%	9%	0%	3%	1%	3%	0%	.	4%	2%	0%	5%	2%	5%	1%
Make it more flexible	5%	9%	2%	22%	.	8%	5%	0%	0%	4%	7%	7%	0%	.	10%	5%	0%	0%	5%	7%	5%
Generator use	2%	2%	2%	0%	.	0%	2%	0%	9%	5%	0%	1%	0%	.	0%	2%	5%	4%	2%	0%	3%
Education	3%	1%	4%	0%	.	2%	4%	0%	0%	6%	2%	2%	0%	.	6%	3%	0%	0%	3%	2%	3%
Improve website	2%	4%	1%	0%	.	2%	1%	18%	0%	1%	3%	1%	0%	.	6%	1%	0%	9%	2%	5%	1%
Build more power plants	1%	0%	2%	0%	.	0%	1%	0%	0%	3%	0%	0%	0%	.	0%	2%	0%	0%	1%	0%	1%
Cant part	1%	0%	2%	0%	.	0%	1%	0%	0%	0%	0%	3%	0%	.	4%	0%	0%	0%	1%	0%	1%
Encourage renewables	1%	0%	2%	0%	.	0%	1%	0%	0%	0%	4%	0%	0%	.	0%	2%	0%	0%	1%	0%	1%
Rep was helpful	0%	1%	0%	0%	.	2%	0%	0%	0%	1%	0%	0%	0%	.	0%	1%	0%	0%	0%	2%	0%
Repeat notice	0%	0%	1%	0%	.	2%	0%	0%	0%	0%	0%	2%	0%	.	2%	0%	0%	0%	0%	2%	0%
Secure internet	1%	0%	0%	22%	.	0%	1%	0%	0%	0%	0%	2%	0%	.	0%	0%	3%	0%	1%	0%	1%
Should be manditory	1%	3%	1%	0%	.	2%	1%	0%	0%	0%	4%	2%	0%	.	2%	2%	0%	0%	1%	2%	1%
Spread out events more	0%	0%	1%	0%	.	2%	0%	0%	0%	1%	0%	0%	0%	.	0%	1%	0%	0%	0%	2%	0%
Will only part in an emergency	1%	0%	0%	33%	.	0%	0%	0%	20%	3%	0%	0%	0%	.	4%	0%	0%	10%	1%	0%	1%
More advanced notice	20%	24%	18%	0%	100%	29%	18%	0%	18%	18%	18%	21%	27%	.	16%	20%	23%	13%	19%	24%	18%
RECORD VERBATIM	3%	4%	3%	0%	0%	2%	4%	9%	0%	1%	4%	6%	0%	.	3%	4%	0%	4%	3%	3%	3%
REFUSED	0%	0%	0%	0%	.	0%	0%	0%	0%	0%	0%	0%	0%	.	0%	0%	0%	0%	0%	0%	0%
DON'T KNOW	2%	3%	2%	0%	.	0%	3%	0%	0%	3%	2%	2%	0%	.	4%	2%	0%	0%	2%	0%	3%
N	158	79	75	4	0	49	88	11	10	53	45	45	15	0	41	89	28	21	158	60	98

ES31. Is your organization familiar with the Base Interruptible Program (BIP)?	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
Very Familiar	12%	6%	19%	0%	6%	25%	12%	0%	0%	18%	6%	11%	16%	0%	9%	16%	7%	4%	14%	20%	11%
Somewhat Familiar	32%	25%	38%	30%	28%	16%	40%	36%	9%	42%	31%	30%	18%	0%	26%	35%	34%	27%	33%	20%	38%
Not at all Familiar	53%	67%	39%	70%	64%	51%	47%	64%	91%	36%	57%	59%	66%	0%	65%	45%	58%	67%	50%	53%	49%
Already Participating	2%	2%	3%	0%	0%	8%	1%	0%	0%	2%	6%	0%	0%	0%	0%	4%	0%	0%	3%	7%	1%
DON'T KNOW	0%	0%	1%	0%	2%	0%	0%	0%	0%	2%	0%	0%	0%	0%	0%	1%	0%	2%	0%	0%	0%
N	211	115	78	18	53	49	88	11	10	60	56	68	27	0	57	108	46	74	158	60	98

ES32. Has your organization seriously consider, somewhat considered or not at all considered participating in the: Base Interruptible Program (BIP)?	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
Seriously Considered	23%	8%	31%	17%	16%	15%	27%	0%	100%	33%	20%	15%	19%	0%	13%	33%	4%	17%	25%	13%	28%
Somewhat Considered	27%	24%	26%	67%	38%	35%	25%	0%	0%	31%	20%	32%	17%	0%	30%	20%	48%	31%	25%	29%	24%
Have not Considered at all	41%	65%	32%	17%	45%	35%	40%	100%	0%	30%	52%	41%	65%	0%	48%	38%	44%	52%	41%	45%	39%
CURRENTLY Participating in BIP	7%	3%	9%	0%	0%	10%	8%	0%	0%	4%	8%	12%	0%	0%	9%	7%	4%	0%	8%	8%	8%
DON'T KNOW	1%	0%	1%	0%	0%	5%	0%	0%	0%	2%	0%	0%	0%	0%	0%	1%	0%	0%	1%	4%	0%
N	85	36	43	6	18	20	42	4	1	35	18	25	7	0	19	49	17	23	67	24	43

ES32a. What do you like about the BIP Program?	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
Saving money	19%	8%	23%	33%	21%	20%	19%	0%	0%	22%	16%	14%	27%	.	8%	20%	27%	17%	19%	17%	19%
Incentives	16%	14%	19%	0%	5%	35%	15%	0%	0%	13%	15%	24%	8%	.	13%	20%	8%	4%	18%	30%	15%
Nothing/I dont	21%	22%	22%	0%	23%	15%	22%	25%	0%	20%	16%	24%	28%	.	28%	20%	17%	23%	21%	16%	22%
Avoid rolling blackouts	6%	6%	7%	0%	5%	5%	7%	0%	0%	0%	8%	9%	19%	.	9%	4%	9%	4%	6%	4%	7%
Lower rates	7%	6%	7%	17%	10%	5%	7%	0%	0%	7%	12%	5%	0%	.	9%	8%	0%	8%	6%	4%	7%
Saving energy	5%	0%	8%	0%	0%	0%	8%	0%	0%	5%	0%	0%	37%	.	0%	6%	9%	0%	6%	0%	8%
Can manage consumption	3%	2%	3%	0%	0%	0%	3%	25%	0%	0%	0%	9%	0%	.	0%	4%	0%	4%	3%	4%	3%
Its adjustable	2%	0%	3%	0%	0%	0%	3%	0%	0%	0%	0%	6%	0%	.	0%	3%	0%	0%	2%	0%	3%
Minimum of entry	1%	3%	0%	0%	0%	5%	0%	0%	0%	2%	0%	0%	0%	.	0%	0%	4%	0%	1%	4%	0%
Not complicated	1%	0%	0%	17%	5%	0%	0%	0%	0%	0%	0%	3%	0%	.	4%	0%	0%	4%	0%	0%	0%
Others can do it	1%	0%	0%	17%	5%	0%	0%	0%	0%	2%	0%	0%	0%	.	4%	0%	0%	4%	0%	0%	0%
Volume reduction	1%	3%	0%	0%	0%	0%	1%	0%	0%	2%	0%	0%	0%	.	0%	1%	0%	0%	1%	0%	1%
Not applicable/cant participate	5%	11%	3%	0%	5%	5%	4%	0%	100%	6%	8%	3%	0%	.	4%	6%	4%	8%	5%	4%	5%
RECORD VERBATIM	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	.	0%	0%	0%	0%	0%	0%	0%
REFUSED	1%	3%	0%	0%	0%	5%	0%	0%	0%	2%	0%	0%	0%	.	0%	1%	0%	0%	1%	4%	0%
DON'T KNOW	18%	28%	13%	17%	27%	10%	16%	50%	0%	24%	28%	8%	0%	.	20%	13%	31%	30%	16%	16%	16%
N	86	37	43	6	19	20	42	4	1	35	18	26	7	0	19	50	17	24	67	24	43

ES32b. What do you dislike about the BIP Program?	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
Cant respond that fast/ notification	19%	22%	17%	33%	33%	20%	16%	0%	0%	9%	28%	29%	8%	.	17%	23%	8%	27%	16%	17%	16%
Does not fit our business	19%	34%	12%	17%	27%	15%	18%	0%	100%	24%	24%	12%	9%	.	22%	20%	12%	26%	17%	13%	19%
Nothing	13%	6%	16%	17%	11%	10%	15%	0%	0%	4%	4%	28%	27%	.	18%	14%	4%	9%	13%	9%	15%
Penalties	7%	6%	8%	0%	0%	15%	7%	0%	0%	9%	12%	3%	0%	.	0%	7%	13%	0%	8%	13%	7%
Interrupts production	7%	3%	9%	0%	0%	10%	8%	0%	0%	7%	8%	0%	27%	.	13%	4%	9%	0%	8%	8%	8%
Hours	6%	5%	5%	17%	11%	0%	5%	25%	0%	5%	15%	3%	0%	.	4%	7%	4%	13%	5%	4%	5%
Load requirement	5%	5%	4%	17%	11%	10%	3%	0%	0%	11%	0%	3%	0%	.	4%	4%	9%	9%	4%	8%	3%
Costs too much to part	1%	0%	1%	0%	0%	5%	0%	0%	0%	0%	4%	0%	0%	.	0%	1%	0%	0%	1%	4%	0%
Difficult to coordinate	1%	3%	0%	0%	0%	5%	0%	0%	0%	0%	0%	3%	0%	.	0%	1%	0%	0%	1%	4%	0%
Incentive too low	1%	3%	0%	0%	0%	5%	0%	0%	0%	2%	0%	0%	0%	.	0%	0%	4%	0%	1%	4%	0%
Intrusive	1%	2%	0%	0%	0%	0%	0%	25%	0%	0%	0%	2%	0%	.	0%	1%	0%	4%	1%	4%	0%
No added incentive	3%	0%	4%	17%	5%	5%	3%	0%	0%	9%	0%	0%	0%	.	8%	3%	0%	4%	3%	4%	3%
Not as good as I-6	2%	0%	3%	0%	0%	0%	3%	0%	0%	5%	0%	0%	0%	.	0%	3%	0%	0%	2%	0%	3%
RECORD VERBATIM	1%	3%	0%	0%	5%	0%	0%	0%	0%	0%	0%	3%	0%	.	0%	1%	0%	4%	0%	0%	0%
REFUSED	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	.	0%	0%	0%	0%	0%	0%	0%
DON'T KNOW	21%	19%	23%	0%	16%	5%	25%	50%	0%	18%	16%	23%	37%	.	21%	16%	36%	20%	22%	12%	24%
N	86	37	43	6	19	20	42	4	1	35	18	26	7	0	19	50	17	24	67	24	43

DR CAPABILITIES

CA3a. At this facility, do you have the ability to view this facility's hourly demand on an in-house energy information system?	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
Yes	39%	34%	44%	37%	30%	33%	46%	27%	27%	51%	37%	36%	27%	0%	37%	42%	36%	29%	42%	32%	45%
No	59%	64%	55%	63%	68%	65%	54%	64%	73%	48%	62%	64%	70%	0%	61%	57%	64%	68%	57%	65%	55%
DON'T KNOW	1%	2%	1%	0%	2%	2%	0%	9%	0%	1%	1%	0%	3%	0%	1%	1%	0%	3%	1%	3%	0%
N	211	115	78	18	53	49	88	11	10	60	56	68	27	0	57	108	46	74	158	60	98

CA3b. Do you have the ability to view this facility's hourly demand on a [UTILITY] provided website?	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
Yes	82%	84%	79%	95%	80%	80%	84%	73%	82%	83%	88%	82%	70%	0%	81%	80%	90%	79%	83%	78%	84%
No	11%	9%	15%	0%	12%	8%	11%	18%	18%	9%	7%	14%	21%	0%	13%	12%	7%	14%	11%	10%	12%
DON'T KNOW	6%	7%	6%	5%	8%	12%	4%	9%	0%	8%	5%	5%	8%	0%	6%	8%	3%	7%	6%	12%	4%
N	211	115	78	18	53	49	88	11	10	60	56	68	27	0	57	108	46	74	158	60	98

FEED1. Have you used the online tool to monitor your electricity usage before or during one of the 2005 events?	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
Yes	56%	60%	48%	65%	59%	69%	43%	79%	52%	57%	52%	56%	59%	0%	54%	60%	51%	61%	55%	71%	44%
No	40%	36%	46%	32%	40%	27%	51%	21%	33%	36%	41%	42%	41%	0%	44%	34%	47%	36%	40%	26%	49%
Don't have Tool	1%	2%	0%	0%	0%	2%	0%	0%	7%	2%	2%	0%	0%	0%	2%	1%	0%	1%	1%	1%	1%
Don't know how to use tool	1%	2%	0%	0%	0%	2%	0%	0%	7%	3%	0%	0%	0%	0%	0%	1%	2%	1%	1%	1%	1%
DON'T KNOW	2%	0%	5%	3%	1%	0%	5%	0%	0%	1%	5%	2%	0%	0%	1%	4%	0%	1%	3%	0%	5%
N	211	111	71	29	59	55	68	15	14	51	56	77	27	0	64	96	51	88	152	70	82

FEED2. Did the tool give you the information necessary to effectively manage your events?	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
Yes	83%	81%	87%	84%	80%	77%	89%	91%	86%	79%	79%	90%	79%	0%	79%	83%	88%	83%	84%	80%	88%
No	16%	18%	13%	11%	18%	23%	11%	0%	14%	18%	18%	10%	21%	0%	18%	17%	10%	14%	15%	18%	12%
DON'T KNOW	1%	1%	0%	5%	2%	0%	0%	9%	0%	3%	2%	0%	0%	0%	3%	0%	3%	3%	1%	2%	0%
N	122	67	38	17	34	38	31	12	7	30	31	44	17	0	35	60	27	53	88	50	38

FEED3. How would you rate the ease of use of the online tool? Would you say it was …	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
Easy	70%	67%	69%	84%	67%	77%	65%	78%	57%	71%	64%	76%	60%	0%	71%	68%	72%	68%	71%	77%	64%
Somewhat Difficult	28%	29%	31%	16%	33%	18%	32%	22%	43%	26%	36%	22%	34%	0%	24%	30%	28%	32%	26%	19%	34%
Very Difficult	2%	4%	0%	0%	0%	5%	3%	0%	0%	3%	0%	2%	6%	0%	6%	2%	0%	0%	3%	4%	2%
N	122	67	38	17	34	38	31	12	7	30	31	44	17	0	35	60	27	53	88	50	38

FEED4. Do you know if anyone else at your organization regularly logs onto the [UTILTY] website to view this facilities hourly demand?	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
Yes	25%	21%	27%	40%	18%	25%	29%	25%	11%	35%	28%	22%	4%	0%	17%	30%	24%	18%	27%	25%	28%
No	73%	78%	71%	60%	82%	75%	69%	75%	78%	65%	72%	74%	96%	0%	83%	68%	74%	81%	71%	75%	70%
DON'T KNOW	1%	1%	2%	0%	0%	0%	2%	0%	11%	0%	0%	4%	0%	0%	0%	2%	2%	1%	2%	0%	2%
N	175	96	62	17	44	40	75	8	8	49	48	59	19	0	46	88	41	60	131	48	83

FEED5. What are the main reasons they use the online tool?	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
To monitor curtailment actions	9%	15%	7%	0%	13%	10%	9%	0%	0%	18%	0%	6%	0%	.	12%	9%	8%	9%	9%	8%	9%
To help place bids	10%	25%	3%	0%	13%	20%	6%	50%	0%	5%	5%	25%	0%	.	0%	14%	8%	18%	10%	25%	6%
To manage energy usage	60%	60%	57%	74%	75%	70%	53%	100%	0%	50%	58%	74%	100%	.	76%	56%	59%	73%	57%	75%	52%
Evaluate/monitor energy usage	28%	28%	29%	26%	44%	20%	26%	0%	100%	27%	42%	17%	0%	.	0%	28%	49%	42%	25%	17%	28%
View system load/forcasts	6%	5%	7%	0%	0%	0%	9%	0%	0%	0%	6%	14%	0%	.	12%	6%	0%	0%	7%	0%	9%
Billing/costs	9%	10%	7%	13%	12%	10%	9%	0%	0%	18%	0%	7%	0%	.	11%	12%	0%	9%	9%	8%	9%
Corporate mandate	2%	0%	0%	13%	12%	0%	0%	0%	0%	0%	0%	6%	0%	.	11%	0%	0%	9%	0%	0%	0%
We dont	2%	5%	0%	0%	0%	10%	0%	0%	0%	4%	0%	0%	0%	.	0%	3%	0%	0%	2%	8%	0%
Record reasons	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	.	0%	0%	0%	0%	0%	0%	0%
REFUSED	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	.	0%	0%	0%	0%	0%	0%	0%
DON'T KNOW	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	.	0%	0%	0%	0%	0%	0%	0%
N	43	20	16	7	8	10	22	2	1	16	13	13	1	0	8	25	10	11	35	12	23

AUTOMATION TECHNOLOGY INVENTORY (FOR DRRC)

AT1.Does this facility have an Energy Management and Control System (EMCS) for centrally controlling some or all of the heating, ventilation, and air conditioning system or other equipment?	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
Yes	38%	39%	35%	60%	48%	37%	33%	55%	56%	49%	40%	29%	35%	0%	56%	27%	48%	50%	36%	40%	35%
No	55%	57%	57%	33%	48%	59%	58%	45%	44%	46%	54%	66%	53%	0%	41%	65%	46%	47%	57%	57%	57%
DON'T KNOW	6%	4%	9%	7%	4%	4%	9%	0%	0%	5%	6%	5%	12%	0%	3%	8%	5%	3%	7%	3%	8%
N	211	115	78	18	53	49	88	11	10	60	56	68	27	0	57	108	46	74	158	60	98

AT1c.Does your EMCS offer the ability to control all of the space temperatures on a "global" basis, that is, can it turn up or down all of the space temperature set points using a simple screen or other centralized action?	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
Yes	38%	41%	32%	50%	42%	33%	30%	67%	84%	34%	42%	34%	50%	0%	49%	26%	41%	52%	37%	41%	35%
No	56%	57%	63%	25%	46%	61%	66%	33%	16%	58%	55%	58%	50%	0%	46%	69%	52%	40%	59%	55%	61%
DON'T KNOW	6%	2%	4%	25%	11%	5%	4%	0%	0%	8%	3%	8%	0%	0%	5%	6%	7%	8%	4%	4%	4%
N	85	45	29	11	26	18	30	6	5	30	23	22	10	0	34	29	22	37	59	24	35

DR7. Did your organization implement any [PROGRAM] load reductions through your EMCS?	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
Yes	33%	28%	36%	40%	29%	38%	34%	34%	21%	24%	49%	31%	21%	0%	52%	15%	33%	29%	34%	37%	32%
No	66%	71%	61%	60%	71%	62%	63%	66%	69%	72%	51%	68%	79%	0%	47%	82%	67%	70%	64%	63%	64%
DON'T KNOW	2%	1%	3%	0%	0%	0%	3%	0%	10%	4%	0%	2%	0%	0%	2%	3%	0%	1%	2%	0%	4%
N	152	79	45	28	47	41	39	15	10	37	41	55	19	0	55	58	39	72	105	56	49

DR8 (formerly EV10a). What level of automation was used to implement your organizations demand reduction actions? Were they….	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
Fully Automated	9%	9%	8%	14%	11%	6%	8%	13%	0%	6%	4%	11%	18%	0%	12%	0%	22%	11%	8%	8%	7%
Partially Automated OR	39%	26%	53%	43%	25%	23%	70%	50%	0%	55%	54%	30%	12%	0%	34%	37%	46%	29%	48%	32%	64%
Manual	52%	65%	39%	43%	64%	71%	21%	38%	100%	40%	42%	59%	70%	0%	54%	63%	32%	60%	45%	60%	28%
N	66	34	25	7	26	17	13	8	2	15	15	28	8	0	17	30	19	36	40	25	15

AT2a.Is your facility's space temperature control system primarily pneumatic, Direct Digital Control, or some of both?	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
Pneumatic	9%	10%	8%	10%	7%	2%	11%	27%	0%	5%	5%	12%	15%	0%	11%	11%	2%	9%	9%	6%	10%
Direct Digital Control	31%	29%	29%	55%	41%	39%	25%	18%	38%	33%	37%	22%	35%	0%	24%	34%	31%	37%	28%	35%	26%
Some of both	37%	37%	40%	15%	33%	29%	40%	36%	44%	38%	38%	34%	36%	0%	37%	31%	49%	35%	37%	30%	40%
REFUSED	2%	2%	3%	0%	0%	0%	4%	9%	0%	0%	1%	6%	0%	0%	2%	3%	2%	1%	3%	2%	3%
DON'T KNOW	22%	23%	21%	20%	19%	31%	21%	9%	18%	23%	19%	25%	14%	0%	26%	21%	17%	18%	22%	27%	20%
N	211	115	78	18	53	49	88	11	10	60	56	68	27	0	57	108	46	74	158	60	98

GENERAL MARKET KNOWLEDGE AND PERCEPTIONS

ES30. As a result of your experience with the [PROGRAM] program(s) this past summer, would you say you are: much more knowledgeable, somewhat more knowledgeable, or no more knowledgeable about managing your energy usage at times of peak demand?	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
Much more nowledgeable	15%	15%	14%	20%	17%	18%	12%	45%	9%	17%	18%	16%	3%	0%	11%	17%	16%	19%	15%	23%	12%
Somewhat more knowledgeable	58%	63%	53%	63%	68%	53%	56%	45%	73%	64%	48%	60%	61%	0%	60%	58%	56%	66%	55%	52%	57%
No more knowledgeable	26%	22%	31%	17%	15%	29%	31%	9%	18%	19%	34%	22%	36%	0%	28%	24%	28%	14%	29%	25%	30%
DON'T KNOW	1%	0%	2%	0%	0%	0%	1%	0%	0%	0%	0%	3%	0%	0%	0%	1%	0%	0%	1%	0%	1%
N	211	115	78	18	53	49	88	11	10	60	56	68	27	0	57	108	46	74	158	60	98

EM4. And over the next three years, does your organization expect wholesale electricity prices to increase, decrease, or stay about the same?	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
Increase	81%	75%	85%	85%	85%	69%	85%	91%	36%	88%	75%	82%	74%	0%	79%	82%	79%	79%	80%	73%	82%
Decrease	5%	5%	6%	0%	4%	8%	5%	0%	9%	2%	7%	4%	12%	0%	6%	5%	6%	4%	6%	7%	5%
Stay about the same	12%	18%	9%	5%	7%	22%	10%	9%	36%	7%	16%	15%	11%	0%	12%	12%	14%	11%	14%	20%	11%
DON'T KNOW	1%	2%	0%	10%	4%	0%	0%	0%	20%	2%	1%	0%	3%	0%	3%	1%	2%	5%	1%	0%	1%
N	211	115	78	18	53	49	88	11	10	60	56	68	27	0	57	108	46	74	158	60	98

EM5. In your organization's view, how likely is it that California's power supplies will be inadequate to meet expected power demand over the next three years? Would you say…	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
Very Likely	28%	32%	26%	17%	33%	31%	27%	9%	18%	42%	21%	18%	35%	0%	30%	28%	25%	28%	27%	27%	27%
Somewhat Likely	40%	39%	40%	42%	35%	39%	39%	64%	64%	38%	55%	33%	29%	0%	34%	41%	42%	43%	41%	43%	40%
Somewhat Unlikely	22%	22%	21%	32%	21%	27%	21%	18%	18%	11%	22%	29%	30%	0%	25%	18%	29%	20%	22%	25%	21%
Very Unlikely	5%	5%	4%	10%	7%	4%	4%	9%	0%	3%	2%	9%	6%	0%	7%	5%	2%	7%	4%	5%	4%
DON'T KNOW	6%	2%	9%	0%	4%	0%	9%	0%	0%	5%	1%	11%	0%	0%	3%	8%	2%	3%	6%	0%	8%
N	211	115	78	18	53	49	88	11	10	60	56	68	27	0	57	108	46	74	158	60	98

EE1. Has your organization participated in any other energy efficiency programs that reduce your overall energy usage or shift your load from peak to off-peak periods in the past two years?	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
Standard Performance Contracting (SPC)	11%	11%	12%	5%	6%	22%	10%	9%	0%	22%	3%	11%	3%	.	12%	10%	11%	5%	12%	20%	9%
Express Efficiency Rebates	5%	7%	3%	5%	7%	8%	3%	9%	0%	6%	3%	6%	3%	.	8%	3%	7%	7%	4%	8%	3%
Energy Efficiency Audits	5%	7%	4%	5%	10%	8%	3%	9%	0%	9%	3%	4%	6%	.	3%	6%	5%	8%	4%	8%	3%

None	47%	50%	43%	48%	52%	41%	44%	55%	82%	24%	49%	60%	58%	.	55%	44%	44%	56%	45%	43%	46%
Yes - non specific	3%	3%	2%	12%	6%	6%	2%	0%	0%	6%	4%	1%	0%	.	1%	6%	0%	4%	3%	5%	2%
Lighting retrofit	8%	7%	10%	0%	2%	6%	11%	9%	0%	5%	9%	9%	9%	.	3%	12%	4%	3%	10%	7%	11%
I-6	5%	0%	9%	0%	0%	0%	9%	0%	0%	8%	6%	3%	0%	.	0%	9%	0%	0%	6%	0%	8%
Rebate program	4%	7%	2%	0%	2%	2%	4%	18%	0%	6%	4%	0%	6%	.	8%	3%	2%	4%	4%	5%	4%
Savings by design	1%	3%	1%	0%	2%	4%	1%	0%	0%	4%	0%	1%	0%	.	3%	0%	3%	1%	1%	3%	1%
550 plus program	0%	1%	0%	0%	0%	0%	0%	9%	0%	1%	0%	0%	0%	.	1%	0%	0%	1%	0%	2%	0%
Retrofit program	2%	4%	0%	5%	2%	2%	2%	0%	0%	4%	2%	1%	0%	.	3%	2%	0%	1%	2%	2%	2%
Shift load off peak	5%	6%	4%	0%	6%	6%	4%	0%	9%	4%	6%	3%	6%	.	3%	5%	5%	6%	4%	5%	4%
In house demand reduction/ conservation	6%	5%	6%	10%	7%	8%	6%	0%	0%	12%	1%	5%	6%	.	5%	8%	3%	5%	6%	7%	5%
EE motors	4%	2%	6%	0%	0%	4%	6%	0%	0%	4%	3%	4%	6%	.	0%	3%	11%	0%	5%	3%	5%
Interruptible	2%	0%	3%	0%	0%	0%	3%	0%	0%	3%	0%	0%	6%	.	0%	1%	4%	0%	2%	0%	3%
Variable freq drives	1%	1%	2%	0%	0%	2%	1%	0%	0%	0%	0%	1%	6%	.	0%	1%	4%	0%	1%	2%	1%
Solar applications	1%	1%	2%	0%	0%	0%	1%	9%	0%	3%	1%	0%	0%	.	0%	0%	5%	1%	1%	2%	1%
BIP	0%	0%	1%	0%	0%	2%	0%	0%	0%	0%	1%	0%	0%	.	0%	1%	0%	0%	0%	2%	0%
CMTC events	0%	0%	1%	0%	0%	2%	0%	0%	0%	0%	0%	1%	0%	.	0%	1%	0%	0%	0%	2%	0%
Cogeneration	0%	0%	0%	5%	2%	0%	0%	0%	0%	0%	0%	1%	0%	.	0%	0%	2%	1%	0%	0%	0%
Compressed air study	0%	1%	0%	0%	2%	0%	0%	0%	0%	1%	0%	0%	0%	.	0%	0%	2%	1%	0%	0%	0%
CPP	0%	1%	0%	0%	2%	0%	0%	0%	0%	1%	0%	0%	0%	.	0%	1%	0%	1%	0%	0%	0%
Design program	1%	0%	2%	0%	0%	0%	1%	0%	0%	3%	0%	0%	0%	.	0%	0%	4%	0%	1%	0%	1%
Downsizing pumps	1%	0%	2%	0%	0%	0%	1%	0%	0%	3%	0%	0%	0%	.	0%	1%	0%	0%	1%	0%	1%
Generator	1%	0%	1%	5%	4%	0%	0%	0%	0%	2%	0%	1%	0%	.	1%	1%	0%	3%	0%	0%	0%
Oakland Energy Partner tune up	0%	1%	0%	0%	0%	0%	0%	9%	0%	1%	0%	0%	0%	.	0%	0%	2%	1%	0%	2%	0%
Room sensors	0%	1%	0%	0%	0%	0%	1%	0%	0%	0%	2%	0%	0%	.	0%	0%	2%	0%	1%	0%	1%
Summer initiative program	1%	0%	2%	0%	0%	0%	1%	0%	0%	3%	0%	0%	0%	.	0%	1%	0%	0%	1%	0%	1%
Thermography program	0%	1%	0%	0%	0%	2%	0%	0%	0%	0%	1%	0%	0%	.	0%	1%	0%	0%	0%	2%	0%
Energy star benchmarking	0%	1%	0%	0%	0%	0%	0%	9%	0%	1%	0%	0%	0%	.	1%	0%	0%	1%	0%	2%	0%
Various grant programs	0%	0%	1%	0%	0%	2%	0%	0%	0%	1%	0%	0%	0%	.	0%	0%	2%	0%	0%	2%	0%
New construction programs	0%	1%	0%	0%	0%	0%	1%	0%	0%	1%	0%	0%	0%	.	2%	0%	0%	0%	1%	0%	1%
Oakland energy partnership	0%	1%	0%	0%	0%	0%	1%	0%	0%	1%	0%	0%	0%	.	2%	0%	0%	0%	1%	0%	1%
LED exit signs	0%	1%	0%	0%	0%	0%	1%	0%	0%	0%	2%	0%	0%	.	0%	0%	2%	0%	1%	0%	1%
RECORD VERBATIM	0%	0%	0%	5%	2%	0%	0%	0%	0%	0%	1%	0%	0%	.	0%	0%	2%	1%	0%	0%	0%
REFUSED	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	.	0%	0%	0%	0%	0%	0%	0%
DON'T KNOW	5%	3%	6%	0%	4%	4%	5%	0%	9%	3%	7%	5%	3%	.	6%	3%	8%	4%	5%	3%	5%
N	211	115	78	18	53	49	88	11	10	60	56	68	27	0	57	108	46	74	158	60	98

FIRMOGRAPHIC CHARACTERISTICS

EC1.What is the main activity performed at this location?	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
Office	10%	14%	7%	5%	6%	8%	10%	27%	18%	10%	13%	6%	12%	0%	21%	6%	7%	10%	11%	11%	10%
Retail (non-food)	1%	0%	1%	5%	2%	2%	0%	0%	0%	1%	0%	1%	0%	0%	3%	0%	0%	1%	0%	2%	0%
College/university	1%	0%	1%	0%	0%	4%	0%	0%	0%	1%	1%	0%	0%	0%	0%	0%	3%	0%	1%	3%	0%
School	5%	8%	3%	5%	17%	4%	2%	0%	0%	1%	6%	8%	6%	0%	2%	0%	23%	12%	2%	3%	2%
Grocery store	1%	1%	2%	0%	2%	0%	1%	0%	0%	0%	0%	0%	9%	0%	5%	0%	0%	1%	1%	0%	1%
Health care/hospital	4%	4%	5%	0%	2%	2%	6%	9%	0%	4%	7%	1%	6%	0%	0%	0%	20%	3%	5%	3%	5%
Hotel or motel	2%	1%	1%	15%	2%	2%	0%	9%	20%	2%	0%	3%	0%	0%	7%	0%	0%	5%	2%	3%	1%
Warehouse	10%	6%	14%	0%	6%	14%	11%	0%	0%	11%	3%	7%	26%	0%	19%	6%	8%	4%	11%	12%	10%
Personal Service	2%	2%	2%	0%	4%	0%	1%	0%	0%	0%	3%	1%	3%	0%	0%	3%	0%	3%	1%	0%	1%
Community Service/Church/Temple/Municipa	2%	1%	2%	12%	2%	0%	3%	0%	0%	1%	0%	5%	0%	0%	5%	0%	4%	1%	2%	0%	3%
Industrial Electronic & Machinery	5%	4%	5%	0%	4%	6%	4%	9%	9%	5%	6%	3%	5%	0%	2%	8%	0%	5%	5%	7%	4%
Industrial Mining. Metals. Stone. Glass.	7%	6%	8%	10%	6%	6%	9%	0%	9%	13%	5%	7%	0%	0%	6%	9%	4%	6%	8%	5%	9%
Industrial Petroleum. Plastic. Rubber an	4%	4%	4%	0%	2%	6%	4%	0%	0%	4%	3%	6%	0%	0%	0%	7%	0%	1%	4%	5%	4%
Other Industrial	15%	14%	17%	10%	13%	8%	19%	18%	0%	15%	17%	19%	6%	0%	3%	26%	3%	12%	16%	10%	18%
Agricultural	3%	4%	2%	0%	2%	6%	2%	0%	0%	4%	4%	1%	0%	0%	3%	3%	2%	1%	3%	5%	2%
Transportation/Telecommunications/Utilit	5%	6%	3%	15%	7%	4%	4%	9%	18%	6%	3%	5%	6%	0%	3%	0%	20%	9%	5%	5%	4%
Manufacturing	14%	11%	16%	12%	12%	16%	14%	9%	18%	13%	12%	16%	12%	0%	5%	23%	0%	12%	14%	15%	14%
Food processing/packaging	5%	6%	4%	0%	4%	6%	4%	9%	0%	1%	10%	5%	0%	0%	4%	6%	0%	4%	5%	7%	4%
Lab/R&D	3%	5%	1%	12%	9%	2%	2%	0%	9%	4%	3%	2%	6%	0%	6%	3%	2%	8%	2%	2%	2%
Other SPECIFY	3%	2%	5%	0%	0%	2%	5%	0%	0%	3%	5%	3%	3%	0%	8%	1%	4%	0%	4%	2%	5%
N	211	115	78	18	53	49	88	11	10	60	56	68	27	0	57	108	46	74	158	60	98

EC2.Approximately how many square feet does your organization occupy in this facility?	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
Less than 10,000 square feet	6%	4%	9%	0%	2%	6%	9%	0%	0%	5%	5%	9%	6%	0%	8%	6%	5%	1%	7%	5%	8%
10,000 but less than 20,000 square feet	4%	5%	3%	5%	4%	2%	5%	0%	0%	3%	1%	5%	9%	0%	3%	5%	2%	3%	4%	2%	5%
20,000 but less than 50,000 square feet	11%	10%	12%	10%	12%	16%	8%	9%	27%	2%	11%	13%	24%	0%	8%	12%	11%	13%	11%	15%	9%
50,000 but less than 100,000 square feet	14%	15%	13%	10%	13%	10%	16%	9%	9%	9%	12%	12%	32%	0%	12%	19%	3%	12%	14%	10%	15%
100,000 but less than 200,000 square fee	18%	17%	18%	22%	25%	14%	16%	27%	9%	12%	14%	28%	14%	0%	16%	20%	14%	23%	16%	16%	16%
200,000 but less than 300,000 square fee	11%	9%	12%	10%	8%	16%	9%	18%	9%	8%	16%	12%	3%	0%	11%	12%	6%	9%	11%	17%	9%
300,000 but less than 400,000 square fee	6%	8%	5%	0%	6%	6%	6%	9%	0%	12%	3%	4%	3%	0%	6%	6%	5%	5%	6%	7%	5%
400,000 but less than 500,000 square fee	3%	2%	4%	5%	4%	4%	3%	0%	0%	5%	6%	0%	0%	0%	4%	2%	4%	3%	3%	3%	3%
Over 500,000 square feet	16%	20%	12%	16%	17%	14%	14%	27%	29%	29%	21%	6%	0%	0%	25%	8%	25%	20%	16%	16%	15%
Ag/Nonfacility - Outdoors	9%	7%	9%	22%	7%	6%	12%	0%	9%	9%	11%	9%	6%	0%	6%	6%	20%	7%	10%	5%	11%
DON'T KNOW	3%	3%	4%	0%	4%	4%	3%	0%	9%	5%	1%	4%	3%	0%	0%	4%	5%	4%	3%	3%	3%
N	211	115	78	18	53	49	88	11	10	60	56	68	27	0	57	108	46	74	158	60	98

EC3.Does your organization.....	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
Own this space	67%	71%	63%	73%	64%	77%	66%	45%	64%	64%	72%	74%	47%	0%	66%	62%	82%	61%	68%	72%	66%
Lease this space	25%	23%	30%	5%	23%	16%	28%	45%	27%	29%	22%	18%	44%	0%	21%	30%	18%	27%	26%	21%	28%
Own a portion and lease the remainder	7%	6%	7%	17%	11%	6%	6%	9%	9%	7%	6%	7%	9%	0%	11%	8%	0%	11%	6%	7%	6%
DON'T KNOW	0%	0%	0%	5%	2%	0%	0%	0%	0%	0%	0%	1%	0%	0%	1%	0%	0%	1%	0%	0%	0%
N	211	115	78	18	53	49	88	11	10	60	56	68	27	0	57	108	46	74	158	60	98

EC5.What percent of your organization's total annual operating costs do energy costs represent?	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
Less than 1 percent	1%	3%	1%	0%	4%	2%	1%	0%	0%	3%	1%	0%	3%	0%	5%	0%	2%	3%	1%	2%	1%
1 to 4 percent	15%	12%	18%	15%	13%	10%	17%	9%	27%	14%	16%	15%	17%	0%	15%	14%	19%	14%	16%	10%	18%
5 to 10 percent	27%	27%	28%	17%	27%	16%	31%	27%	9%	26%	19%	35%	24%	0%	20%	34%	18%	24%	27%	18%	30%
11 TO 25 percent	16%	20%	14%	5%	13%	24%	15%	9%	9%	20%	16%	13%	11%	0%	17%	12%	24%	12%	16%	22%	15%
over 25 percent	15%	10%	19%	18%	12%	16%	15%	18%	18%	16%	21%	11%	12%	0%	10%	18%	13%	14%	16%	17%	15%
DON'T KNOW	26%	28%	21%	45%	32%	31%	21%	36%	38%	21%	27%	26%	32%	0%	33%	23%	24%	33%	24%	32%	22%
N	211	115	78	18	53	49	88	11	10	60	56	68	27	0	57	108	46	74	158	60	98

EC7.What is the approximate number of full-time equivalent workers of all types employed by your organization at this facility?	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
1 to 10	5%	7%	3%	5%	6%	8%	4%	0%	0%	0%	3%	7%	15%	0%	7%	3%	7%	4%	5%	7%	4%
11 to 50	22%	25%	20%	12%	14%	22%	25%	9%	18%	18%	19%	26%	25%	0%	26%	22%	16%	14%	23%	20%	25%
51 to 100	16%	12%	19%	20%	19%	12%	18%	0%	9%	13%	15%	16%	29%	0%	10%	18%	20%	15%	16%	10%	18%
100 to 250	21%	23%	18%	22%	25%	20%	17%	36%	36%	13%	23%	26%	20%	0%	13%	27%	14%	28%	20%	23%	18%
251 to 500	16%	14%	18%	15%	21%	12%	15%	27%	9%	17%	17%	18%	6%	0%	15%	20%	7%	20%	15%	15%	15%
501 to 1000	5%	4%	6%	0%	2%	6%	6%	9%	0%	10%	6%	1%	0%	0%	3%	6%	5%	3%	6%	7%	5%
Or, over 1000	14%	14%	13%	26%	15%	16%	12%	18%	29%	28%	15%	7%	0%	0%	20%	5%	31%	17%	14%	17%	13%
REFUSED	0%	0%	1%	0%	0%	2%	0%	0%	0%	0%	1%	0%	0%	0%	0%	1%	0%	0%	0%	2%	0%
DON'T KNOW	1%	1%	2%	0%	0%	0%	2%	0%	0%	0%	2%	0%	6%	0%	5%	0%	0%	0%	1%	0%	2%
N	211	115	78	18	53	49	88	11	10	60	56	68	27	0	57	108	46	74	158	60	98

EC9A. Which of the following is the LARGEST end use in terms of electricity consumption for this facility?	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
Lighting	9%	10%	7%	17%	13%	8%	7%	9%	9%	9%	12%	5%	12%	0%	11%	3%	20%	12%	8%	8%	7%
HVAC	31%	32%	30%	30%	33%	27%	28%	55%	47%	30%	30%	28%	41%	0%	43%	17%	50%	38%	30%	31%	30%
Continuous processing	36%	31%	42%	25%	29%	39%	41%	9%	27%	39%	37%	39%	24%	0%	17%	54%	14%	26%	38%	34%	40%
Batch processing	6%	5%	5%	7%	4%	8%	6%	0%	0%	4%	6%	9%	0%	0%	3%	8%	2%	3%	6%	7%	5%
Refrigeration	8%	11%	8%	0%	7%	10%	9%	9%	0%	3%	6%	13%	15%	0%	13%	8%	4%	7%	9%	10%	8%
Pumps	2%	2%	0%	17%	4%	2%	2%	0%	0%	3%	1%	3%	0%	0%	0%	1%	7%	3%	2%	2%	1%
Electric motors	2%	1%	3%	0%	2%	0%	3%	0%	0%	5%	1%	0%	0%	0%	0%	4%	0%	1%	2%	0%	3%
Machines	1%	3%	0%	0%	4%	2%	0%	0%	0%	1%	0%	0%	6%	0%	1%	1%	0%	3%	0%	2%	0%
Production equipment	1%	1%	0%	0%	0%	0%	0%	0%	18%	0%	1%	1%	0%	0%	0%	1%	0%	2%	1%	0%	1%
Blower	1%	2%	0%	0%	2%	0%	0%	9%	0%	0%	1%	0%	3%	0%	0%	1%	2%	3%	0%	2%	0%
Computers	1%	1%	0%	5%	2%	0%	1%	0%	0%	1%	2%	0%	0%	0%	3%	0%	0%	1%	1%	0%	1%
Motor homes	2%	0%	3%	0%	0%	0%	3%	0%	0%	0%	3%	3%	0%	0%	6%	0%	0%	0%	2%	0%	3%
Slot machines	0%	1%	0%	0%	0%	0%	0%	9%	0%	0%	0%	1%	0%	0%	1%	0%	0%	1%	0%	2%	0%
Testing equipment	1%	0%	2%	0%	0%	0%	1%	0%	0%	3%	0%	0%	0%	0%	0%	1%	0%	0%	1%	0%	1%
Air compressors	0%	1%	0%	0%	0%	2%	0%	0%	0%	1%	0%	0%	0%	0%	0%	1%	0%	0%	0%	2%	0%
DON'T KNOW	0%	1%	0%	0%	0%	2%	0%	0%	0%	1%	0%	0%	0%	0%	0%	0%	2%	0%	0%	2%	0%
N	211	115	78	18	53	49	88	11	10	60	56	68	27	0	57	108	46	74	158	60	98

EC9B. And which would you say used the SECOND most electricity?	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
Lighting	37%	33%	42%	20%	31%	31%	41%	18%	56%	34%	30%	41%	44%	0%	39%	32%	46%	32%	38%	29%	41%
HVAC	22%	23%	20%	32%	24%	29%	19%	27%	18%	22%	22%	19%	32%	0%	24%	20%	25%	24%	22%	28%	19%
Continuous processing	13%	16%	12%	7%	11%	14%	14%	18%	0%	9%	18%	12%	15%	0%	8%	19%	4%	11%	13%	15%	13%
Batch processing	11%	13%	9%	20%	15%	8%	11%	0%	18%	9%	15%	13%	6%	0%	6%	15%	7%	13%	10%	7%	12%
Refrigeration	2%	0%	3%	10%	6%	2%	1%	0%	0%	3%	0%	5%	0%	0%	3%	3%	0%	4%	1%	2%	1%
Pumps	1%	0%	2%	0%	0%	0%	1%	0%	0%	0%	0%	3%	0%	0%	0%	1%	0%	0%	1%	0%	1%
Computers	2%	3%	0%	7%	4%	0%	1%	9%	9%	2%	3%	1%	0%	0%	3%	2%	0%	5%	1%	2%	1%
Air compressors	0%	1%	0%	0%	0%	0%	1%	0%	0%	0%	0%	1%	0%	0%	0%	1%	0%	0%	1%	0%	1%
Medical equipment	2%	2%	3%	0%	2%	0%	3%	9%	0%	4%	3%	1%	0%	0%	0%	1%	9%	3%	2%	2%	3%
Telecommunications equipment	1%	2%	0%	0%	2%	2%	0%	0%	0%	0%	0%	1%	3%	0%	1%	0%	2%	1%	0%	2%	0%
Conveyors	1%	0%	2%	0%	0%	0%	1%	0%	0%	3%	0%	0%	0%	0%	3%	0%	0%	0%	1%	0%	1%
Cooking	0%	1%	0%	0%	2%	0%	0%	0%	0%	0%	1%	0%	0%	0%	0%	0%	2%	1%	0%	0%	0%
DC plant	0%	1%	0%	0%	0%	0%	1%	0%	0%	1%	0%	0%	0%	0%	0%	0%	2%	0%	1%	0%	1%
Plug loads	0%	1%	0%	0%	0%	0%	0%	9%	0%	1%	0%	0%	0%	0%	1%	0%	0%	1%	0%	2%	0%
OTHER - SPECIFY	1%	1%	1%	0%	0%	4%	0%	0%	0%	1%	1%	0%	0%	0%	1%	1%	0%	0%	1%	3%	0%
REFUSED	0%	1%	0%	0%	0%	2%	0%	0%	0%	1%	0%	0%	0%	0%	0%	0%	2%	0%	0%	2%	0%
DON'T KNOW	6%	4%	7%	5%	4%	8%	6%	9%	0%	9%	7%	4%	0%	0%	11%	5%	2%	4%	6%	8%	5%
N	211	115	78	18	53	49	88	11	10	60	56	68	27	0	57	108	46	74	158	60	98

EC10. Does this location have any on-site electricity generators?	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
Yes,for backup/standby purposes only	40%	50%	31%	50%	41%	43%	35%	82%	73%	52%	49%	33%	14%	0%	48%	35%	46%	51%	40%	49%	37%
Yes, everyday supplement / replacement f	5%	3%	4%	17%	9%	2%	4%	0%	9%	5%	1%	6%	6%	0%	1%	2%	14%	8%	3%	2%	4%
No	54%	45%	65%	33%	50%	51%	61%	18%	18%	41%	49%	61%	77%	0%	49%	63%	38%	41%	55%	46%	59%
REFUSED	0%	1%	0%	0%	0%	2%	0%	0%	0%	0%	0%	0%	3%	0%	1%	0%	0%	0%	0%	2%	0%
DON'T KNOW	0%	1%	0%	0%	0%	2%	0%	0%	0%	1%	0%	0%	0%	0%	0%	0%	2%	0%	0%	2%	0%
N	211	115	78	18	53	49	88	11	10	60	56	68	27	0	57	108	46	74	158	60	98

EC10a. What percent of this location's electricity load can be met by your on-site generation?	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
0	2%	2%	0%	8%	4%	0%	2%	0%	0%	0%	3%	3%	0%	0%	3%	0%	3%	2%	1%	0%	2%
1	15%	10%	22%	8%	4%	18%	22%	0%	0%	16%	12%	19%	0%	0%	22%	17%	3%	2%	18%	13%	20%
2	3%	3%	4%	0%	4%	0%	4%	0%	11%	7%	3%	0%	0%	0%	6%	3%	0%	4%	3%	0%	5%
3	2%	3%	0%	0%	4%	0%	2%	0%	0%	2%	0%	3%	0%	0%	0%	2%	3%	2%	1%	0%	2%
4	1%	0%	0%	8%	4%	0%	0%	0%	0%	2%	0%	0%	0%	0%	3%	0%	0%	2%	0%	0%	0%
5	3%	1%	4%	8%	4%	9%	0%	11%	0%	2%	5%	3%	0%	0%	0%	5%	3%	4%	3%	10%	0%
6	2%	0%	4%	0%	0%	0%	4%	0%	0%	0%	6%	0%	0%	0%	0%	4%	0%	0%	2%	0%	3%
10	12%	11%	13%	8%	11%	18%	11%	0%	11%	11%	11%	16%	0%	0%	6%	19%	6%	9%	12%	13%	11%
12	2%	3%	0%	0%	4%	0%	2%	0%	0%	2%	0%	3%	0%	0%	0%	4%	0%	2%	1%	0%	2%
15	1%	2%	0%	0%	4%	0%	0%	0%	0%	0%	3%	0%	0%	0%	3%	0%	0%	2%	0%	0%	0%
16	1%	2%	0%	0%	0%	5%	0%	0%	0%	2%	0%	0%	0%	0%	0%	2%	0%	0%	1%	3%	0%
18	1%	2%	0%	0%	4%	0%	0%	0%	0%	0%	0%	3%	0%	0%	0%	2%	0%	2%	0%	0%	0%
20	6%	5%	9%	0%	4%	0%	9%	0%	11%	5%	11%	0%	14%	0%	5%	4%	9%	4%	7%	0%	9%
25	4%	6%	2%	0%	0%	14%	2%	11%	0%	2%	8%	3%	0%	0%	3%	3%	6%	2%	5%	13%	2%
30	3%	0%	6%	0%	0%	5%	4%	0%	0%	2%	6%	0%	0%	0%	3%	0%	6%	0%	3%	3%	3%
40	2%	3%	0%	0%	7%	0%	0%	0%	0%	0%	3%	0%	14%	0%	3%	0%	3%	5%	0%	0%	0%
50	1%	3%	0%	0%	0%	5%	0%	0%	11%	0%	2%	3%	0%	0%	3%	0%	3%	2%	2%	3%	1%
60	2%	3%	0%	8%	4%	0%	0%	22%	0%	4%	3%	0%	0%	0%	5%	0%	3%	6%	2%	6%	0%
70	3%	2%	4%	0%	0%	0%	6%	0%	0%	7%	0%	0%	0%	0%	3%	4%	0%	0%	3%	0%	5%
80	5%	8%	2%	0%	4%	9%	4%	0%	11%	0%	9%	5%	14%	0%	3%	7%	3%	4%	5%	7%	5%
90	2%	3%	0%	0%	4%	0%	0%	0%	11%	4%	0%	0%	0%	0%	0%	2%	2%	4%	1%	0%	1%
100	22%	17%	24%	40%	26%	14%	22%	44%	11%	16%	10%	39%	44%	0%	19%	12%	42%	27%	21%	22%	21%
135	1%	2%	0%	0%	4%	0%	0%	0%	0%	0%	0%	0%	14%	0%	0%	0%	3%	2%	0%	0%	0%
650	1%	2%	0%	0%	0%	5%	0%	0%	0%	2%	0%	0%	0%	0%	3%	0%	0%	0%	1%	3%	0%
9999	7%	7%	4%	15%	4%	0%	7%	11%	24%	13%	6%	0%	0%	0%	6%	10%	3%	9%	7%	3%	9%
Mean	46.63	53.25	36.85	53.93	48.27	60.35	37.34	68.75	50.29	51.93	31.24	48.45	82.61	.	55.09	30.19	62.51	52.26	46.16	62.42	38.61
N	102	62	28	12	27	22	36	9	8	37	31	28	6	0	30	43	29	44	75	31	44

EC10b. Are their legal restrictions on the number of hours your on-site system can run during the summer?	ALL	PGE	SCE	SDGE	CPP only	DBP Bid only	DBP NonBid only	CPP & DBP Bid only	CPP & DBP NonBid	Extra Large	Large	Medium	Small	Very Small	COM	IND	INS	ALL CPP	ALL DBP	ALL DBP Bid	ALL DBP NonBid
Yes	67%	61%	76%	61%	67%	73%	65%	89%	43%	76%	80%	51%	14%	0%	53%	68%	79%	66%	67%	77%	62%
No	27%	31%	20%	39%	30%	23%	26%	11%	57%	20%	17%	39%	72%	0%	35%	26%	21%	31%	27%	20%	30%
DON'T KNOW	6%	9%	4%	0%	4%	5%	9%	0%	0%	4%	3%	10%	14%	0%	12%	6%	0%	2%	7%	3%	8%
N	102	62	28	12	27	22	36	9	8	37	31	28	6	0	30	43	29	44	75	31	44

C3. 2005 Traditional Interruptible Customer Survey Results

PROGRAM SATISFACTION

PS1. How long have you been participating in the [PROGRAM] program?	Total	PG&E	SCE	SDG&E	Extra Large	Large	Medium	Small	Com-mercial	Industrial	Insti-tutional
1 year	2%	0%	2%	0%	3%	0%	5%	0%	0%	3%	0%
3 years	5%	0%	6%	0%	0%	10%	5%	0%	0%	4%	12%
4 years	5%	6%	5%	0%	6%	5%	5%	0%	9%	6%	0%
5 years	7%	0%	7%	100%	3%	10%	5%	14%	9%	7%	6%
6 years	7%	0%	9%	0%	0%	5%	20%	14%	0%	8%	6%
7 years	3%	12%	1%	0%	3%	0%	10%	0%	0%	3%	6%
8 years	6%	6%	6%	0%	6%	7%	0%	14%	27%	4%	0%
10 years	18%	12%	20%	0%	19%	17%	15%	29%	27%	18%	12%
More than 10 years	40%	59%	37%	0%	45%	44%	30%	29%	18%	39%	59%
DON'T KNOW	6%	6%	6%	0%	13%	2%	5%	0%	9%	7%	0%
N	99	17	81	1	31	41	20	7	11	71	17

PS2. What was the primary reason for signing up for the [PROGRAM] program?	Total	PG&E	SCE	SDG&E	Extra Large	Large	Medium	Small	Com-mercial	Industrial	Insti-tutional
Save Money on energy costs/bills	95%	88%	98%	0%	94%	98%	95%	86%	100%	93%	100%
Being able to participate without significantly affecting busin	1%	6%	0%	0%	0%	0%	5%	0%	0%	1%	0%
Being a good corporate citizen	1%	0%	1%	0%	0%	2%	0%	0%	0%	1%	0%
We inherited it	2%	6%	1%	0%	6%	0%	0%	0%	0%	3%	0%
Record verbatim	1%	0%	0%	100%	0%	0%	0%	14%	0%	1%	0%
N	99	17	81	1	31	41	20	7	11	71	17

PS3a. Rate your satisfaction with...The enrollment process and determination of your firm service level	Total	PG&E	SCE	SDG&E	Extra Large	Large	Medium	Small	Com-mercial	Industrial	Insti-tutional
Very Satisfied	57%	71%	54%	0%	65%	56%	45%	57%	73%	56%	47%
Somewhat satisfied	28%	18%	31%	0%	23%	37%	25%	14%	9%	28%	41%
Somewhat dissatisfied	1%	0%	1%	0%	3%	0%	0%	0%	0%	1%	0%
Very dissatified	1%	0%	1%	0%	3%	0%	0%	0%	0%	1%	0%
DON'T KNOW	13%	12%	12%	100%	6%	7%	30%	29%	18%	13%	12%
Mean	1.38	1.20	1.42	.	1.41	1.39	1.36	1.20	1.11	1.40	1.47
N	99	17	81	1	31	41	20	7	11	71	17

PS3b. Rate your satisfaction with...The notification process for interruption events/critical price periods	Total	PG&E	SCE	SDG&E	Extra Large	Large	Medium	Small	Com-mercial	Industrial	Insti-tutional
Very Satisfied	60%	47%	63%	0%	71%	61%	50%	29%	91%	58%	47%
Somewhat satisfied	32%	47%	30%	0%	19%	34%	40%	57%	9%	31%	53%
Somewhat dissatisfied	6%	6%	6%	0%	10%	5%	5%	0%	0%	8%	0%
DON'T KNOW	2%	0%	1%	100%	0%	0%	5%	14%	0%	3%	0%
Mean	1.45	1.59	1.43	.	1.39	1.44	1.53	1.67	1.09	1.49	1.53
N	99	17	81	1	31	41	20	7	11	71	17

PS3c. Rate your satisfaction with...The frequency of interruption events/critical price periods	Total	PG&E	SCE	SDG&E	Extra Large	Large	Medium	Small	Com-mercial	Industrial	Insti-tutional
Very Satisfied	54%	76%	49%	0%	61%	44%	55%	71%	73%	54%	41%
Somewhat satisfied	35%	18%	40%	0%	29%	46%	35%	0%	27%	32%	53%
Somewhat dissatisfied	7%	6%	7%	0%	6%	7%	5%	14%	0%	8%	6%
Very dissatified	2%	0%	2%	0%	3%	2%	0%	0%	0%	3%	0%
DON'T KNOW	2%	0%	1%	100%	0%	0%	5%	14%	0%	3%	0%
Mean	1.57	1.29	1.63	.	1.52	1.68	1.47	1.33	1.27	1.59	1.65
N	99	17	81	1	31	41	20	7	11	71	17

PS3d. Rate your satisfaction with...The duration of nterruption events/critical price periods	Total	PG&E	SCE	SDG&E	Extra Large	Large	Medium	Small	Com-mercial	Industrial	Insti-tutional
Very Satisfied	49%	71%	46%	0%	55%	44%	45%	71%	64%	46%	53%
Somewhat satisfied	41%	29%	44%	0%	39%	49%	45%	0%	36%	42%	41%
Somewhat dissatisfied	5%	0%	6%	0%	3%	5%	5%	14%	0%	6%	6%
Very dissatified	2%	0%	2%	0%	3%	2%	0%	0%	0%	3%	0%
DON'T KNOW	2%	0%	1%	100%	0%	0%	5%	14%	0%	3%	0%
Mean	1.59	1.29	1.65	.	1.55	1.66	1.58	1.33	1.36	1.64	1.53
N	99	17	81	1	31	41	20	7	11	71	17

PS3e. Rate your satisfaction with...The reduced overall energy and demand charges for participation	Total	PG&E	SCE	SDG&E	Extra Large	Large	Medium	Small	Com-mercial	Industrial	Insti-tutional
Very Satisfied	53%	65%	51%	0%	55%	56%	40%	57%	82%	45%	65%
Somewhat satisfied	35%	29%	37%	0%	32%	34%	50%	14%	18%	38%	35%
Somewhat dissatisfied	5%	0%	6%	0%	6%	2%	5%	14%	0%	7%	0%
Very dissatified	2%	6%	1%	0%	3%	2%	0%	0%	0%	3%	0%
DON'T KNOW	5%	0%	5%	100%	3%	5%	5%	14%	0%	7%	0%
Mean	1.54	1.47	1.56	.	1.57	1.49	1.63	1.50	1.18	1.65	1.35
N	99	17	81	1	31	41	20	7	11	71	17

PS3f. Rate your satisfaction with...The level of penalties for failure to curtail during interruption events/critical peak prices	Total	PG&E	SCE	SDG&E	Extra Large	Large	Medium	Small	Com-mercial	Industrial	Insti-tutional
Very Satisfied	35%	53%	32%	0%	42%	37%	25%	29%	55%	28%	53%
Somewhat satisfied	24%	35%	22%	0%	32%	17%	30%	14%	27%	24%	24%
Somewhat dissatisfied	19%	6%	22%	0%	16%	20%	20%	29%	9%	21%	18%
Very dissatified	11%	6%	12%	0%	6%	15%	10%	14%	0%	14%	6%
DON'T KNOW	10%	0%	11%	100%	3%	12%	15%	14%	9%	13%	0%
Mean	2.07	1.65	2.17	.	1.87	2.14	2.18	2.33	1.50	2.24	1.76
N	99	17	81	1	31	41	20	7	11	71	17

PS3g. Rate your satisfaction with...The [SOFTWARE] load management software available from your utility	Total	PG&E	SCE	SDG&E	Extra Large	Large	Medium	Small	Com-mercial	Industrial	Insti-tutional
Very Satisfied	31%	35%	31%	0%	45%	27%	25%	14%	45%	30%	29%
Somewhat satisfied	33%	24%	36%	0%	23%	39%	40%	29%	36%	31%	41%
Somewhat dissatisfied	3%	0%	4%	0%	3%	2%	0%	14%	0%	4%	0%
Very dissatified	1%	0%	1%	0%	0%	0%	5%	0%	0%	1%	0%
REFUSED	1%	0%	1%	0%	0%	0%	5%	0%	0%	1%	0%
DON'T KNOW	30%	41%	27%	100%	29%	32%	25%	43%	18%	32%	29%
Mean	1.62	1.40	1.66	.	1.41	1.64	1.79	2.00	1.44	1.66	1.58
N	99	17	81	1	31	41	20	7	11	71	17

PS4. Overall, how satisfied are you with your participation in this program?	Total	PG&E	SCE	SDG&E	Extra Large	Large	Medium	Small	Com-mercial	Industrial	Insti-tutional
Very Satisfied	67%	82%	63%	100%	81%	63%	50%	71%	100%	63%	59%
Somewhat satisfied	31%	18%	35%	0%	16%	37%	45%	29%	0%	34%	41%
Somewhat dissatisfied	1%	0%	1%	0%	3%	0%	0%	0%	0%	1%	0%
DON'T KNOW	1%	0%	1%	0%	0%	0%	5%	0%	0%	1%	0%
Mean	1.34	1.18	1.38	1.00	1.23	1.37	1.47	1.29	1.00	1.37	1.41
N	99	17	81	1	31	41	20	7	11	71	17

PS4a. Could you briefly summarize why your experience with the [PROGRAM] program has been unsatisfactory?	Total	PG&E	SCE	SDG&E	Extra Large	Large	Medium	Small	Com-mercial	Industrial	Insti-tutional
RECORD VERBATIM....PROBE FOR OTHER REASO	100%	.	100%	.	100%	.	.	.	.	100%	.
REFUSED	0%	.	0%	.	0%	.	.	.	.	0%	.
DON'T KNOW	0%	.	0%	.	0%	.	.	.	.	0%	.
N	1	0	1	0	1	0	0	0	0	1	0

PS5. Have you re-designated your firm service level since you originally enrolled in this program?	Total	PG&E	SCE	SDG&E	Extra Large	Large	Medium	Small	Com-mercial	Industrial	Insti-tutional
Yes	39%	29%	41%	0%	39%	44%	25%	50%	27%	44%	24%
No	54%	59%	53%	0%	55%	51%	60%	50%	64%	49%	71%
DON'T KNOW	7%	12%	6%	0%	6%	5%	15%	0%	9%	7%	6%
N	98	17	81	0	31	41	20	6	11	70	17

PS5a. Approximately what year did you do this?	Total	PG&E	SCE	SDG&E	Extra Large	Large	Medium	Small	Com-mercial	Industrial	Insti-tutional
2005	8%	0%	9%	0%	0%	6%	40%	0%	0%	6%	25%
2004	11%	0%	12%	0%	17%	6%	0%	33%	0%	10%	25%
2003	21%	60%	15%	0%	33%	11%	20%	33%	33%	23%	0%
2002	24%	0%	27%	0%	17%	33%	20%	0%	33%	23%	25%
2001	13%	20%	12%	0%	17%	17%	0%	0%	0%	16%	0%
2000	11%	20%	9%	0%	8%	11%	20%	0%	33%	6%	25%
1999	5%	0%	6%	0%	8%	6%	0%	0%	0%	6%	0%
1995	3%	0%	3%	0%	0%	6%	0%	0%	0%	3%	0%
Over 10 years ago	3%	0%	3%	0%	0%	0%	0%	33%	0%	3%	0%
DON'T KNOW	3%	0%	3%	0%	0%	6%	0%	0%	0%	3%	0%
N	38	5	33	0	12	18	5	3	3	31	4

PS5b. Did you increase or decrease your firm service level?	Total	PG&E	SCE	SDG&E	Extra Large	Large	Medium	Small	Com-mercial	Industrial	Insti-tutional
Increase	76%	80%	76%	0%	83%	72%	100%	33%	67%	81%	50%
Decrease	16%	0%	18%	0%	8%	22%	0%	33%	0%	13%	50%
DON'T KNOW	8%	20%	6%	0%	8%	6%	0%	33%	33%	6%	0%
N	38	5	33	0	12	18	5	3	3	31	4

PS5c. Could you briefly summarize why you re-designated your firm service level?	Total	PG&E	SCE	SDG&E	Extra Large	Large	Medium	Small	Com-mercial	Industrial	Insti-tutional
Previous curtailment commitments were too much	18%	20%	18%	.	8%	22%	20%	33%	0%	23%	0%
Required by contract because summer peak demand fell	0%	0%	0%	.	0%	0%	0%	0%	0%	0%	0%
Wanted to keep some of facility operational	24%	0%	27%	.	25%	33%	0%	0%	0%	29%	0%
Acquired a generator	8%	0%	9%	.	0%	11%	0%	33%	33%	6%	0%
Expanded facility/Added equipment	16%	20%	15%	.	8%	22%	20%	0%	0%	19%	0%
Needed level to be higher for proper shut down	8%	20%	6%	.	17%	0%	0%	33%	0%	10%	0%
Penalities	5%	20%	3%	.	0%	6%	0%	33%	0%	6%	0%
Always change (year to year)	5%	0%	6%	.	8%	6%	0%	0%	0%	0%	50%
RECORD VERBATIM	18%	0%	21%	.	25%	6%	60%	0%	33%	13%	50%
REFUSED	0%	0%	0%	.	0%	0%	0%	0%	0%	0%	0%
DON'T KNOW	3%	20%	0%	.	8%	0%	0%	0%	33%	0%	0%
N	38	5	33	0	12	18	5	3	3	31	4

2005 EVENT EXPERIENCE

EX1. How often was your organization called upon to curtai in 2005, not including test events [or did you experience critical peak prices in 2005]?	Total	PG&E	SCE	SDG&E	Extra Large	Large	Medium	Small	Com-mercial	Industrial	Insti-tutional
0	20%	65%	10%	100%	26%	10%	30%	29%	9%	17%	41%
1	30%	18%	33%	0%	29%	37%	20%	29%	36%	32%	18%
2	21%	12%	23%	0%	19%	24%	20%	14%	18%	23%	18%
3	14%	0%	17%	0%	16%	10%	15%	29%	9%	17%	6%
4	3%	6%	2%	0%	3%	5%	0%	0%	18%	1%	0%
6	3%	0%	4%	0%	0%	5%	5%	0%	0%	3%	6%
12	1%	0%	1%	0%	3%	0%	0%	0%	9%	0%	0%
Don't know	7%	0%	9%	0%	3%	10%	10%	0%	0%	7%	12%
Mean	1.70	0.65	1.96	0.00	1.73	1.81	1.50	1.43	2.82	1.62	1.20
N	99	17	81	1	31	41	20	7	11	71	17

EX2. Does your organization have a pre-established curtailment strategy?	Total	PG&E	SCE	SDG&E	Extra Large	Large	Medium	Small	Com-mercial	Industrial	Insti-tutional
Yes	85%	88%	85%	0%	87%	80%	90%	86%	82%	85%	88%
No	14%	12%	14%	100%	10%	20%	10%	14%	9%	15%	12%
DON'T KNOW	1%	0%	1%	0%	3%	0%	0%	0%	9%	0%	0%
N	99	17	81	1	31	41	20	7	11	71	17

EX3. What specific actions do you take to reduce load during curtailment event(s)?	Total	PG&E	SCE	SDG&E	Extra Large	Large	Medium	Small	Com-mercial	Industrial	Insti-tutional
Turn off/reduce overhead lighting	26%	0%	32%	0%	13%	37%	30%	14%	9%	31%	18%
Turn off computers and other office equipment	16%	0%	20%	0%	13%	20%	20%	0%	0%	20%	12%
Reduce thermostat temperature setting	24%	0%	30%	0%	16%	32%	30%	0%	9%	31%	6%
Shut down some or all production processes	66%	53%	69%	0%	68%	61%	75%	57%	36%	80%	24%
Shift production to other day or period	23%	6%	26%	100%	19%	17%	25%	71%	18%	27%	12%
Shut down some or all refrigeration/cold storage	10%	6%	11%	0%	3%	17%	5%	14%	9%	11%	6%
Run back-up generators	38%	53%	36%	0%	42%	41%	25%	43%	55%	27%	76%
Other actions - SPECIFY	1%	0%	1%	0%	0%	2%	0%	0%	0%	1%	0%
REFUSED	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
DON'T KNOW	3%	0%	4%	0%	6%	2%	0%	0%	9%	3%	0%
N	99	17	81	1	31	41	20	7	11	71	17

EX3A_1. Cost of of Turning off and red... per hour or per event?	Total	PG&E	SCE	SDG&E	Extra Large	Large	Medium	Small	Com-mercial	Industrial	Insti-tutional
Given per hour	19%	0%	19%	0%	25%	27%	0%	0%	100%	18%	0%
Given per event	15%	0%	15%	0%	25%	7%	33%	0%	0%	18%	0%
DON'T KNOW	65%	0%	65%	0%	50%	67%	67%	100%	0%	64%	100%
N	26	0	26	0	4	15	6	1	1	22	3

EX3B_1. Cost of of Turning off and red... per hour	Total	PG&E	SCE	SDG&E	Extra Large	Large	Medium	Small	Com-mercial	Industrial	Insti-tutional
0	60%	0%	60%	0%	100%	50%	0%	0%	0%	75%	0%
400	20%	0%	20%	0%	0%	25%	0%	0%	100%	0%	0%
5000	20%	0%	20%	0%	0%	25%	0%	0%	0%	25%	0%
Mean	1080	.	1080	.	0	1350	.	.	400	1250	.
N	5	0	5	0	1	4	0	0	1	4	0

EX3C_1. Cost of of Turning off and red... per event	Total	PG&E	SCE	SDG&E	Extra Large	Large	Medium	Small	Com-mercial	Industrial	Insti-tutional
0	50%	0%	50%	0%	100%	0%	50%	0%	0%	50%	0%
2000	25%	0%	25%	0%	0%	0%	50%	0%	0%	25%	0%
5000	25%	0%	25%	0%	0%	100%	0%	0%	0%	25%	0%
Mean	1750	.	1750	.	0	5000	1000	.	.	1750	.
N	4	0	4	0	1	1	2	0	0	4	0

EX3A_2. Cost of of Turning off computer... per hour or per event?	Total	PG&E	SCE	SDG&E	Extra Large	Large	Medium	Small	Com-mercial	Industrial	Insti-tutional
Given per hour	6%	0%	6%	0%	25%	0%	0%	0%	0%	7%	0%
Given per event	19%	0%	19%	0%	25%	13%	25%	0%	0%	21%	0%
DON'T KNOW	75%	0%	75%	0%	50%	88%	75%	0%	0%	71%	100%
N	16	0	16	0	4	8	4	0	0	14	2

EX3B_2. Cost of of Turning off computer… per hour	Total	PG&E	SCE	SDG&E	Extra Large	Large	Medium	Small	Com-mercial	Industrial	Insti-tutional
0	100%	0%	100%	0%	100%	0%	0%	0%	0%	100%	0%
Mean	0	.	0	.	0	.	.	.	.	0	.
N	1	0	1	0	1	0	0	0	0	1	0

EX3C_2. Cost of of Turning off computer… per event	Total	PG&E	SCE	SDG&E	Extra Large	Large	Medium	Small	Com-mercial	Industrial	Insti-tutional
0	67%	0%	67%	0%	100%	0%	100%	0%	0%	67%	0%
5000	33%	0%	33%	0%	0%	100%	0%	0%	0%	33%	0%
Mean	1667	.	1667	.	0	5000	0	.	.	1667	.
N	3	0	3	0	1	1	1	0	0	3	0

EX3A_3. Cost of Reducing thermostat... per hour or per event?	Total	PG&E	SCE	SDG&E	Extra Large	Large	Medium	Small	Com-mercial	Industrial	Insti-tutional
Given per hour	8%	0%	8%	0%	20%	7%	0%	0%	0%	9%	0%
Given per event	12%	0%	12%	0%	0%	14%	17%	0%	0%	13%	0%
Other	4%	0%	4%	0%	0%	7%	0%	0%	0%	4%	0%
DON'T KNOW	76%	0%	76%	0%	80%	71%	83%	0%	100%	74%	100%
N	25	0	25	0	5	14	6	0	1	23	1

EX3B_3. Cost of of Reducing thermostat… per hour	Total	PG&E	SCE	SDG&E	Extra Large	Large	Medium	Small	Com-mercial	Industrial	Insti-tutional
0	100%	0%	100%	0%	100%	100%	0%	0%	0%	100%	0%
Mean	0	.	0	.	0	0	.	.	.	0	.
N	2	0	2	0	1	1	0	0	0	2	0

EX3C_3. Cost of of Reducing thermostat… per event	Total	PG&E	SCE	SDG&E	Extra Large	Large	Medium	Small	Com-mercial	Industrial	Insti-tutional
0	67%	0%	67%	0%	0%	50%	100%	0%	0%	67%	0%
1000	33%	0%	33%	0%	0%	50%	0%	0%	0%	33%	0%
Mean	333	.	333	.	.	500	0	.	.	333	.
N	3	0	3	0	0	2	1	0	0	3	0

EX3A_4. Cost of of Shutting down some... per hour or per event?	Total	PG&E	SCE	SDG&E	Extra Large	Large	Medium	Small	Com-mercial	Industrial	Insti-tutional
Given per hour	34%	22%	36%	0%	38%	25%	31%	75%	25%	33%	67%
Given per event	19%	22%	19%	0%	14%	21%	31%	0%	0%	22%	0%
Other	2%	0%	2%	0%	0%	4%	0%	0%	0%	2%	0%
REFUSED	5%	11%	4%	0%	5%	4%	8%	0%	25%	4%	0%
DON'T KNOW	40%	44%	40%	0%	43%	46%	31%	25%	50%	40%	33%
N	62	9	53	0	21	24	13	4	4	55	3

EX3B_4. Cost of of Shutting down some… per hour	Total	PG&E	SCE	SDG&E	Extra Large	Large	Medium	Small	Com-mercial	Industrial	Insti-tutional
400	5%	0%	5%	0%	0%	17%	0%	0%	0%	6%	0%
500	5%	0%	5%	0%	0%	17%	0%	0%	0%	0%	50%
1000	10%	0%	11%	0%	0%	0%	0%	67%	0%	11%	0%
2000	19%	50%	16%	0%	25%	17%	25%	0%	100%	17%	0%
3000	5%	0%	5%	0%	0%	0%	25%	0%	0%	6%	0%
4000	5%	0%	5%	0%	0%	17%	0%	0%	0%	6%	0%
5000	33%	50%	32%	0%	38%	17%	50%	33%	0%	33%	50%
20000	5%	0%	5%	0%	13%	0%	0%	0%	0%	6%	0%
100000	14%	0%	16%	0%	25%	17%	0%	0%	0%	17%	0%
Mean	17757	3500	19258	.	29875	18650	3750	2333	2000	20300	2750
N	21	2	19	0	8	6	4	3	1	18	2

EX3C_4. Cost of of Shutting down some… per event	Total	PG&E	SCE	SDG&E	Extra Large	Large	Medium	Small	Com-mercial	Industrial	Insti-tutional
500	8%	0%	10%	0%	0%	20%	0%	0%	0%	8%	0%
2000	17%	0%	20%	0%	0%	20%	25%	0%	0%	17%	0%
4000	17%	50%	10%	0%	0%	0%	50%	0%	0%	17%	0%
5000	8%	0%	10%	0%	0%	0%	25%	0%	0%	8%	0%
10000	17%	0%	20%	0%	33%	20%	0%	0%	0%	17%	0%
25000	8%	0%	10%	0%	33%	0%	0%	0%	0%	8%	0%
30000	8%	0%	10%	0%	0%	20%	0%	0%	0%	8%	0%
60000	8%	50%	0%	0%	0%	20%	0%	0%	0%	8%	0%
100000	8%	0%	10%	0%	33%	0%	0%	0%	0%	8%	0%
Mean	21042	32000	18850	.	45000	20500	3750	.	.	21042	.
N	12	2	10	0	3	5	4	0	0	12	0

EX3A_5. Shift production to other day or time pe … per hour or per event?	Total	PG&E	SCE	SDG&E	Extra Large	Large	Medium	Small	Com-mercial	Industrial	Insti-tutional
Given per hour	35%	0%	38%	0%	50%	0%	40%	60%	0%	37%	50%
Given per event	4%	0%	5%	0%	0%	0%	0%	20%	0%	5%	0%
REFUSED	9%	0%	10%	0%	17%	14%	0%	0%	50%	5%	0%
DON'T KNOW	52%	100%	48%	100%	33%	86%	60%	20%	50%	53%	50%
N	23%	1%	21%	1%	6%	7%	5%	5%	2%	19%	2%

EX3B_5. Shift production to other day or time pe … per hour	Total	PG&E	SCE	SDG&E	Extra Large	Large	Medium	Small	Com-mercial	Industrial	Insti-tutional
0	13%	0%	13%	0%	0%	0%	0%	33%	0%	14%	0%
350	13%	0%	13%	0%	0%	0%	50%	0%	0%	14%	0%
500	13%	0%	13%	0%	0%	0%	0%	33%	0%	14%	0%
1000	25%	0%	25%	0%	33%	0%	50%	0%	0%	14%	100%
1200	13%	0%	13%	0%	33%	0%	0%	0%	0%	14%	0%
5000	13%	0%	13%	0%	0%	0%	0%	33%	0%	14%	0%
25000	13%	0%	13%	0%	33%	0%	0%	0%	0%	14%	0%
Mean	4256	.	4256	.	9067	.	675	1833	.	4721	1000
N	8	0	8	0	3	0	2	3	0	7	1

EX3C_5. Shift production to other day or time pe … per event	Total	PG&E	SCE	SDG&E	Extra Large	Large	Medium	Small	Com-mercial	Industrial	Insti-tutional
5000	100%	0%	100%	0%	0%	0%	0%	100%	0%	100%	0%
Mean	5000	.	5000	.	.	.	.	5000	.	5000	.
N	1	0	1	0	0	0	0	1	0	1	0

EX3A_6. Shut down some or all refrigeration/cold … per hour or per event?	Total	PG&E	SCE	SDG&E	Extra Large	Large	Medium	Small	Com-mercial	Industrial	Insti-tutional
Given per hour	10%	0%	11%	0%	0%	14%	0%	0%	0%	13%	0%
Given per event	40%	0%	44%	0%	100%	14%	100%	100%	0%	50%	0%
REFUSED	10%	100%	0%	0%	0%	14%	0%	0%	100%	0%	0%
DON'T KNOW	40%	0%	44%	0%	0%	57%	0%	0%	0%	38%	100%
N	10	1	9	0	1	7	1	1	1	8	1

EX3B_6. Shut down some or all refrigeration/cold … per hour	Total	PG&E	SCE	SDG&E	Extra Large	Large	Medium	Small	Com-mercial	Industrial	Insti-tutional
200	100%	0%	100%	0%	0%	100%	0%	0%	0%	100%	0%
Mean	200	.	200	.	.	200	.	.	.	200	.
N	1	0	1	0	0	1	0	0	0	1	0

EX3C_6. Shut down some or all refrigeration/cold … per event	Total	PG&E	SCE	SDG&E	Extra Large	Large	Medium	Small	Com-mercial	Industrial	Insti-tutional
0	25%	0%	25%	0%	0%	0%	100%	0%	0%	25%	0%
500	25%	0%	25%	0%	0%	100%	0%	0%	0%	25%	0%
4000	25%	0%	25%	0%	100%	0%	0%	0%	0%	25%	0%
5000	25%	0%	25%	0%	0%	0%	0%	100%	0%	25%	0%
Mean	2375	.	2375	.	4000	500	0	5000	.	2375	.
N	4	0	4	0	1	1	1	1	0	4	0

EX3A_7. Run back-up generators … per hour or per event?	Total	PG&E	SCE	SDG&E	Extra Large	Large	Medium	Small	Com-mercial	Industrial	Insti-tutional
Given per hour	35%	44%	32%	0%	46%	31%	20%	33%	17%	44%	31%
Given per event	16%	11%	18%	0%	0%	31%	0%	33%	17%	22%	8%
77	5%	0%	7%	0%	0%	13%	0%	0%	0%	0%	15%
DON'T KNOW	43%	44%	43%	0%	54%	25%	80%	33%	67%	33%	46%
N	37	9	28	0	13	16	5	3	6	18	13

EX3B_7. Run back-up generators … per hour	Total	PG&E	SCE	SDG&E	Extra Large	Large	Medium	Small	Com-mercial	Industrial	Insti-tutional
0	8%	0%	11%	0%	20%	0%	0%	0%	0%	13%	0%
65	8%	33%	0%	0%	20%	0%	0%	0%	0%	0%	33%
70	8%	0%	11%	0%	0%	20%	0%	0%	0%	13%	0%
120	8%	0%	11%	0%	0%	20%	0%	0%	0%	13%	0%
200	8%	0%	11%	0%	20%	0%	0%	0%	100%	0%	0%
500	8%	0%	11%	0%	20%	0%	0%	0%	0%	13%	0%
550	8%	33%	0%	0%	0%	20%	0%	0%	0%	0%	33%
600	8%	33%	0%	0%	0%	0%	100%	0%	0%	13%	0%
1000	8%	0%	11%	0%	0%	20%	0%	0%	0%	13%	0%
2000	8%	0%	11%	0%	20%	0%	0%	0%	0%	0%	33%
3000	8%	0%	11%	0%	0%	20%	0%	0%	0%	13%	0%
5000	8%	0%	11%	0%	0%	0%	0%	100%	0%	13%	0%
Mean	1092	405	1321	.	553	948	600	5000	200	1286	872
N	12	3	9	0	5	5	1	1	1	8	3

EX3C_7. Run back-up generators … per event	Total	PG&E	SCE	SDG&E	Extra Large	Large	Medium	Small	Com-mercial	Industrial	Insti-tutional
0	17%	0%	20%	0%	0%	20%	0%	0%	100%	0%	0%
600	17%	100%	0%	0%	0%	20%	0%	0%	0%	0%	100%
2000	17%	0%	20%	0%	0%	20%	0%	0%	0%	25%	0%
3000	17%	0%	20%	0%	0%	20%	0%	0%	0%	25%	0%
6000	17%	0%	20%	0%	0%	20%	0%	0%	0%	25%	0%
12000	17%	0%	20%	0%	0%	0%	0%	100%	0%	25%	0%
Mean	3933	600	4600	.	.	2320	.	12000	0	5750	600
N	6	1	5	0	0	5	0	1	1	4	1

EX3A_77. Other… per hour or per event?	Total	PG&E	SCE	SDG&E	Extra Large	Large	Medium	Small	Com-mercial	Industrial	Insti-tutional
Given per event	100%	0%	100%	0%	0%	100%	0%	0%	0%	100%	0%
N	1	0	1	0	0	1	0	0	0	1	0

EX3B_77. Other… per hour	Total	PG&E	SCE	SDG&E	Extra Large	Large	Medium	Small	Com-mercial	Industrial	Insti-tutional
N	.	.	.	.	.	.	.	.	.	.	.

EX3C_77. Other… per event	Total	PG&E	SCE	SDG&E	Extra Large	Large	Medium	Small	Com-mercial	Industrial	Insti-tutional
5000	100%	0%	100%	0%	0%	100%	0%	0%	0%	100%	0%
Mean	5000	.	5000	.	.	5000	.	.	.	5000	.
N	1	0	1	0	0	1	0	0	0	1	0

EX4. To what extent are these load reductions centrally controlled, as opposed to being a diffuse set of manual actions?	Total	PG&E	SCE	SDG&E	Extra Large	Large	Medium	Small	Com-mercial	Industrial	Insti-tutional
Entirely centrally controlled	39%	53%	36%	100%	52%	27%	35%	71%	55%	37%	41%
Partially centrally controlled	23%	12%	26%	0%	23%	27%	25%	0%	0%	24%	35%
Not at all centrally controlled	37%	35%	38%	0%	26%	46%	40%	29%	45%	39%	24%
N	99	17	81	1	31	41	20	7	11	71	17

EX5. Have you used the [SOFTWARE] software available from [UTILITY] to help plan or manage your load reductions?	Total	PG&E	SCE	SDG&E	Extra Large	Large	Medium	Small	Com-mercial	Industrial	Insti-tutional
Yes	22%	29%	21%	0%	26%	20%	15%	43%	36%	23%	12%
No	75%	71%	77%	0%	71%	78%	85%	43%	64%	73%	88%
DON'T KNOW	3%	0%	2%	100%	3%	2%	0%	14%	0%	4%	0%
N	99	17	81	1	31	41	20	7	11	71	17

EX5a. How useful has the [SOFTWARE] software provided by [UTILITY] been in managing or planning your load reductions?	Total	PG&E	SCE	SDG&E	Extra Large	Large	Medium	Small	Com-mercial	Industrial	Insti-tutional
Very helpful	32%	20%	35%	0%	13%	50%	33%	33%	25%	38%	0%
Somewhat helpful	55%	80%	47%	0%	63%	50%	67%	33%	50%	50%	100%
Not at all helpful	9%	0%	12%	0%	13%	0%	0%	33%	0%	13%	0%
DON'T KNOW	5%	0%	6%	0%	13%	0%	0%	0%	25%	0%	0%
N	22	5	17	0	8	8	3	3	4	16	2

EX5b. What aspects of the [SOFTWARE] software have been the most useful in managing or planning your load reductions?	Total	PG&E	SCE	SDG&E	Extra Large	Large	Medium	Small	Com-mercial	Industrial	Insti-tutional
Monitor our usage	32%	20%	36%	.	33%	38%	33%	0%	33%	36%	0%
Monitor system load	26%	40%	21%	.	50%	0%	33%	50%	33%	29%	0%
Nothing	10%	20%	7%	.	14%	13%	0%	0%	0%	7%	50%
RECORD VERBATIM	10%	0%	13%	.	0%	25%	0%	0%	33%	0%	50%
REFUSED	0%	0%	0%	.	0%	0%	0%	0%	0%	0%	0%
DON'T KNOW	26%	20%	29%	.	17%	25%	33%	50%	0%	36%	0%
N	19	5	14	0	6	8	3	2	3	14	2

EX6. Would you say that it is generally easy or difficult for your organization to curtail the amount of load required in the required timeframe?	Total	PG&E	SCE	SDG&E	Extra Large	Large	Medium	Small	Com-mercial	Industrial	Insti-tutional
Very easy	25%	18%	26%	100%	19%	29%	20%	43%	27%	23%	35%
Somewhat easy	41%	41%	42%	0%	42%	39%	50%	29%	45%	41%	41%
Somewhat difficult	27%	41%	25%	0%	32%	24%	25%	29%	27%	28%	24%
Very difficult	6%	0%	7%	0%	6%	7%	5%	0%	0%	8%	0%
N	99	17	81	1	31	41	20	7	11	71	17

EX6a. Briefly, what is the main reason why your organization has found it [ANSWER TO EX6] to curtail in the required timeframe?	Total	PG&E	SCE	SDG&E	Extra Large	Large	Medium	Small	Com-mercial	Industrial	Insti-tutional
We have established a plan	20%	18%	21%	0%	16%	24%	20%	14%	0%	23%	24%
Not enough time to curtail after notification	10%	18%	9%	0%	19%	7%	5%	0%	27%	8%	6%
We switch to our generator	11%	12%	11%	0%	10%	7%	15%	29%	18%	7%	24%
Automated controls	8%	0%	10%	0%	10%	10%	5%	0%	18%	4%	18%
Manual shut down	6%	6%	6%	0%	6%	5%	10%	0%	0%	7%	6%
Plenty of time to reduce load	4%	12%	2%	0%	3%	7%	0%	0%	9%	3%	6%
Easy to shut down	6%	0%	7%	0%	0%	10%	10%	0%	9%	6%	6%
Difficult to shut down	11%	12%	11%	0%	19%	7%	5%	14%	9%	14%	0%
Costly/Production losses	10%	12%	10%	0%	10%	10%	10%	14%	0%	14%	0%
RECORD VERBATIM	13%	18%	11%	100%	10%	10%	20%	29%	9%	13%	18%
REFUSED	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
DON'T KNOW	1%	0%	1%	0%	0%	2%	0%	0%	0%	1%	0%
N	99	17	81	1	31	41	20	7	11	71	17

NOTIFICATON TECHNOLOGY

NM1. What type of event notification systems does this facility use for the [PROGRAM] program?	Total	PG&E	SCE	SDG&E	Extra Large	Large	Medium	Small	Com-mercial	Industrial	Insti-tutional
Remote Terminal Unit (RTU)	63%	24%	72%	0%	45%	78%	55%	71%	64%	65%	53%
Two-Way Paging	5%	6%	5%	0%	6%	5%	0%	14%	9%	6%	0%
Email or Interactive Website	24%	47%	19%	100%	19%	29%	25%	14%	55%	18%	29%
Fax	22%	94%	7%	0%	29%	20%	25%	0%	36%	17%	35%
Telephone/Cellphone	48%	53%	48%	0%	35%	49%	75%	29%	64%	46%	47%
Alarm	12%	12%	12%	0%	16%	12%	10%	0%	0%	17%	0%
Other - RECORD	2%	0%	2%	0%	0%	0%	5%	14%	0%	3%	0%
REFUSED	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
DON'T KNOW	1%	0%	1%	0%	3%	0%	0%	0%	0%	1%	0%
N	99	17	81	1	31	41	20	7	11	71	17

AUTOMATION TECHNOLOGY

AT1. Does this facility have an Energy Management and Control System (EMCS) for centrally controlling some or all of the heating, ventilation, and air conditioning system or other equipment?	Total	PG&E	SCE	SDG&E	Extra Large	Large	Medium	Small	Com-mercial	Industrial	Insti-tutional
Yes	38%	47%	36%	100%	42%	41%	30%	29%	55%	27%	76%
No	60%	53%	62%	0%	55%	56%	70%	71%	45%	70%	24%
DON'T KNOW	2%	0%	2%	0%	3%	2%	0%	0%	0%	3%	0%
N	99	17	81	1	31	41	20	7	11	71	17

AT1a. And which of the following systems does your EMCS control?	Total	PG&E	SCE	SDG&E	Extra Large	Large	Medium	Small	Com-mercial	Industrial	Insti-tutional
Rooftop or other distributed HVAC units	68%	50%	72%	100%	62%	71%	83%	50%	67%	58%	85%
Central Cooling Plant	47%	75%	41%	0%	46%	53%	50%	0%	67%	21%	77%
Major Ventilation fans	55%	75%	52%	0%	54%	65%	50%	0%	67%	32%	85%
Zone Temperature	42%	63%	38%	0%	31%	59%	33%	0%	50%	26%	62%
Lighting equipment	32%	25%	34%	0%	23%	29%	50%	50%	50%	37%	15%
Production process	39%	38%	41%	0%	46%	41%	17%	50%	50%	47%	23%
Other systems - SPECIFY	5%	25%	0%	0%	0%	12%	0%	0%	17%	0%	8%
REFUSED	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
DON'T KNOW	5%	0%	7%	0%	8%	0%	17%	0%	17%	5%	0%
N	38	8	29	1	13	17	6	2	6	19	13

AT1b. Does your EMCS offer the ability to control all of the space temperatures on an individual zone basis, that is, can it turn up or down each of the temperature set points individually?	Total	PG&E	SCE	SDG&E	Extra Large	Large	Medium	Small	Com-mercial	Industrial	Insti-tutional
Yes	62%	50%	63%	100%	71%	54%	60%	100%	40%	55%	80%
No	38%	50%	37%	0%	29%	46%	40%	0%	60%	45%	20%
N	26	6	19	1	7	13	5	1	5	11	10

AT1c. Does your EMCS offer the ability to control all of the space temperatures on a "global" basis, that is, can it turn up or down all of the space temperature set points using a simple screen or other centralized action?	Total	PG&E	SCE	SDG&E	Extra Large	Large	Medium	Small	Com-mercial	Industrial	Insti-tutional
Yes	35%	67%	21%	100%	71%	23%	0%	100%	40%	18%	50%
No	58%	33%	68%	0%	14%	69%	100%	0%	60%	82%	30%
DON'T KNOW	8%	0%	11%	0%	14%	8%	0%	0%	0%	0%	20%
N	26	6	19	1	7	13	5	1	5	11	10

AT2. What type of HVAC equipment controls the temperature of the occupied space(s) at your facility?	Total	PG&E	SCE	SDG&E	Extra Large	Large	Medium	Small	Com-mercial	Industrial	Insti-tutional
VAV boxes	12%	18%	11%	0%	10%	15%	15%	0%	45%	3%	29%
Constant volume mixing boxes or	9%	12%	9%	0%	16%	7%	5%	0%	0%	8%	18%
Both (VAV and constant volume)	4%	0%	5%	0%	6%	5%	0%	0%	9%	0%	18%
Thermostat	37%	18%	41%	100%	29%	34%	45%	71%	27%	45%	12%
No HVAC	8%	12%	7%	0%	6%	7%	15%	0%	0%	11%	0%
Something else...SPECIFY	4%	18%	1%	0%	3%	7%	0%	0%	0%	3%	12%
REFUSED	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
DON'T KNOW	28%	35%	27%	0%	32%	29%	20%	29%	18%	30%	29%
N	99	17	81	1	31	41	20	7	11	71	17

AT2a. Is your facility's space temperature control system primarily pneumatic, direct digital control, or some of both?	Total	PG&E	SCE	SDG&E	Extra Large	Large	Medium	Small	Com-mercial	Industrial	Insti-tutional
Pneumatic	3%	0%	4%	0%	3%	2%	5%	0%	18%	0%	6%
Direct digital controls	33%	41%	31%	100%	29%	41%	25%	29%	36%	32%	35%
Some of both	34%	35%	35%	0%	35%	34%	35%	29%	36%	30%	53%
No HVAC/Control system	12%	12%	12%	0%	10%	7%	25%	14%	0%	17%	0%
Thermostat	3%	6%	2%	0%	3%	2%	5%	0%	9%	3%	0%
RECORD OTHER	1%	0%	1%	0%	3%	0%	0%	0%	0%	1%	0%
DON'T KNOW	13%	6%	15%	0%	16%	12%	5%	29%	0%	17%	6%
N	99	17	81	1	31	41	20	7	11	71	17

AUTOMATION INVESTMENTS

EA8. In the past 2 years, has your organization considered any automation investments in order to improve your ability to manage energy use at this facility?	Total	PG&E	SCE	SDG&E	Extra Large	Large	Medium	Small	Com-mercial	Industrial	Insti-tutional
Yes	44%	76%	38%	0%	58%	39%	35%	43%	55%	38%	65%
No	55%	24%	60%	100%	39%	61%	65%	57%	45%	61%	35%
DON'T KNOW	1%	0%	1%	0%	3%	0%	0%	0%	0%	1%	0%
N	99	17	81	1	31	41	20	7	11	71	17

EA9. What are the reasons why your organization considered these upgrades to your control systems?	Total	PG&E	SCE	SDG&E	Extra Large	Large	Medium	Small	Com-mercial	Industrial	Insti-tutional
Save on energy costs	86%	92%	84%	.	83%	88%	100%	67%	83%	89%	82%
Upgrade old equipment	27%	15%	32%	.	22%	38%	14%	33%	17%	22%	45%
Increase flexibility of controls systems	7%	15%	3%	.	11%	6%	0%	0%	17%	7%	0%
Be able to respond to dynamic pricing	2%	8%	0%	.	6%	0%	0%	0%	17%	0%	0%
To increase occupant comfort	0%	0%	0%	.	0%	0%	0%	0%	0%	0%	0%
Increase production	5%	8%	3%	.	11%	0%	0%	0%	17%	4%	0%
Other reason - RECORD	0%	0%	0%	.	0%	0%	0%	0%	0%	0%	0%
REFUSED	0%	0%	0%	.	0%	0%	0%	0%	0%	0%	0%
DON'T KNOW	0%	0%	0%	.	0%	0%	0%	0%	0%	0%	0%
N	44	13	31	0	18	16	7	3	6	27	11

EA10. Did you actually install any of these control system upgrades for your business?	Total	PG&E	SCE	SDG&E	Extra Large	Large	Medium	Small	Com-mercial	Industrial	Insti-tutional
Yes	57%	54%	58%	0%	72%	56%	43%	0%	67%	52%	64%
No	39%	38%	39%	0%	17%	44%	57%	100%	33%	44%	27%
DON'T KNOW	5%	8%	3%	0%	11%	0%	0%	0%	0%	4%	9%
N	44	13	31	0	18	16	7	3	6	27	11

EA11. And which upgrades did you choose to install?	Total	PG&E	SCE	SDG&E	Extra Large	Large	Medium	Small	Com-mercial	Industrial	Insti-tutional
Controls or EMCS	48%	57%	44%	.	54%	33%	67%	.	50%	43%	57%
Variable frequency drives	36%	43%	33%	.	38%	44%	0%	.	50%	36%	29%
Programmable thermostat	28%	43%	22%	.	23%	33%	33%	.	25%	29%	29%
Sensors or motion detectors	24%	43%	17%	.	31%	11%	33%	.	25%	21%	29%
Lighting	12%	14%	11%	.	8%	22%	0%	.	0%	21%	0%
Motors	8%	14%	6%	.	0%	22%	0%	.	0%	14%	0%
Blower	4%	14%	0%	.	8%	0%	0%	.	0%	0%	14%
Co-generator	4%	14%	0%	.	8%	0%	0%	.	0%	0%	14%
Chiller	4%	0%	6%	.	0%	0%	33%	.	0%	7%	0%
Water pumps	4%	0%	6%	.	8%	0%	0%	.	25%	0%	0%
Other upgrades -Specify	8%	0%	11%	.	0%	22%	0%	.	0%	7%	14%
REFUSED	0%	0%	0%	.	0%	0%	0%	.	0%	0%	0%
DON'T KNOW	8%	0%	11%	.	15%	0%	0%	.	25%	0%	14%
N	25	7	18	0	13	9	3	0	4	14	7

DR PROGRAM AWARENESS & FAMILIARITY

F2a. How familiar is your organization with [UTILITY'S] voluntary Critical Peak Pricing (CPP) tariff?	Total	PG&E	SCE	SDG&E	Extra Large	Large	Medium	Small	Com-mercial	Industrial	Insti-tutional
Very Familiar	18%	12%	19%	100%	13%	24%	15%	14%	27%	15%	24%
Somewhat familiar	54%	41%	57%	0%	65%	49%	45%	57%	64%	52%	53%
Not at all familiar	28%	47%	25%	0%	23%	27%	40%	29%	9%	32%	24%
N	99	17	81	1	31	41	20	7	11	71	17

F2b. How familiar is your organization with [UTILITY'S] Demand Bidding Program (DBP)?	Total	PG&E	SCE	SDG&E	Extra Large	Large	Medium	Small	Com-mercial	Industrial	Insti-tutional
Very Familiar	17%	0%	21%	0%	19%	22%	10%	0%	27%	17%	12%
Somewhat familiar	40%	53%	38%	0%	39%	37%	55%	29%	45%	41%	35%
Not at all familiar	41%	47%	40%	100%	39%	41%	35%	71%	27%	41%	53%
DON'T KNOW	1%	0%	1%	0%	3%	0%	0%	0%	0%	1%	0%
N	99	17	81	1	31	41	20	7	11	71	17

F2c. How familiar is your organization with the California Demand Reserves Partnership (Cal-DRP) program?	Total	PG&E	SCE	SDG&E	Extra Large	Large	Medium	Small	Com-mercial	Industrial	Insti-tutional
Very Familiar	6%	0%	7%	0%	6%	7%	5%	0%	9%	6%	6%
Somewhat familiar	21%	18%	22%	0%	23%	22%	20%	14%	45%	20%	12%
Not at all familiar	73%	82%	70%	100%	71%	71%	75%	86%	45%	75%	82%
N	99	17	81	1	31	41	20	7	11	71	17

F2d. How familiar is your organization with [UTILITY'S] Base Interruptible Program (BIP)?	Total	PG&E	SCE	SDG&E	Extra Large	Large	Medium	Small	Com-mercial	Industrial	Insti-tutional
Very Familiar	19%	18%	20%	0%	23%	15%	30%	0%	9%	21%	18%
Somewhat familiar	44%	35%	47%	0%	52%	44%	35%	43%	55%	41%	53%
Not at all familiar	35%	47%	32%	100%	23%	41%	35%	57%	36%	37%	29%
DON'T KNOW	1%	0%	1%	0%	3%	0%	0%	0%	0%	1%	0%
N	99	17	81	1	31	41	20	7	11	71	17

OUTLOOK GOING FORWARD

GF1. Do you anticipate remaining in the [PROGRAM] program next summer?	Total	PG&E	SCE	SDG&E	Extra Large	Large	Medium	Small	Com-mercial	Industrial	Insti-tutional
Yes	98%	100%	98%	100%	100%	95%	100%	100%	100%	99%	94%
No	2%	0%	2%	0%	0%	5%	0%	0%	0%	1%	6%
N	99	17	81	1	31	41	20	7	11	71	17

GF1a. What other rate or program would you be most likely to consider?	Total	PG&E	SCE	SDG&E	Extra Large	Large	Medium	Small	Com-mercial	Industrial	Insti-tutional
Critical Peak Pricing (CPP)	0%	.	0%	.	.	0%	.	.	.	0%	0%
Demand Bidding (DBP)	0%	.	0%	.	.	0%	.	.	.	0%	0%
Base Interruptible Program (BIP)	0%	.	0%	.	.	0%	.	.	.	0%	0%
Optional Binding Mandatory Curtailment (OBMC)	0%	.	0%	.	.	0%	.	.	.	0%	0%
SCHEDULED LOAD REDUCTION PROGRAM (SLRP)	0%	.	0%	.	.	0%	.	.	.	0%	0%
Rolling Blackout Reduction Program (RBRP	0%	.	0%	.	.	0%	.	.	.	0%	0%
Other Program - SPECIFY	1%	.	1%	.	.	1%	.	.	.	0%	1%
REFUSED	0%	.	0%	.	.	0%	.	.	.	0%	0%
DON'T KNOW	1%	.	1%	.	.	1%	.	.	.	1%	0%
N	2	0	2	0	0	2	0	0	0	1	1

GF1b. Which features of [PROGRAMS CITED IN GF1a] are most attractive to your organization?	Total	PG&E	SCE	SDG&E	Extra Large	Large	Medium	Small	Com-mercial	Industrial	Insti-tutional
Pricing/incentives	0%	.	0%	.	.	0%	.	.	.	.	0%
Penalty levels or structure	0%	.	0%	.	.	0%	.	.	.	.	0%
Event notification	0%	.	0%	.	.	0%	.	.	.	.	0%
Event frequency	0%	.	0%	.	.	0%	.	.	.	.	0%
Event duration	0%	.	0%	.	.	0%	.	.	.	.	0%
Length of settlement process	0%	.	0%	.	.	0%	.	.	.	.	0%
Reliability of supply	0%	.	0%	.	.	0%	.	.	.	.	0%
OTHER - SPECIFY	1%	.	1%	.	.	1%	.	.	.	.	1%
REFUSED	0%	.	0%	.	.	0%	.	.	.	.	0%
DON'T KNOW	0%	.	0%	.	.	0%	.	.	.	.	0%
N	1	0	1	0	0	1	0	0	0	0	1

GF2. In the last two years, have you considered switching to another rate or participating in demand response programs?	Total	PG&E	SCE	SDG&E	Extra Large	Large	Medium	Small	Com-mercial	Industrial	Insti-tutional
Yes	26%	29%	25%	0%	29%	23%	20%	43%	18%	27%	25%
No	72%	71%	72%	100%	71%	74%	75%	57%	82%	71%	69%
DON'T KNOW	2%	0%	3%	0%	0%	3%	5%	0%	0%	1%	6%
N	97	17	79	1	31	39	20	7	11	70	16

GF2a. If yes, which programs appealed to you?	Total	PG&E	SCE	SDG&E	Extra Large	Large	Medium	Small	Com-mercial	Industrial	Insti-tutional
Critical Peak Pricing (CPP)	12%	0%	15%	.	22%	0%	25%	0%	0%	11%	25%
Demand Bidding (DBP)	32%	20%	35%	.	22%	44%	25%	33%	50%	32%	25%
Base Interruptible Program (BIP)	8%	0%	10%	.	11%	0%	0%	33%	0%	5%	25%
Optional Binding Mandatory Curtailment (OBMC)	0%	0%	0%	.	0%	0%	0%	0%	0%	0%	0%
SCHEDULED LOAD REDUCTION PROGRAM (SLRP)	8%	20%	5%	.	11%	11%	0%	0%	0%	5%	25%
Rolling Blackout Reduction Program (RBRP	0%	0%	0%	.	0%	0%	0%	0%	0%	0%	0%
None	8%	20%	5%	.	11%	11%	0%	0%	0%	11%	0%
Time of Use	12%	0%	15%	.	0%	11%	25%	33%	0%	16%	0%
Non Firm	4%	20%	0%	.	0%	0%	25%	0%	0%	5%	0%
Direct Access	4%	0%	5%	.	11%	0%	0%	0%	0%	5%	0%
Other Program - SPECIFY	0%	0%	0%	.	0%	0%	0%	0%	0%	0%	0%
REFUSED	0%	0%	0%	.	0%	0%	0%	0%	0%	0%	0%
DON'T KNOW	20%	20%	20%	.	22%	22%	25%	0%	50%	16%	25%
N	25	5	20	0	9	9	4	3	2	19	4

GF2b. Which features of this program are most attractive to your organization?	Total	PG&E	SCE	SDG&E	Extra Large	Large	Medium	Small	Com-mercial	Industrial	Insti-tutional
Pricing/incentives	60%	60%	60%	.	67%	56%	50%	67%	50%	58%	75%
Penalty levels or structure	8%	0%	10%	.	0%	11%	25%	0%	0%	11%	0%
Event notification	8%	0%	10%	.	22%	0%	0%	0%	0%	11%	0%
Event frequency	0%	0%	0%	.	0%	0%	0%	0%	0%	0%	0%
Event duration	0%	0%	0%	.	0%	0%	0%	0%	0%	0%	0%
Length of settlement process	0%	0%	0%	.	0%	0%	0%	0%	0%	0%	0%
Reliability of supply	4%	0%	5%	.	0%	0%	0%	33%	0%	5%	0%
Program complexity	0%	0%	0%	.	0%	0%	0%	0%	0%	0%	0%
Nothing	8%	0%	10%	.	0%	22%	0%	0%	0%	5%	25%
OTHER - SPECIFY	8%	20%	5%	.	0%	11%	25%	0%	0%	11%	0%
REFUSED	0%	0%	0%	.	0%	0%	0%	0%	0%	0%	0%
DON'T KNOW	12%	20%	10%	.	22%	0%	25%	0%	50%	11%	0%
N	25	5	20	0	9	9	4	3	2	19	4

GF2c. Which features did you not like about the programs you considered?	Total	PG&E	SCE	SDG&E	Extra Large	Large	Medium	Small	Com-mercial	Industrial	Insti-tutional
Pricing/incentives	36%	40%	35%	.	22%	33%	50%	67%	0%	42%	25%
Penalty levels or structure	4%	0%	5%	.	0%	0%	0%	33%	0%	5%	0%
Event notification	4%	0%	5%	.	11%	0%	0%	0%	0%	0%	25%
Event frequency	8%	20%	5%	.	0%	22%	0%	0%	50%	0%	25%
Event duration	8%	0%	10%	.	11%	0%	0%	33%	0%	11%	0%
Length of settlement process	0%	0%	0%	.	0%	0%	0%	0%	0%	0%	0%
Reliability of supply	4%	0%	5%	.	11%	0%	0%	0%	0%	5%	0%
Program complexity	4%	0%	5%	.	0%	0%	25%	0%	0%	5%	0%
Nothing	8%	0%	10%	.	0%	22%	0%	0%	0%	11%	0%
OTHER - SPECIFY	8%	20%	5%	.	22%	0%	0%	0%	0%	5%	25%
REFUSED	0%	0%	0%	.	0%	0%	0%	0%	0%	0%	0%
DON'T KNOW	24%	20%	25%	.	33%	22%	25%	0%	50%	26%	0%
N	25	5	20	0	9	9	4	3	2	19	4

GF3. Are you aware of the Technical Assistance Incentive Program to help customers identify demand response load reduction opportunities within their facility and help offset the costs of implementing those opportunities?	Total	PG&E	SCE	SDG&E	Extra Large	Large	Medium	Small	Com-mercial	Industrial	Insti-tutional
Yes	67%	76%	64%	100%	77%	63%	55%	71%	73%	63%	76%
No	31%	24%	33%	0%	23%	34%	40%	29%	27%	34%	24%
DON'T KNOW	2%	0%	2%	0%	0%	2%	5%	0%	0%	3%	0%
N	99	17	81	1	31	41	20	7	11	71	17

GF3a. Are you planning to enroll in the Technical Assistance Incentive Program?	Total	PG&E	SCE	SDG&E	Extra Large	Large	Medium	Small	Com-mercial	Industrial	Insti-tutional
Yes	21%	23%	21%	0%	21%	15%	45%	0%	13%	20%	31%
No	64%	69%	62%	100%	67%	62%	45%	100%	63%	64%	62%
Already enrolled	6%	8%	6%	0%	0%	15%	0%	0%	25%	4%	0%
DON'T KNOW	9%	0%	12%	0%	13%	8%	9%	0%	0%	11%	8%
N	66	13	52	1	24	26	11	5	8	45	13

GF3b. Which aspects of the Technical Assistance Incentive Program are you planning to use?	Total	PG&E	SCE	SDG&E	Extra Large	Large	Medium	Small	Com-mercial	Industrial	Insti-tutional
Preliminary audit	21%	33%	18%	.	20%	0%	40%	.	0%	22%	25%
Detailed technical audit	36%	67%	27%	.	40%	25%	40%	.	100%	33%	25%
Financial incentives to install demand response measures	36%	33%	36%	.	40%	25%	40%	.	0%	44%	25%
Other aspects - SPECIFY	0%	0%	0%	.	0%	0%	0%	.	0%	0%	0%
REFUSED	0%	0%	0%	.	0%	0%	0%	.	0%	0%	0%
DON'T KNOW	14%	0%	18%	.	0%	50%	0%	.	0%	11%	25%
N	14	3	11	0	5	4	5	0	1	9	4

GF4. Under the terms of service for [PROGRAM] customers, [IF UTILITY = PG&E or SCE: "service interruptions"; ELSE IF SDG&E: "critical price periods"] are limited to a maximum of [RULES]. In a worst-case scenario where the maximum number of [IF UTILITY = PG&E or SCE: "interruptions"; ELSE IF SDG&E: "critical price periods"] was required to avoid system emergencies, how likely is it that your organization would remain in the [PROGRAM] program?	Total	PG&E	SCE	SDG&E	Extra Large	Large	Medium	Small	Com-mercial	Industrial	Insti-tutional
Very likely	51%	65%	47%	100%	61%	37%	60%	57%	64%	49%	47%
Somewhat likely	17%	24%	16%	0%	16%	29%	0%	0%	36%	11%	29%
Somewhat unlikely	11%	0%	14%	0%	6%	15%	15%	0%	0%	14%	6%
Very unlikely	17%	6%	20%	0%	13%	15%	20%	43%	0%	21%	12%
DON'T KNOW	4%	6%	4%	0%	3%	5%	5%	0%	0%	4%	6%
N	99%	17%	81%	1%	31%	41%	20%	7%	11%	71%	17%

GF4a. What is the upper limit on the number of service interruptions/critical price periods that your organization could withstand in a worst-case scenario before considering leaving the [PROGRAM] program?	Total	PG&E	SCE	SDG&E	Extra Large	Large	Medium	Small	Com-mercial	Industrial	Insti-tutional
4 Events	4%	0%	4%	.	17%	0%	0%	0%	.	4%	0%
5 Events	7%	0%	7%	.	0%	0%	14%	33%	.	8%	0%
6 Events	11%	0%	11%	.	0%	25%	0%	0%	.	12%	0%
8 Events	7%	0%	7%	.	0%	8%	14%	0%	.	8%	0%
10 Events	21%	0%	22%	.	50%	8%	29%	0%	.	24%	0%
12 Events	4%	0%	4%	.	0%	8%	0%	0%	.	4%	0%
15 Events	7%	0%	7%	.	17%	0%	14%	0%	.	8%	0%
20 Events	7%	0%	7%	.	0%	17%	0%	0%	.	4%	33%
None	4%	0%	4%	.	0%	8%	0%	0%	.	4%	0%
Other	21%	100%	19%	.	17%	25%	0%	67%	.	16%	67%
DON'T KNOW	7%	0%	7%	.	0%	0%	29%	0%	.	8%	0%
Mean	9.5	.	9.5	.	9.8	9.8	9.6	5.0	.	8.9	20.0
N	28	1	27	0	6	12	7	3	0	25	3

GF4b. If these upper limits actually occurred, which of the following actions are you most likely to take?	Total	PG&E	SCE	SDG&E	Extra Large	Large	Medium	Small	Com-mercial	Industrial	Insti-tutional	
Go to a firm service rate	32%	0%	33%	0%	33%	36%	20%	33%	0%	32%	33%	
Go to a firm service rate and consider participating in demand response programs	32%	100%	29%	0%	33%	45%	20%	0%	0%	27%	67%	
Go to another non-firm service rate and consider participating in demand response programs	4%	0%	4%	0%	0%	0%	20%	0%	0%	5%	0%	
Discontinue service	12%	0%	13%	0%	17%	0%	20%	33%	0%	14%	0%	0.1
DON'T KNOW	20%	0%	21%	0%	17%	18%	20%	33%	0%	23%	0%	
N	25	1	24	0	6	11	5	3	0	22	3	

GF5. If the [PROGRAM] program were discontinued, which of the following actions would are you most likely to take?	Total	PG&E	SCE	SDG&E	Extra Large	Large	Medium	Small	Com-mercial	Industrial	Insti-tutional
Go to a firm service rate	17%	6%	19%	100%	13%	22%	10%	29%	27%	15%	18%
Go to a firm service rate and consider participating in demand response programs	20%	12%	22%	0%	13%	24%	20%	29%	0%	18%	41%
Go to another non-firm service rate	5%	12%	4%	0%	6%	2%	10%	0%	0%	7%	0%
Go to another non-firm service rate and consider participating in demand response programs	20%	35%	17%	0%	35%	5%	30%	14%	27%	18%	24%
Discontinue service	9%	6%	10%	0%	6%	10%	10%	14%	9%	11%	0%
Something else	1%	0%	1%	0%	0%	2%	0%	0%	0%	1%	0%
DON'T KNOW	27%	29%	27%	0%	26%	34%	20%	14%	36%	28%	18%
N	99	17	81	1	31	41	20	7	11	71	17

FIRMOGRAPHIC CHARACTERISTICS

EC1. What is the main activity performed at this location?	Total	PG&E	SCE	SDG&E	Extra Large	Large	Medium	Small	Com-mercial	Industrial	Insti-tutional
Office	3%	0%	4%	0%	6%	2%	0%	0%	18%	0%	6%
College/university	2%	0%	2%	0%	3%	2%	0%	0%	0%	0%	12%
School	1%	6%	0%	0%	0%	2%	0%	0%	0%	0%	6%
Health care/hospital	4%	12%	2%	0%	6%	2%	5%	0%	0%	0%	24%
Warehouse	9%	0%	11%	0%	0%	15%	15%	0%	18%	8%	6%
Personal Service	1%	0%	1%	0%	3%	0%	0%	0%	9%	0%	0%
Community Service/Church/Temple/Municipa	1%	0%	1%	0%	0%	0%	5%	0%	0%	0%	6%
Industrial Electronic & Machinery	5%	0%	6%	0%	6%	5%	5%	0%	9%	6%	0%
Industrial Mining. Metals. Stone. Glass.	9%	6%	10%	0%	10%	7%	15%	0%	9%	11%	0%
Industrial Petroleum. Plastic. Rubber an	10%	0%	12%	0%	13%	10%	5%	14%	0%	13%	6%
Other Industrial	13%	12%	12%	100%	16%	7%	5%	57%	9%	17%	0%
Agricultural	1%	0%	1%	0%	0%	2%	0%	0%	0%	1%	0%
Transportation/Telecommunications/Utilit	6%	18%	4%	0%	6%	10%	0%	0%	0%	0%	35%
Manufacturing	24%	12%	27%	0%	16%	22%	40%	29%	0%	34%	0%
Food processing	5%	12%	4%	0%	6%	7%	0%	0%	9%	6%	0%
Other SPECIFY	4%	18%	1%	0%	3%	5%	5%	0%	18%	3%	0%
REFUSED	1%	6%	0%	0%	3%	0%	0%	0%	0%	1%	0%
N	99	17	81	1	31	41	20	7	11	71	17

EC2. Approximately how many square feet does your organization occupy in this facility?	Total	PG&E	SCE	SDG&E	Extra Large	Large	Medium	Small	Com-mercial	Industrial	Insti-tutional
Less than 10,000 square feet	6%	6%	6%	0%	10%	5%	5%	0%	0%	4%	18%
10,000 but less than 20,000 square feet	2%	6%	1%	0%	3%	0%	0%	14%	0%	3%	0%
20,000 but less than 50,000 square feet	10%	12%	10%	0%	3%	12%	15%	14%	9%	11%	6%
50,000 but less than 100,000 square feet	17%	24%	16%	0%	19%	15%	15%	29%	27%	18%	6%
100,000 but less than 200,000 square fee	26%	6%	30%	100%	6%	32%	50%	14%	9%	31%	18%
200,000 but less than 300,000 square fee	11%	6%	12%	0%	6%	20%	0%	14%	9%	13%	6%
400,000 but less than 500,000 square fee	1%	6%	0%	0%	3%	0%	0%	0%	0%	0%	6%
Over 500,000 square feet	13%	12%	14%	0%	29%	10%	0%	0%	27%	7%	29%
Ag/Nonfacility - Outdoors	9%	12%	9%	0%	13%	2%	15%	14%	18%	10%	0%
REFUSED	1%	6%	0%	0%	3%	0%	0%	0%	0%	1%	0%
DON'T KNOW	3%	6%	2%	0%	3%	5%	0%	0%	0%	1%	12%
N	99	17	81	1	31	41	20	7	11	71	17

EC3. Does your organization own or lease?	Total	PG&E	SCE	SDG&E	Extra Large	Large	Medium	Small	Com-mercial	Industrial	Insti-tutional
Own this space	71%	82%	68%	100%	68%	68%	75%	86%	45%	68%	100%
Lease this space	22%	6%	26%	0%	19%	24%	25%	14%	45%	24%	0%
Own a portion and lease the remainder	6%	6%	6%	0%	10%	7%	0%	0%	9%	7%	0%
REFUSED	1%	6%	0%	0%	3%	0%	0%	0%	0%	1%	0%
N	99	17	81	1	31	41	20	7	11	71	17

EC5. What percent of your organization's total annual operating costs do energy costs represent?	Total	PG&E	SCE	SDG&E	Extra Large	Large	Medium	Small	Com-mercial	Industrial	Insti-tutional
Less than 1 percent	2%	0%	2%	0%	0%	2%	5%	0%	0%	3%	0%
1 to 4 percent	14%	6%	16%	0%	3%	15%	30%	14%	0%	18%	6%
5 to 10 percent	26%	18%	28%	0%	32%	20%	30%	29%	27%	25%	29%
11 TO 25 percent	16%	35%	12%	0%	23%	12%	5%	43%	18%	14%	24%
over 25 percent	17%	12%	19%	0%	26%	20%	5%	0%	18%	15%	24%
REFUSED	3%	6%	2%	0%	3%	2%	5%	0%	0%	3%	6%
DON'T KNOW	21%	24%	20%	100%	13%	29%	20%	14%	36%	21%	12%
N	99	17	81	1	31	41	20	7	11	71	17

EC5A. Has your organization assigned responsibility for controlling energy usage and costs to any of the following?	Total	PG&E	SCE	SDG&E	Extra Large	Large	Medium	Small	Com-mercial	Industrial	Insti-tutional
An in-house staff person	43%	41%	44%	0%	42%	44%	50%	29%	27%	49%	29%
A group of staff	38%	29%	41%	0%	32%	51%	25%	29%	64%	31%	53%
An outside contractor or	2%	0%	2%	0%	6%	0%	0%	0%	9%	1%	0%
to No one	15%	24%	12%	100%	16%	5%	25%	43%	0%	17%	18%
REFUSED	1%	6%	0%	0%	3%	0%	0%	0%	0%	1%	0%
N	99	17	81	1	31	41	20	7	11	71	17

EC6. Approximately how many locations does your organization have in California?	Total	PG&E	SCE	SDG&E	Extra Large	Large	Medium	Small	Com-mercial	Industrial	Insti-tutional
1	51%	47%	51%	100%	39%	44%	75%	71%	27%	58%	35%
2 to 4	22%	24%	22%	0%	23%	29%	10%	14%	9%	27%	12%
5 to 10	7%	6%	7%	0%	6%	10%	5%	0%	36%	4%	0%
11 to 25	8%	6%	9%	0%	10%	7%	5%	14%	0%	7%	18%
Over 25	11%	12%	11%	0%	19%	10%	5%	0%	27%	3%	35%
REFUSED	1%	6%	0%	0%	3%	0%	0%	0%	0%	1%	0%
N	99	17	81	1	31	41	20	7	11	71	17

EC7. What is the approximate number of full-time equivalen workers of all types employed by your organization at this facility?	Total	PG&E	SCE	SDG&E	Extra Large	Large	Medium	Small	Com-mercial	Industrial	Insti-tutional
1 to 10	4%	0%	5%	0%	0%	2%	10%	14%	0%	3%	12%
11 to 50	16%	12%	17%	0%	16%	12%	20%	29%	9%	15%	24%
51 to 100	16%	35%	12%	0%	16%	17%	15%	14%	27%	15%	12%
100 to 250	32%	24%	33%	100%	26%	34%	35%	43%	36%	39%	0%
251 to 500	15%	12%	16%	0%	13%	22%	10%	0%	18%	15%	12%
501 to 1000	9%	0%	11%	0%	13%	10%	5%	0%	9%	8%	12%
Or, over 1000	4%	12%	2%	0%	13%	0%	0%	0%	0%	0%	24%
REFUSED	3%	6%	2%	0%	3%	2%	5%	0%	0%	3%	6%
N	99	17	81	1	31	41	20	7	11	71	17

EC9A. Which of the following is the LARGEST end use in terms of electricity consumption for this facility?	Total	PG&E	SCE	SDG&E	Extra Large	Large	Medium	Small	Com-mercial	Industrial	Insti-tutional
Lighting	6%	6%	6%	0%	10%	7%	0%	0%	9%	3%	18%
HVAC	12%	18%	11%	0%	10%	10%	25%	0%	18%	6%	35%
Continuous processing	59%	59%	58%	100%	68%	56%	50%	57%	45%	69%	24%
Batch processing	9%	0%	11%	0%	0%	10%	15%	29%	0%	13%	0%
Refrigeration	6%	12%	5%	0%	6%	10%	0%	0%	27%	4%	0%
Motors/pumps	5%	0%	6%	0%	3%	5%	5%	14%	0%	3%	18%
OTHER - SPECIFY	1%	0%	1%	0%	0%	2%	0%	0%	0%	0%	6%
REFUSED	2%	6%	1%	0%	3%	0%	5%	0%	0%	3%	0%
N	99	17	81	1	31	41	20	7	11	71	17

EC9B. And which would you say used the SECOND most electricity?	Total	PG&E	SCE	SDG&E	Extra Large	Large	Medium	Small	Com-mercial	Industrial	Insti-tutional
Lighting	28%	29%	28%	0%	29%	29%	30%	14%	27%	28%	29%
HVAC	17%	12%	17%	100%	23%	15%	10%	29%	18%	11%	41%
Continuous processing	12%	12%	12%	0%	10%	12%	15%	14%	18%	13%	6%
Batch processing	20%	18%	21%	0%	10%	29%	15%	29%	9%	24%	12%
Refrigeration	8%	18%	6%	0%	10%	7%	10%	0%	9%	8%	6%
Motors/pumps	4%	6%	4%	0%	10%	0%	5%	0%	9%	4%	0%
OTHER - SPECIFY	5%	0%	6%	0%	6%	5%	5%	0%	9%	4%	6%
REFUSED	1%	0%	1%	0%	0%	0%	5%	0%	0%	1%	0%
DON'T KNOW	4%	6%	4%	0%	3%	2%	5%	14%	0%	6%	0%
N	99	17	81	1	31	41	20	7	11	71	17

EC10. Does this location have any on-site electricity generators?	Total	PG&E	SCE	SDG&E	Extra Large	Large	Medium	Small	Com-mercial	Industrial	Insti-tutional
Yes,for backup/standby purposes only	51%	53%	51%	0%	61%	54%	30%	43%	82%	39%	76%
Yes, as an everyday supplement or replacement for electricity purchases from the grid	5%	12%	4%	0%	10%	5%	0%	0%	9%	4%	6%
No	43%	29%	46%	100%	26%	41%	70%	57%	9%	55%	18%
REFUSED	1%	6%	0%	0%	3%	0%	0%	0%	0%	1%	0%
N	99	17	81	1	31	41	20	7	11	71	17

EC10a. What percent of this location's electricity load can be met by your on-site generation?	Total	PG&E	SCE	SDG&E	Extra Large	Large	Medium	Small	Com-mercial	Industrial	Insti-tutional
0	2%	0%	2%	0%	0%	4%	0%	0%	0%	3%	0%
1	11%	18%	9%	0%	18%	4%	17%	0%	10%	16%	0%
2	4%	0%	5%	0%	0%	8%	0%	0%	0%	3%	7%
5	4%	0%	5%	0%	5%	0%	0%	33%	0%	6%	0%
10	2%	0%	2%	0%	5%	0%	0%	0%	0%	3%	0%
15	2%	0%	2%	0%	0%	4%	0%	0%	0%	3%	0%
35	2%	0%	2%	0%	5%	0%	0%	0%	0%	3%	0%
40	4%	0%	5%	0%	5%	4%	0%	0%	0%	6%	0%
45	2%	9%	0%	0%	0%	0%	17%	0%	0%	3%	0%
50	5%	0%	7%	0%	5%	4%	0%	33%	10%	3%	7%
60	2%	0%	2%	0%	0%	4%	0%	0%	0%	3%	0%
70	2%	9%	0%	0%	0%	4%	0%	0%	0%	0%	7%
75	2%	0%	2%	0%	0%	0%	17%	0%	0%	0%	7%
80	4%	0%	5%	0%	9%	0%	0%	0%	0%	3%	7%
85	2%	9%	0%	0%	0%	4%	0%	0%	0%	0%	7%
90	2%	0%	2%	0%	0%	4%	0%	0%	10%	0%	0%
100	33%	36%	32%	0%	41%	29%	17%	33%	40%	19%	57%
125	4%	0%	5%	0%	5%	4%	0%	0%	10%	3%	0%
200	2%	0%	2%	0%	0%	4%	0%	0%	0%	3%	0%
400	2%	0%	2%	0%	0%	0%	17%	0%	0%	3%	0%
Don't know	11%	18%	9%	0%	5%	17%	17%	0%	20%	13%	0%
Mean	72	67	74	.	63	72	124	52	83	64	83
N	55	11	44	0	22	24	6	3	10	31	14

EC10b. Are their legal restrictions on the number of hours your on-site system can run during the summer?	Total	PG&E	SCE	SDG&E	Extra Large	Large	Medium	Small	Com-mercial	Industrial	Insti-tutional
Yes	67%	55%	70%	0%	59%	75%	50%	100%	70%	61%	79%
No	27%	36%	25%	0%	32%	25%	33%	0%	20%	32%	21%
REFUSED	2%	0%	2%	0%	0%	0%	17%	0%	0%	3%	0%
DON'T KNOW	4%	9%	2%	0%	9%	0%	0%	0%	10%	3%	0%
N	55	11	44	0	22	24	6	3	10	31	14

CLOSE

CL1. Do you have any final comments or suggestions about demand response programs being offered by [UTILITY]?	Total	PG&E	SCE	SDG&E	Extra Large	Large	Medium	Small	Com-mercial	Industrial	Insti-tutional
No suggestions/comments	69%	59%	70%	100%	65%	78%	60%	57%	64%	68%	76%
RECORD AND PROBE	32%	47%	30%	0%	35%	22%	45%	43%	36%	34%	24%
REFUSED	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
DON'T KNOW	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
N	99	17	81	1	31	41	20	7	11	71	17

C4. 2005 DRP Participant Survey Results

2005 DRP Participant Customer Survey

PROGRAM SATISFACTION

PS1. How long have you been participating in the California Demand Reserves Partnership, or DRP, program?	Percent of Responses
1 year	27%
2 years	23%
3 years	31%
More than 3 years	12%
DON'T KNOW	8%
N	26

PS2. What other demand response programs or tariffs, if any, were you participating in before you signed up for DRP?	Percent of Responses
No other program	42%
Interruptible or non-firm tariff	4%
Critical Peak Pricing (CPP)	8%
Demand Bidding Program (DBP)	8%
Base Interruptible Program (BIP)	12%
Optional Binding Mandatory Curtailment (OBMC)	4%
Scheduled Load Reduction Program (SLRP)	0%
Rolling Blackout Reduction Program (RBRP	4%
OTHER-RECORD	35%
REFUSED	0%
DON'T KNOW	4%
N	26

PS2A. What other rates or programs, if any, did you consider as alternatives to signing up for the DRP program?	Percent of Responses
No other program	65%
Interruptible or non-firm tariff	4%
Critical Peak Pricing (CPP)	4%
Demand Bidding Program (DBP)	8%
Base Interruptible Program (BIP)	19%
Optional Binding Mandatory Curtailment (OBMC)	0%
Scheduled Load Reduction Program (SLRP)	0%
Rolling Blackout Reduction Program (RBRP	4%
OTHER-RECORD	8%
REFUSED	0%
DON'T KNOW	4%
N	26

PS2B. What was the primary reason for signing up for the DRP program?	Percent of Responses
Save money on energy costs/bills	38%
Being able to participate without significantly affecting business operations	4%
Being a good corporate citizen	19%
Avoiding rolling blackouts	12%
Third party influence	23%
Only program available	4%
N	26

PS2C. Which features of the DRP program are most attractive to your organization?	Percent of Responses
Pricing/incentives	58%
Penalty levels or structure	27%
Event notification	12%
Event frequency	4%
Event duration	0%
Length of settlement process	0%
Through third party - not utility	4%
Only program available	0%
For a good cause	12%
OTHER - RECORD	4%
REFUSED	0%
DON'T KNOW	4%
N	26

PS2D. Which features do you not like about the DRP program?	Percent of Responses
Pricing/incentives	42%
Penalty levels or structure	31%
Event notification	15%
Event frequency	23%
Event duration	12%
Length of settlement process	8%
Through third party - not utility	0%
Uncertainty about program's future	0%
Program complexity	8%
OTHER - RECORD	0%
REFUSED	0%
DON'T KNOW	8%
N	26

PS2E. How did you select the aggregator you currently work with for the DRP program?	Percent of Responses
Recommended by trade association	4%
Reviewed several aggregator offerings and chose best one	12%
Previous business relationship	4%
Selected one from list on website	4%
Selected by someone else in our organization	31%
OTHER - RECORD	62%
REFUSED	0%
DON'T KNOW	0%
N	26

PS3A. The enrollment process.	Percent of Responses
Very Satisfied	46%
Somewhat satisfied	46%
DON'T KNOW	8%
N	26

PS3B. The range of interruption options offered (i.e., 1-3, 1-5, or 1-8 hours).	Percent of Responses
Very Satisfied	50%
Somewhat satisfied	46%
Very dissatisfied	4%
N	26

PS3C. The nomination or bidding process.	Percent of Responses
Very Satisfied	46%
Somewhat satisfied	38%
Somewhat dissatisfied	8%
DON'T KNOW	8%
N	26

PS3D. The notification process for interruption events	Percent of Responses
Very Satisfied	46%
Somewhat satisfied	31%
Somewhat dissatisfied	12%
Very dissatisfied	12%
N	26

PS3E. The frequency of interruption events	Percent of Responses
Very Satisfied	12%
Somewhat satisfied	35%
Somewhat dissatisfied	27%
Very dissatisfied	27%
N	26

PS3F. The duration of interruption events	Percent of Responses
Very Satisfied	19%
Somewhat satisfied	54%
Somewhat dissatisfied	15%
Very dissatisfied	12%
N	26

PS3G. The capacity payment for participation	Percent of Responses
Very Satisfied	8%
Somewhat satisfied	38%
Somewhat dissatisfied	46%
Very dissatisfied	8%
N	26

PS3H. The energy payment for participation	Percent of Responses
Very Satisfied	4%
Somewhat satisfied	46%
Somewhat dissatisfied	38%
Very dissatisfied	8%
DON'T KNOW	4%
N	26

PS3I. The timeliness of payments for participation	Percent of Responses
Very Satisfied	15%
Somewhat satisfied	31%
Somewhat dissatisfied	23%
Very dissatisfied	31%
N	26

PS3J. The level of penalties for failure to curtail during interruption events	Percent of Responses
Very Satisfied	12%
Somewhat satisfied	35%
Somewhat dissatisfied	19%
Very dissatisfied	23%
REFUSED	4%
DON'T KNOW	8%
N	26

PS3K. The information provided regarding your performance on curtailments	Percent of Responses
Very Satisfied	19%
Somewhat satisfied	38%
Somewhat dissatisfied	19%
Very dissatisfied	8%
DON'T KNOW	15%
N	26

PS4. Overall, how satisfied are you with your participation in this program?	Percent of Responses
Very Satisfied	27%
Somewhat satisfied	46%
Somewhat dissatisfied	27%
N	26

PS4A. Could you briefly summarize why your experience with the DRP program has been unsatisfactory?	Percent of Responses
Pricing/baseline calculations	29%
Complex/confusing	29%
Frequency/duration/time of day	29%
Slow feedback	14%
Inconvenient	14%
RECORD VERBATIM	0%
REFUSEED	14%
DON'T KNOW	0%
N	7

PS4B	Percent of Responses
More satisfied this year	14%
Less satisfied this year or	43%
Equally satisfied this year	14%
We did not PARTICIPATE in 2004	29%
N	7

PS4C	Percent of Responses
RECORD VERBATIM	100%
REFUSED	0%
DON'T KNOW	0%
N	1

PS4D	Percent of Responses
RECORD VERBATIM	100%
REFUSED	0%
DON'T KNOW	0%
N	3

PS5. Have changed your monthly nominations since you first enrolled in this program?	Percent of Responses
Yes	42%
No	46%
DON'T KNOW	12%
N	26

PS5A. Have you increased or decreased your monthly nomination?	Percent of Responses
INCREASED	36%
DECREASED	45%
VARIES from Month to Month	9%
REFUSED	9%
N	11

PS5B. Could you briefly summarize why you changed your monthly nomination?	Percent of Responses
Previous nominations were too much	0%
Changes in curtailment options forced cutback	9%
Able to increase nomination because of business/production	36%
Baseline calculation made previous level	36%
Cut back nomination because of business/production requirements	9%
RECORD VERBATIM	18%
REFUSED	0%
DON'T KNOW	0%
N	11

PS5C. In addition to monthly nominations, have you also made daily nominations?	Percent of Responses
Yes	12%
No	73%
DON'T KNOW	15%
N	26

PS5D. In about how many months did you make daily nominations in addition to monthly nominations? Would you say you made daily nominations:	Percent of Responses
Less than half the months in which you made monthly nominations	33%
Every month in which you made a monthly nomination	67%
N	3

2005 EVENT EXPERIENCE

EX1. How often was your organization called upon to curtail in 2005, not including test events?	Percent of Responses
Never	4%
2 Times	4%
5 Times	4%
7 Times	8%
8 Times	4%
9 Times	4%
10 Times	4%
12 Times	4%
14 Times	12%
15 Times	4%
19 Times	4%
20 Times	4%
25 Times	15%
30 Times	8%
60 Times	4%
Very often	4%
Don't know	12%
Mean	17.1
N	26

EX2. Does your organization have a pre-established curtailment strategy?	Percent of Responses
Yes	85%
No	15%
N	26

EX3. What specific actions do you take to reduce load during curtailment event(s)?	Percent of Responses
Turn off/reduced overhead lighting	42%
Turn off computers and other office equipment	27%
Reduce thermostat temperature setting	42%
Shut down some or all production processes	54%
Shift production to other day or period	42%
Shut down some or all refrigeration/cold storage	27%
Run back-up generators	15%
OTHER - RECORD	0%
REFUSED	0%
DON'T KNOW	0%
N	26

EX3A. To what extent are these load reductions centrally controlled, as opposed to being a diffuse set of manual actions? Would you say these load reductions are…	Percent of Responses
Entirely centrally controlled	42%
Partially centrally controlled OR	38%
Not at all centrally controlled	19%
N	26

EX5. What software, if any, do you use to track your energy usage and manage your load reductions?	Percent of Responses
InterAct or Interact II (PG&E)	4%
Energy Manager (SCE)	12%
OTHER - RECORD	69%
NONE	15%
N	26

EX5A. How useful has that software been in managing or planning your load reductions? Would you say…	Percent of Responses
Very Helpful	59%
Somewhat Helpful	32%
Not at all Helpful OR	5%
Never Used it	5%
N	22

EX5B. What aspects of the software have been the most useful in managing or planning your load reductions?	Percent of Responses
RECORD VERBATIM	100%
REFUSED	0%
DON'T KNOW	0%
N	20

EX6. Would you say that it is generally easy or difficult for your organization to curtail the amount of load required in the required timeframe? Would you say:	Percent of Responses
Very easy	19%
Somewhat easy	46%
Somewhat difficult OR	23%
Very difficult	12%
N	26

EX6A. Briefly, what is the main reason why your organization has found it [ANSWER TO EX6] to curtail in the required timeframe?	Percent of Responses
Planning/automated controls	38%
Third party help/other arrangements	15%
Does not interrupt production/operations	12%
Does interrupt production/operations	31%
Hard to monitor	8%
Lack of capibility/knowledge	19%
Do not know baselines/baseline problems	8%
RECORD VERBATIM	0%
REFUSED	0%
DON'T KNOW	0%
N	26

EX6A. Briefly, what is the main reason why your organization has found it VERY EASY to curtail in the required timeframe?	Percent of Responses
Planning/automated controls	80%
Third party help/other arrangements	20%
Does not interrupt production/operations	20%
Does interrupt production/operations	0%
Hard to monitor	0%
Lack of capibility/knowledge	0%
Do not know baselines/baseline problems	0%
RECORD VERBATIM	0%
REFUSED	0%
DON'T KNOW	0%
N	5

EX6A. Briefly, what is the main reason why your organization has found it SOMEWHAT EASY to curtail in the required timeframe?	Percent of Responses
Planning/automated controls	50%
Third party help/other arrangements	25%
Does not interrupt production/operations	17%
Does interrupt production/operations	33%
Hard to monitor	0%
Lack of capibility/knowledge	0%
Do not know baselines/baseline problems	0%
RECORD VERBATIM	0%
REFUSED	0%
DON'T KNOW	0%
N	12

EX6A. Briefly, what is the main reason why your organization has found it SOMWHAT DIFFICULT to curtail in the required timeframe?	Percent of Responses
Planning/automated controls	0%
Third party help/other arrangements	0%
Does not interrupt production/operations	0%
Does interrupt production/operations	50%
Hard to monitor	17%
Lack of capibility/knowledge	50%
Do not know baselines/baseline problems	17%
RECORD VERBATIM	0%
REFUSED	0%
DON'T KNOW	0%
N	6

EX6A. Briefly, what is the main reason why your organization has found it VERY DIFFICULT to curtail in the required timeframe?	Percent of Responses
Planning/automated controls	0%
Third party help/other arrangements	0%
Does not interrupt production/operations	0%
Does interrupt production/operations	33%
Hard to monitor	33%
Lack of capibility/knowledge	67%
Do not know baselines/baseline problems	33%
RECORD VERBATIM	0%
REFUSED	0%
DON'T KNOW	0%
N	3

OUTLOOK GOING FORWARD

GF1. Do you anticipate remaining in the DRP program next summer?	Percent of Responses
Yes	73%
No	19%
DON'T KNOW	8%
N	26

GF1A. What other rate or program would you be most likely to consider?	Percent of Responses
No other program	60%
Interruptible or non-firm tariff	0%
Critical Peak Pricing (CPP)	0%
Demand Bidding Program (DBP)	0%
Base Interruptible Program (BIP)	0%
Optional Binding Mandatory Curtailment (OBMC)	0%
Scheduled Load Reduction Program (SLRP)	0%
Rolling Blackout Reduction Program (RBRP	0%
OTHER-RECORD	40%
REFUSED	0%
DON'T KNOW	0%
N	5

GF1B. Which features of [PROGRAMS CITED IN GF1a] are most attractive to your organization?	Percent of Responses
Pricing/incentives	.
Penalty levels or structure	.
Event notification	.
Event frequency	.
Event duration	.
Length of settlement process	.
Reliability of supply	.
OTHER - RECORD	.
REFUSED	.
DON'T KNOW	.
N	0

GF2. In the last two years, have you considered participating in other demand response programs?	Percent of Responses
Yes	43%
No	48%
DON'T KNOW	10%
N	21

GF2A. Did you consider participating in other demand response programs in addition to or instead of participating in the DRP program?	Percent of Responses
In addition to DRP	33%
Instead of DRP	67%
N	9

GF2B. If yes, which programs appealed to you?	Percent of Responses
No other program	0%
Interruptible or non-firm tariff	0%
Critical Peak Pricing (CPP)	22%
Demand Bidding Program (DBP)	11%
Base Interruptible Program (BIP)	11%
Optional Binding Mandatory Curtailment (OBMC)	0%
Scheduled Load Reduction Program (SLRP)	0%
Rolling Blackout Reduction Program (RBRP	0%
OTHER-RECORD	67%
REFUSED	11%
DON'T KNOW	11%
N	9

GF2C. Which features of this program are most attractive to your organization?	Percent of Responses
Pricing/incentives	29%
Penalty levels or structure	0%
Event notification	0%
Event frequency	0%
Event duration	0%
Length of settlement process	0%
Reliability of supply	0%
OTHER - RECORD	43%
REFUSED	0%
DON'T KNOW	43%
N	7

GF2D. Which features did you not like about the programs you considered?	Percent of Responses
Pricing/incentives	14%
Penalty levels or structure	0%
Event notification	0%
Event frequency	0%
Event duration	0%
Length of settlement process	0%
Reliability of supply	0%
OTHER - RECORD	71%
REFUSED	0%
DON'T KNOW	14%
N	7

GF3. Are you aware of the Technical Assistance –Technology Incentive Program to help customers identify demand response load reduction opportunities within their facility and help offset the costs of implementing those opportunities?	Percent of Responses
Yes	81%
No	19%
N	26

GF3A. Are you planning to enroll in the Technical Assistance - Technology Incentive Program?	Percent of Responses
Yes	24%
No	38%
DON'T KNOW	38%
N	21

GF3B. Which aspects of the Technical Assistance Incentive Program are you planning to use?	Percent of Responses
Preliminary audit	0%
Detailed technical audit	0%
Financial incentives to install demand response measures	40%
OTHER ASPECTS	20%
REFUSED	0%
DON'T KNOW	40%
N	5

GF4. Under the terms of the DRP program, service interruptions are limited to a maximum of 24 hours per month, or a total of 150 hours per year. In a worst-case scenario where the maximum number of interruptions was called, how likely is it that your organization would remain in the DRP program?	Percent of Responses
Very likely	15%
Somewhat likely	42%
Somewhat unlikely OR	15%
Very unlikely	27%
N	26

GF4A. What is the upper limit on the number of hours of service interruption that your organization could withstand in a worst-case scenario before considering leaving the DRP program?	Percent of Responses
2 to 16	18%
24 to 30	36%
50 to 80	18%
500+	18%
RECORD VERBATIM	0%
REFUSED	0%
DON'T KNOW	9%
N	11

GF4B. If these upper limits actually occurred, which of the following actions are you most likely to take?	Percent of Responses
Go to a firm service rate with no demand response participation	20%
Go to a firm service rate and consider participating in other demand response programs	40%
Go to a non-firm service rate or increase our non-firm load	10%
Other - RECORD VERBATIM	20%
DON'T KNOW	10%
N	10

GF5. The DRP program is currently scheduled to run through 2006. Which of the following statements best describes your organization's preference regarding the future role of the DRP program for 2007 and beyond?	Percent of Responses
We would like to see the DRP remain in place in its current form	19%
We would like to see a program like the DRP, but with changes	69%
We don't care whether a program like the DRP is available or not	12%
N	26

GF5A. What changes would you like to see to the DRP program for 2007 and beyond?	Percent of Responses
Better baseline/advance notification	28%
More info/better/faster reporting	33%
More/better incentives	39%
Change/explain calculations	33%
RECORD VERBATIM	0%
REFUSED	0%
DON'T KNOW	6%
N	18

GF6. If the DRP program were discontinued after 2006, which of the following actions would you be most likely to take?	Percent of Responses
Go to a firm service rate with no demand response participation	4%
Go to a firm service rate and consider participating in other demand response programs	50%
Go to a non-firm service rate or increase our non-firm load	12%
None of the above	19%
DON'T KNOW	15%
N	26

FIRMOGRAPHIC CHARACTERISTICS

EC1. What is the main activity performed at this location?	Percent of Responses
Office	8%
Retail (non-food)	0%
College/university	42%
School	0%
Grocery store	4%
Convenience store	0%
Restaurant	0%
Health care/hospital	0%
Hotel or motel	0%
Warehouse	0%
Personal Service	0%
Community Service/Church/Temple/Municipa	19%
Industrial Electronic & Machinery	0%
Industrial Mining Metals Stone Glass Con	4%
Industrial Petroleum Plastic Rubber and	8%
Other Industrial	12%
Agricultural	0%
Transportation/Telecommunications/Utilit	4%
OTHER -RECORD VERBATIM	0%
REFUSED	0%
DON'T KNOW	0%
N	26

EC9A. Which of the following is the LARGEST end use in terms of electricity consumption for this facility?	Percent of Responses
Lighting	19%
HVAC	35%
Continuous processing	27%
Batch processing	4%
Refrigeration	15%
N	26

EC9B. And which would you say used the SECOND most electricity?	Percent of Responses
Lighting	38%
HVAC	31%
Continuous processing	8%
Batch processing	15%
REFUSED	4%
DON'T KNOW	4%
N	26

EC10. Does this location have any on-site electricity generators?	Percent of Responses
Yes, for backup/standby purposes only	38%
Yes, as an everyday supplement or replacement for electricity purchases from the grid	15%
No generators	46%
N	26

EC10A. What percent of this location's electricity load can be met by your on-site generation?	Percent of Responses
2	7%
5	14%
7	7%
10	14%
20	7%
30	7%
50	7%
60	7%
70	7%
90	7%
100	14%
Mean	40
N	14

EC10B. Are their legal restrictions on the number of hours your on-site system can run during the summer?	Percent of Responses
Yes	64%
No	36%
N	14

CLOSE

CL1. Do you have any final comments or suggestions about the DRP program?	Percent of Responses
No Comments	81%
RECORD VERBATIM	19%
REFUSED	0%
DON'T KNOW	0%
N	26

APPENDIX D
IMPACT TABLES

D1. CPP and DBP Hourly Impact Tables

D1. CPP AND DBP HOURLY IMPACT TABLES

The CPP and DBP Hourly Impact Tables included in Appendix D1 contain the MW impact estimates for each hour of every event during the summer of 2005 for each of the three utilities. The hourly impact estimates for each program participant are calculated as the difference between the estimated hourly base load for the participant, estimated using five different representative day baseline methods, and the actual hourly event day load[1]. The overall program impact for a given event hour is then simply the sum of the hourly impacts across all CPP program participants or DBP bidders within a given service territory for a particular event:

$$\mathrm{Im}\,pact_t = \sum_n \left(k\hat{W}_{n,t} - kW_{n,t} \right)$$

where,

Impact_t = Difference between the estimated base load and the actual load at time t,

$k\hat{W}_{n,t}$ = Estimated base load of customer n at time t, and

$kW_{n,t}$ = Actual load of customer n at time t.

The tables in this appendix include the hourly impact estimates from two of the counting alternatives analyzed for this evaluation. These include the counting all impacts (both positive and negative) alternative and the counting positive impacts only alternative.

The Exhibits in this Appendix include the following:

- D1-1 Hourly Impact Estimates for PG&E CPP Participants – Summer 2005 Events
- D1-2 Hourly Impact Estimates for SCE CPP Participants – Summer 2005 Events
- D1-3 Hourly Impact Estimates for SDG&E CPP Participants – Summer 2005 Events
- D1-4a/4b Hourly Impact Estimates for PG&E DBP Participants – Summer 2005 Events
  - 4a includes events 1-7, for which the DBP bids were lost
  - 4b includes events 8-17, for which all bids were captured
- D1-5 Hourly Impact Estimates for SCE DBP Participants – Summer 2005 Events
- D1-6 Hourly Impact Estimates for SDG&E DBP Participants – Summer 2005 Events

[1] The five representative day baselines included in the hourly impact tables are the 3-Day, 3-Day Coincident, 10-Day, 10-Day Adjusted and 8-Day baselines. Each of these representative day baselines is described in Chapter 6.

Exhibit D1-1
Hourly Impact Estimates for PG&E CPP Participants – Summer 2005 Events

Utility	Event	Event Length	Baseline	N	n	Hourly Impacts (in MW)												Utility Reported
						All Impacts						Positive Impacts						
						12-1	1-2	2-3	3-4	4-5	5-6	12-1	1-2	2-3	3-4	4-5	5-6	
PG&E	7/1/05	6 hours	3-Day	180	174	17.5	18.5	20.3	19.0	15.6	13.0	18.3	19.2	20.8	19.7	16.1	13.5	16.4
PG&E	7/1/05	6 hours	3-Day Coin	180	174	13.2	12.7	14.5	13.0	12.0	10.5	14.4	14.3	16.3	14.9	12.9	11.2	-
PG&E	7/1/05	6 hours	10-Day	180	174	9.0	8.9	10.2	9.3	8.0	7.0	12.0	12.2	13.5	12.2	10.0	8.7	-
PG&E	7/1/05	6 hours	10-Day Adj	180	174	15.9	15.8	17.1	15.9	14.5	13.0	16.5	16.7	18.1	16.9	15.0	13.4	-
PG&E	7/1/05	6 hours	8-Day	180	174	9.3	9.2	10.6	9.5	8.1	7.2	12.2	12.4	13.8	12.4	10.2	8.9	-
PG&E	7/12/05	6 hours	3-Day	193	187	9.1	10.3	10.6	10.3	9.2	7.2	12.0	12.6	13.6	13.2	11.7	9.4	9.7
PG&E	7/12/05	6 hours	3-Day Coin	193	187	3.1	2.9	3.7	4.8	4.9	3.4	8.6	8.9	9.3	10.1	9.4	7.5	-
PG&E	7/12/05	6 hours	10-Day	193	187	-2.2	-2.4	-1.7	-0.5	0.1	-0.3	7.4	7.6	7.9	8.2	7.6	6.4	-
PG&E	7/12/05	6 hours	10-Day Adj	193	187	4.9	4.5	5.1	6.2	6.5	5.8	8.3	8.1	8.9	9.7	9.2	8.2	-
PG&E	7/12/05	6 hours	8-Day	193	187	-1.8	-2.1	-1.3	-0.3	0.2	-0.3	7.5	7.6	8.0	8.2	7.5	6.3	-
PG&E	7/13/05	6 hours	3-Day	225	218	9.0	10.4	11.7	10.5	9.5	7.6	12.2	13.0	14.2	13.1	11.5	9.5	9.6
PG&E	7/13/05	6 hours	3-Day Coin	225	218	2.7	2.6	4.4	4.7	4.7	3.4	8.7	9.4	9.9	9.9	8.9	7.2	-
PG&E	7/13/05	6 hours	10-Day	225	218	-3.6	-3.5	-1.9	-1.5	-0.8	-1.0	6.8	7.3	7.7	7.4	6.4	5.4	-
PG&E	7/13/05	6 hours	10-Day Adj	225	218	4.5	4.4	5.9	6.2	6.6	6.0	8.6	8.7	9.5	9.8	9.0	8.2	-
PG&E	7/13/05	6 hours	8-Day	225	218	-3.2	-3.2	-1.5	-1.3	-0.7	-0.9	7.0	7.4	7.8	7.4	6.3	5.4	-
PG&E	7/14/05	6 hours	3-Day	193	185	13.2	13.8	13.6	11.4	8.4	6.9	15.1	15.6	15.4	13.6	10.7	9.0	10.9
PG&E	7/14/05	6 hours	3-Day Coin	193	185	7.5	6.8	7.2	6.4	4.6	3.6	11.4	10.9	10.6	10.0	8.2	7.0	-
PG&E	7/14/05	6 hours	10-Day	193	185	2.1	1.4	1.5	0.8	-0.5	-0.4	9.5	9.0	9.0	8.3	6.5	5.7	-
PG&E	7/14/05	6 hours	10-Day Adj	193	185	9.0	8.1	8.1	7.3	5.7	5.4	11.8	10.6	10.3	9.8	8.1	7.8	-
PG&E	7/14/05	6 hours	8-Day	193	185	2.5	1.6	1.9	1.0	-0.4	-0.4	9.9	9.2	9.1	8.2	6.5	5.7	-
PG&E	7/15/05	6 hours	3-Day	193	185	12.7	14.8	14.7	12.0	9.4	7.4	13.9	15.7	15.7	13.3	10.7	8.5	11.4
PG&E	7/15/05	6 hours	3-Day Coin	193	185	7.1	7.8	8.3	7.0	5.5	3.9	10.2	11.2	11.1	9.7	8.2	6.4	-
PG&E	7/15/05	6 hours	10-Day	193	185	1.6	2.4	2.6	1.5	0.5	0.0	7.6	8.5	8.4	6.8	5.5	4.6	-
PG&E	7/15/05	6 hours	10-Day Adj	193	185	8.5	9.0	9.2	7.9	6.7	5.9	10.9	11.4	11.2	9.9	8.6	7.5	-
PG&E	7/15/05	6 hours	8-Day	193	185	2.0	2.6	3.0	1.6	0.6	0.0	7.7	8.4	8.5	6.8	5.4	4.5	-
PG&E	7/18/05	6 hours	3-Day	194	187	11.8	13.7	14.4	12.5	9.4	6.8	13.5	15.1	15.3	13.6	11.1	9.1	11.8
PG&E	7/18/05	6 hours	3-Day Coin	194	187	6.2	6.8	7.9	7.5	5.6	3.4	9.4	10.3	10.7	10.2	8.9	7.1	-
PG&E	7/18/05	6 hours	10-Day	194	187	0.6	1.3	2.2	1.9	0.5	-0.6	7.1	7.5	8.0	7.4	6.1	5.1	-
PG&E	7/18/05	6 hours	10-Day Adj	194	187	7.6	8.0	8.8	8.4	6.7	5.3	9.7	10.0	10.5	10.2	8.8	7.9	-
PG&E	7/18/05	6 hours	8-Day	194	187	1.0	1.4	2.6	2.0	0.6	-0.6	7.4	7.6	8.2	7.5	6.2	5.0	-
PG&E	8/5/05	6 hours	3-Day	209	198	9.7	11.3	10.6	10.5	10.5	9.6	12.1	13.5	13.2	12.8	12.0	10.7	9.7
PG&E	8/5/05	6 hours	3-Day Coin	209	198	2.2	3.9	2.8	4.0	4.8	5.1	7.0	8.3	7.4	7.9	7.3	6.9	-
PG&E	8/5/05	6 hours	10-Day	209	198	0.0	1.4	0.6	1.5	2.9	3.1	6.7	7.4	7.0	7.3	6.9	6.5	-
PG&E	8/5/05	6 hours	10-Day Adj	209	198	2.7	3.9	3.1	3.9	5.6	5.6	8.0	8.9	8.5	8.9	8.1	7.8	-
PG&E	8/5/05	6 hours	8-Day	209	198	0.4	1.8	0.9	1.8	3.2	3.3	6.8	7.6	7.1	7.4	7.0	6.6	-
PG&E	8/8/05	6 hours	3-Day	214	202	11.5	12.6	13.2	13.9	12.5	11.4	14.5	15.0	14.6	15.2	13.5	12.0	11.9
PG&E	8/8/05	6 hours	3-Day Coin	214	202	4.0	5.3	5.3	7.5	6.8	7.0	8.8	9.2	9.1	10.2	8.9	8.5	-
PG&E	8/8/05	6 hours	10-Day	214	202	1.8	2.7	3.2	5.0	5.0	4.9	8.4	8.5	8.2	8.7	7.7	7.0	-
PG&E	8/8/05	6 hours	10-Day Adj	214	202	4.5	5.2	5.6	7.3	7.6	7.4	10.5	10.0	10.1	10.7	9.7	9.0	-
PG&E	8/8/05	6 hours	8-Day	214	202	2.1	3.1	3.4	5.3	5.2	5.1	8.7	8.8	8.3	8.9	7.9	7.2	-
PG&E	9/29/05	6 hours	3-Day	279	261	5.0	5.2	5.7	9.7	8.4	6.2	9.8	11.5	11.5	13.9	12.8	11.0	n/a
PG&E	9/29/05	6 hours	3-Day Coin	279	261	-2.5	-3.6	-2.7	1.4	0.6	-0.5	5.8	6.6	6.8	9.1	8.0	7.2	-
PG&E	9/29/05	6 hours	10-Day	279	261	-8.0	-9.8	-9.5	-5.3	-5.7	-5.2	5.5	6.1	6.1	7.8	7.2	6.9	-
PG&E	9/29/05	6 hours	10-Day Adj	279	261	4.1	1.8	2.0	5.4	4.2	3.8	9.1	8.9	8.8	11.0	10.0	9.5	-
PG&E	9/29/05	6 hours	8-Day	279	261	-7.3	-9.3	-9.0	-4.7	-5.3	-4.9	5.6	6.1	6.1	7.9	7.1	7.0	-

Exhibit D1-2
Hourly Impact Estimates for SCE CPP Participants – Summer 2005 Events

Utility	Event	Event Length	Baseline	N	n	Hourly CPP Impacts (in MW) All Impacts 12-1	1-2	2-3	3-4	4-5	5-6	Positive Impacts 12-1	1-2	2-3	3-4	4-5	5-6	Utility Reported
SCE	7/21/05	6 hours	3-Day	8	8	1.0	1.0	0.9	1.1	0.9	0.7	1.2	1.0	0.9	1.1	0.9	0.7	0.9
SCE	7/21/05	6 hours	3-Day Coin	8	8	0.7	0.5	0.6	0.9	0.8	0.6	0.8	0.7	0.7	0.9	0.9	0.8	-
SCE	7/21/05	6 hours	10-Day	8	8	0.7	0.5	0.5	0.8	0.6	0.4	0.9	0.7	0.6	0.8	0.7	0.5	-
SCE	7/21/05	6 hours	10-Day Adj	8	8	0.6	0.5	0.5	0.7	0.6	0.3	0.8	0.7	0.6	0.7	0.7	0.5	-
SCE	7/21/05	6 hours	8-Day	8	8	0.6	0.5	0.5	0.8	0.7	0.4	0.9	0.7	0.7	0.8	0.8	0.5	-
SCE	7/22/05	6 hours	3-Day	8	8	1.4	1.4	1.3	1.2	1.0	0.9	1.4	1.4	1.3	1.2	1.0	1.0	1.2
SCE	7/22/05	6 hours	3-Day Coin	8	8	1.0	0.9	1.0	0.9	1.0	0.8	1.0	0.9	1.0	1.0	1.0	0.9	-
SCE	7/22/05	6 hours	10-Day	8	8	1.0	0.9	0.9	0.9	0.8	0.6	1.1	0.9	0.9	0.9	0.8	0.7	-
SCE	7/22/05	6 hours	10-Day Adj	8	8	1.0	0.8	0.8	0.8	0.7	0.5	1.0	0.9	0.9	0.9	0.7	0.6	-
SCE	7/22/05	6 hours	8-Day	8	8	1.0	0.8	0.9	0.9	0.8	0.6	1.1	0.9	0.9	1.0	0.8	0.7	-
SCE	7/25/05	6 hours	3-Day	8	8	1.2	1.2	1.0	1.1	1.0	0.8	1.2	1.2	1.0	1.1	1.0	0.8	1.0
SCE	7/25/05	6 hours	3-Day Coin	8	8	0.8	0.7	0.7	0.8	0.9	0.7	0.8	0.7	0.7	0.8	0.9	0.8	-
SCE	7/25/05	6 hours	10-Day	8	8	0.8	0.7	0.6	0.7	0.7	0.5	0.8	0.7	0.6	0.8	0.7	0.6	-
SCE	7/25/05	6 hours	10-Day Adj	8	8	0.7	0.6	0.5	0.7	0.6	0.4	0.8	0.7	0.6	0.7	0.7	0.6	-
SCE	7/25/05	6 hours	8-Day	8	8	0.8	0.7	0.6	0.8	0.7	0.5	0.8	0.7	0.7	0.8	0.8	0.6	-
SCE	8/26/05	6 hours	3-Day	8	8	1.2	1.2	1.3	1.3	1.1	1.0	1.2	1.2	1.3	1.3	1.1	1.0	1.2
SCE	8/26/05	6 hours	3-Day Coin	8	8	1.0	1.1	1.3	1.2	1.0	0.9	1.1	1.1	1.3	1.2	1.0	0.9	-
SCE	8/26/05	6 hours	10-Day	8	8	0.9	0.9	1.1	1.1	0.9	0.8	1.0	0.9	1.1	1.1	0.9	0.8	-
SCE	8/26/05	6 hours	10-Day Adj	8	8	1.1	1.0	1.2	1.2	0.9	0.8	1.2	1.1	1.3	1.2	1.0	0.8	-
SCE	8/26/05	6 hours	8-Day	8	8	0.9	0.9	1.1	1.1	0.9	0.8	1.0	0.9	1.1	1.1	0.9	0.8	-
SCE	8/29/05	6 hours	3-Day	8	8	1.2	1.0	0.9	0.9	1.0	0.7	1.2	1.0	1.0	0.9	1.0	0.8	0.9
SCE	8/29/05	6 hours	3-Day Coin	8	8	1.0	1.0	0.9	0.7	0.9	0.7	1.0	1.0	1.0	0.8	0.9	0.8	-
SCE	8/29/05	6 hours	10-Day	8	8	0.9	0.7	0.7	0.6	0.8	0.5	1.0	0.8	0.8	0.8	0.8	0.6	-
SCE	8/29/05	6 hours	10-Day Adj	8	8	1.1	0.9	0.8	0.7	0.8	0.6	1.1	0.9	1.0	1.0	0.9	0.7	-
SCE	8/29/05	6 hours	8-Day	8	8	0.9	0.8	0.7	0.6	0.8	0.6	1.0	0.8	0.8	0.8	0.8	0.7	-
SCE	8/30/05	6 hours	3-Day	8	8	0.4	0.1	0.3	0.4	0.6	0.8	0.4	0.1	0.3	0.4	0.6	0.9	0.4
SCE	8/30/05	6 hours	3-Day Coin	8	8	0.2	0.0	0.3	0.2	0.4	0.7	0.3	0.1	0.3	0.2	0.5	0.9	-
SCE	8/30/05	6 hours	10-Day	8	8	0.1	-0.2	0.1	0.1	0.3	0.6	0.3	0.1	0.1	0.2	0.5	0.7	-
SCE	8/30/05	6 hours	10-Day Adj	8	8	0.3	-0.1	0.2	0.2	0.4	0.6	0.4	0.1	0.2	0.3	0.6	0.8	-
SCE	8/30/05	6 hours	8-Day	8	8	0.1	-0.2	0.1	0.1	0.3	0.6	0.3	0.1	0.1	0.2	0.5	0.8	-
SCE	8/31/05	6 hours	3-Day	8	8	1.0	1.0	1.1	1.0	1.0	0.8	1.0	1.0	1.1	1.0	1.0	0.9	1.0
SCE	8/31/05	6 hours	3-Day Coin	8	8	0.8	0.9	1.1	0.9	0.9	0.8	0.9	0.9	1.1	0.9	0.9	0.8	-
SCE	8/31/05	6 hours	10-Day	8	8	0.8	0.7	0.8	0.8	0.8	0.6	0.9	0.8	0.9	0.9	0.9	0.7	-
SCE	8/31/05	6 hours	10-Day Adj	8	8	0.9	0.8	1.0	0.9	0.9	0.7	1.0	0.8	1.0	1.0	1.0	0.8	-
SCE	8/31/05	6 hours	8-Day	8	8	0.8	0.7	0.8	0.8	0.8	0.7	0.9	0.8	0.9	0.9	0.9	0.7	-
SCE	9/15/05	6 hours	3-Day	8	8	0.2	0.6	0.8	0.6	1.0	0.8	0.2	0.8	0.8	0.8	1.1	0.8	0.7
SCE	9/15/05	6 hours	3-Day Coin	8	8	0.1	0.5	0.6	0.5	0.9	0.7	0.2	0.7	0.8	0.7	0.9	0.8	-
SCE	9/15/05	6 hours	10-Day	8	8	0.0	0.4	0.4	0.4	0.8	0.6	0.2	0.7	0.7	0.7	0.8	0.7	-
SCE	9/15/05	6 hours	10-Day Adj	8	8	0.1	0.5	0.6	0.5	0.8	0.7	0.3	0.8	0.7	0.8	0.9	0.8	-
SCE	9/15/05	6 hours	8-Day	8	8	0.0	0.4	0.4	0.4	0.8	0.6	0.2	0.7	0.7	0.7	0.9	0.7	-
SCE	9/20/05	6 hours	3-Day	8	8	0.9	1.1	1.1	1.0	1.3	0.8	0.9	1.1	1.1	1.1	1.3	0.8	1.0
SCE	9/20/05	6 hours	3-Day Coin	8	8	1.1	1.0	0.9	0.8	1.1	0.7	1.1	1.0	0.9	0.9	1.1	0.7	-
SCE	9/20/05	6 hours	10-Day	8	8	0.8	0.8	0.8	0.8	1.0	0.7	0.9	0.9	0.9	0.9	1.0	0.7	-
SCE	9/20/05	6 hours	10-Day Adj	8	8	0.9	1.0	1.0	0.9	1.0	0.7	0.9	1.0	1.0	0.9	1.0	0.7	-
SCE	9/20/05	6 hours	8-Day	8	8	0.8	0.9	0.8	0.8	1.0	0.7	0.9	0.9	0.9	0.9	1.0	0.7	-
SCE	9/22/05	6 hours	3-Day	8	8	1.0	1.0	1.1	1.0	1.0	0.6	1.0	1.0	1.1	1.0	1.1	0.8	0.9
SCE	9/22/05	6 hours	3-Day Coin	8	8	1.0	0.9	0.9	0.8	0.9	0.5	1.0	0.9	0.9	0.8	1.0	0.7	-
SCE	9/22/05	6 hours	10-Day	8	8	0.7	0.8	0.8	0.8	0.8	0.5	0.8	0.8	0.8	0.8	0.9	0.7	-
SCE	9/22/05	6 hours	10-Day Adj	8	8	0.8	0.9	0.9	0.9	0.8	0.6	0.9	1.0	0.9	0.9	0.9	0.8	-
SCE	9/22/05	6 hours	8-Day	8	8	0.8	0.8	0.8	0.8	0.8	0.6	0.8	0.9	0.8	0.8	0.9	0.7	-
SCE	9/28/05	6 hours	3-Day	8	8	1.0	0.8	1.1	0.8	1.0	0.8	1.0	0.9	1.1	0.8	1.0	0.8	0.9
SCE	9/28/05	6 hours	3-Day Coin	8	8	1.0	0.7	0.9	0.8	1.0	0.6	1.0	0.8	0.9	0.8	1.0	0.6	-
SCE	9/28/05	6 hours	10-Day	8	8	0.7	0.6	0.7	0.7	0.9	0.7	0.8	0.8	0.9	0.8	0.9	0.7	-
SCE	9/28/05	6 hours	10-Day Adj	8	8	0.8	0.6	0.8	0.7	0.9	0.7	0.8	0.8	0.8	0.8	0.9	0.7	-
SCE	9/28/05	6 hours	8-Day	8	8	0.8	0.6	0.7	0.7	0.9	0.7	0.8	0.8	0.8	0.8	0.9	0.7	-
SCE	9/29/05	6 hours	3-Day	8	8	1.0	1.1	1.3	0.8	0.8	0.6	1.0	1.1	1.3	0.8	1.0	0.8	0.9
SCE	9/29/05	6 hours	3-Day Coin	8	8	1.0	1.0	1.1	0.8	0.8	0.5	1.0	1.0	1.1	0.9	0.9	0.6	-
SCE	9/29/05	6 hours	10-Day	8	8	0.7	0.8	1.0	0.7	0.7	0.5	0.9	0.9	1.0	0.8	0.9	0.7	-
SCE	9/29/05	6 hours	10-Day Adj	8	8	0.8	0.9	1.0	0.7	0.7	0.5	0.9	0.9	1.0	0.8	0.9	0.7	-
SCE	9/29/05	6 hours	8-Day	8	8	0.8	0.9	0.9	0.7	0.7	0.5	0.9	0.9	1.0	0.8	0.9	0.7	-

Exhibit D1-3
Hourly Impact Estimates for SDG&E CPP Participants – Summer 2005 Events

Utility	Event	Baseline	N	n	Hourly Impacts (in MW)														
					All Impacts							Positive Impacts							Utility Reported
					11-12	12-1	1-2	2-3	3-4	4-5	5-6	11-12	12-1	1-2	2-3	3-4	4-5	5-6	
SDG&E	7/21/05	3-Day	87	85	6.4	2.5	1.2	0.9	4.0	5.7	6.3	8.2	4.9	4.2	3.6	5.4	7.1	7.4	4.0
SDG&E	7/21/05	3-Day Coin	87	85	3.2	0.2	-0.6	-0.4	2.1	2.2	2.9	5.8	3.7	3.1	2.8	4.2	4.5	4.7	-
SDG&E	7/21/05	10-Day	87	85	2.5	-0.7	-1.4	-1.4	1.1	2.1	2.8	5.6	3.5	2.9	2.6	3.8	4.6	4.7	-
SDG&E	7/21/05	10-Day Adj	87	85	4.0	1.1	0.1	0.1	2.9	4.0	4.7	6.3	3.8	3.5	3.3	4.9	5.8	5.9	-
SDG&E	7/21/05	8-Day	87	85	2.5	-0.8	-1.4	-1.5	1.0	1.6	2.4	5.8	3.5	3.0	2.6	3.8	4.2	4.4	-
SDG&E	7/22/05	3-Day	88	86	6.2	2.8	1.4	1.3	4.3	6.6	6.8	7.8	4.5	3.9	3.4	5.1	7.5	7.7	4.3
SDG&E	7/22/05	3-Day Coin	88	86	3.0	0.5	-0.5	-0.1	2.4	3.1	3.4	5.2	3.2	2.7	2.4	3.8	4.6	4.9	-
SDG&E	7/22/05	10-Day	88	86	2.3	-0.4	-1.3	-1.1	1.4	3.0	3.3	4.8	2.8	2.2	2.0	3.2	4.6	4.8	-
SDG&E	7/22/05	10-Day Adj	88	86	3.7	1.3	0.2	0.4	3.2	5.0	5.2	5.2	3.2	2.7	2.5	4.3	5.8	6.0	-
SDG&E	7/22/05	8-Day	88	86	2.3	-0.5	-1.4	-1.2	1.3	2.6	2.9	4.9	2.7	2.1	1.9	3.1	4.1	4.4	-
SDG&E	8/26/05	3-Day	105	102	9.1	5.7	3.5	3.4	7.1	8.4	8.2	10.6	7.2	5.0	4.6	8.4	9.8	9.6	6.5
SDG&E	8/26/05	3-Day Coin	105	102	7.0	3.5	1.6	1.2	3.2	3.9	3.9	9.2	5.9	3.8	3.2	5.2	6.0	6.0	-
SDG&E	8/26/05	10-Day	105	102	5.2	2.2	0.6	0.7	2.3	3.1	3.5	8.3	5.4	3.5	3.2	5.0	6.0	6.4	-
SDG&E	8/26/05	10-Day Adj	105	102	7.7	4.2	2.6	2.6	4.3	5.1	5.6	9.1	5.7	3.9	3.7	6.2	7.3	7.7	-
SDG&E	8/26/05	8-Day	105	102	5.1	2.1	0.5	0.7	1.9	2.8	3.3	8.4	5.4	3.6	3.3	4.8	5.7	6.3	-
SDG&E	9/29/05	3-Day	105	102	7.5	4.2	3.3	2.0	4.9	8.4	8.3	9.5	6.1	4.4	3.4	6.5	10.0	9.9	7.0
SDG&E	9/29/05	3-Day Coin	105	102	3.6	1.6	1.5	0.8	2.0	3.9	3.9	6.5	4.4	3.1	2.6	4.3	6.4	6.4	-
SDG&E	9/29/05	10-Day	105	102	3.7	1.0	0.4	-0.5	0.8	2.4	2.4	7.0	4.2	2.6	2.0	3.7	5.6	5.5	-
SDG&E	9/29/05	10-Day Adj	105	102	6.2	3.1	2.1	1.2	2.8	4.8	4.7	8.3	5.4	3.4	2.8	4.8	6.7	6.6	-
SDG&E	9/29/05	8-Day	105	102	3.7	1.0	0.4	-0.5	0.4	1.9	1.9	7.1	4.3	2.6	2.0	3.5	5.2	5.1	-
SDG&E	9/30/05	3-Day	105	102	7.5	4.6	3.1	2.6	5.6	9.3	9.1	8.8	5.5	4.0	3.5	6.8	10.0	10.0	7.0
SDG&E	9/30/05	3-Day Coin	105	102	3.6	2.0	1.3	1.4	2.8	4.8	4.7	5.7	3.9	2.8	2.7	4.6	6.6	6.5	-
SDG&E	9/30/05	10-Day	105	102	3.7	1.4	0.2	0.1	1.6	3.3	3.2	6.0	3.4	2.1	1.9	3.9	5.6	5.4	-
SDG&E	9/30/05	10-Day Adj	105	102	6.2	3.5	1.9	1.8	3.5	5.7	5.5	7.4	4.6	3.0	2.9	4.9	7.0	6.8	-
SDG&E	9/30/05	8-Day	105	102	3.7	1.4	0.2	0.1	1.2	2.8	2.7	6.1	3.4	2.0	1.9	3.6	5.3	5.1	-

Exhibit D1-4a
Hourly Impact Estimates for PG&E DBP Participants – Summer 2005 Events
Events 1-7 (missing bids) – Next 10 Events in D1-4b

Utility	Event	Event Length	Baseline	N	n	Hourly DBP Impacts (in MW)																
						All Impacts								Positive Impacts								Utility Reported
						12-1	1-2	2-3	3-4	4-5	5-6	6-7	7-8	12-1	1-2	2-3	3-4	4-5	5-6	6-7	7-8	
PG&E	7/12/05	8 hours	3-Day	27	18	11.3	10.5	10.2	10.1	10.2	8.3	11.1	11.4	11.3	10.5	10.3	10.2	10.2	8.4	11.1	11.4	10.4
PG&E	7/12/05	8 hours	3-Day Coin	27	18	5.9	5.6	5.6	5.3	4.3	2.7	5.8	6.6	6.4	6.1	6.5	6.5	5.0	3.4	6.2	7.1	-
PG&E	7/12/05	8 hours	10-Day	27	18	4.5	4.1	4.2	3.7	3.1	2.3	4.5	6.2	5.1	4.8	5.1	4.8	3.9	2.8	5.3	6.7	-
PG&E	7/12/05	8 hours	10-Day Adj	27	18	6.8	6.2	6.5	6.5	5.4	3.8	6.0	7.1	6.8	6.2	6.6	6.6	5.5	3.8	6.1	7.1	-
PG&E	7/12/05	8 hours	8-Day	27	18	4.4	3.9	4.0	3.5	2.8	2.1	4.7	6.1	4.9	4.6	4.7	4.4	3.6	2.6	5.0	6.5	-
PG&E	7/13/05	8 hours	3-Day	46	38	36.7	39.8	65.5	32.6	28.6	22.9	22.6	22.9	37.0	40.0	65.7	32.6	28.6	23.1	22.6	22.9	34.1
PG&E	7/13/05	8 hours	3-Day Coin	46	38	22.4	23.8	51.7	17.3	14.7	8.8	10.6	12.9	23.5	25.3	52.0	18.4	15.6	10.2	11.5	13.8	-
PG&E	7/13/05	8 hours	10-Day	46	38	22.2	23.2	51.0	17.1	13.2	8.9	9.8	11.4	22.9	24.6	51.3	18.1	14.5	10.2	10.9	12.4	-
PG&E	7/13/05	8 hours	10-Day Adj	46	38	22.7	24.4	52.1	18.4	14.5	10.1	10.3	11.8	23.3	25.3	52.2	18.9	14.9	10.7	11.2	12.2	-
PG&E	7/13/05	8 hours	8-Day	46	38	21.8	22.7	50.2	16.3	12.6	8.5	9.5	11.2	22.5	24.0	50.6	17.3	13.8	9.7	10.5	12.0	-
PG&E	7/14/05	8 hours	3-Day	29	23	21.4	21.0	20.2	21.0	22.6	20.2	14.7	10.6	21.4	21.1	20.3	21.2	22.6	20.3	15.1	11.8	19.2
PG&E	7/14/05	8 hours	3-Day Coin	29	23	10.4	10.3	10.3	11.3	12.5	11.8	7.6	3.8	10.8	11.3	12.4	13.7	14.6	12.2	9.1	7.0	-
PG&E	7/14/05	8 hours	10-Day	29	23	11.3	10.7	9.9	10.8	12.0	11.2	7.2	4.3	12.0	12.4	12.3	13.4	14.5	12.0	8.7	7.8	-
PG&E	7/14/05	8 hours	10-Day Adj	29	23	9.7	10.5	10.2	11.4	12.3	10.2	7.1	3.8	9.7	10.6	10.5	11.7	12.6	10.2	7.2	5.9	-
PG&E	7/14/05	8 hours	8-Day	29	23	11.2	10.2	9.5	10.6	12.0	11.3	7.2	4.7	11.8	12.0	11.9	13.1	14.4	12.1	8.8	8.0	-
PG&E	7/15/05	8 hours	3-Day	38	33	15.3	14.1	13.9	15.6	17.0	17.3	15.1	16.1	15.4	14.1	14.2	15.8	17.0	17.3	16.0	16.1	15.7
PG&E	7/15/05	8 hours	3-Day Coin	38	33	7.3	6.8	6.1	8.9	10.1	8.2	8.8	10.5	7.4	6.8	7.9	9.6	10.6	10.2	10.8	11.1	-
PG&E	7/15/05	8 hours	10-Day	38	33	6.4	6.1	4.8	6.9	7.9	7.2	7.6	10.1	7.1	6.6	7.1	8.3	9.2	9.4	9.8	10.8	-
PG&E	7/15/05	8 hours	10-Day Adj	38	33	6.4	5.9	6.2	8.0	9.0	9.1	9.4	10.8	6.5	6.1	6.9	8.4	9.1	9.2	10.0	10.8	-
PG&E	7/15/05	8 hours	8-Day	38	33	6.1	5.7	4.4	6.7	7.9	7.2	7.6	10.4	6.9	6.2	6.7	8.0	9.0	9.5	9.8	11.0	-
PG&E	7/18/05	8 hours	3-Day	9	8	6.9	6.8	6.2	6.2	6.7	6.7	6.3	5.6	6.9	6.8	6.2	6.2	6.7	6.7	6.3	5.6	6.4
PG&E	7/18/05	8 hours	3-Day Coin	9	8	3.3	3.7	3.7	3.9	3.4	3.3	2.9	2.3	3.3	3.7	3.7	3.9	3.4	3.3	2.9	2.3	-
PG&E	7/18/05	8 hours	10-Day	9	8	2.9	3.2	2.9	2.8	2.7	2.6	2.4	2.7	2.9	3.2	2.9	2.8	2.7	2.7	2.4	2.7	-
PG&E	7/18/05	8 hours	10-Day Adj	9	8	2.1	2.4	2.3	2.5	2.2	2.1	1.8	1.4	2.1	2.4	2.3	2.5	2.2	2.1	1.8	1.4	-
PG&E	7/18/05	8 hours	8-Day	9	8	2.7	2.9	2.6	2.6	2.5	2.4	2.1	2.7	2.7	2.9	2.6	2.6	2.5	2.5	2.2	2.7	-
PG&E	7/19/05	8 hours	3-Day	35	29	18.3	18.1	19.0	19.7	20.3	20.0	20.3	18.5	18.5	18.1	19.0	19.8	20.3	20.0	20.3	18.5	19.3
PG&E	7/19/05	8 hours	3-Day Coin	35	29	7.1	8.6	9.2	10.0	10.4	10.5	11.5	10.5	9.4	9.5	10.5	11.8	12.1	11.7	12.2	11.7	-
PG&E	7/19/05	8 hours	10-Day	35	29	6.8	8.1	7.6	8.0	8.5	8.6	9.6	10.3	8.4	8.4	8.6	9.6	9.8	9.9	10.5	11.3	-
PG&E	7/19/05	8 hours	10-Day Adj	35	29	4.5	5.3	5.3	6.0	6.2	6.5	7.0	7.2	6.2	6.3	6.5	7.6	7.7	7.9	8.0	8.2	-
PG&E	7/19/05	8 hours	8-Day	35	29	6.8	7.8	7.2	7.8	8.4	8.5	9.5	10.4	8.1	8.0	8.1	9.2	9.6	9.8	10.4	11.4	-
PG&E	7/20/05	8 hours	dbp_3day	22	17	14.6	14.3	14.0	13.9	14.4	12.9	9.3	10.1	14.6	14.3	14.0	13.9	14.4	12.9	9.3	10.1	12.9
PG&E	7/20/05	8 hours	dbp_3coin	22	17	3.4	3.9	5.6	6.7	7.5	6.4	4.3	4.7	5.0	4.8	6.2	7.4	7.8	7.0	4.4	4.7	-
PG&E	7/20/05	8 hours	dbp_10day	22	17	6.2	6.5	6.8	7.3	7.9	6.2	3.7	5.2	6.2	6.5	6.9	7.3	7.9	6.5	3.8	5.2	-
PG&E	7/20/05	8 hours	dbp_10dayad	22	17	6.7	7.1	7.8	8.2	8.9	6.9	4.4	5.3	6.8	7.2	7.8	8.2	8.9	6.9	4.7	5.8	-
PG&E	7/20/05	8 hours	dbp_8day	22	17	6.6	6.9	7.3	7.7	8.4	6.5	3.8	5.6	6.6	6.9	7.3	7.8	8.4	6.6	3.8	5.6	-

Exhibit D1-4b
Hourly Impact Estimates for PG&E DBP Participants – Summer 2005 Events
Events 8-17 (Bids Captured)

Utility	Event	Event Length	Baseline	N	n	Hourly DBP Impacts (in MW)																
						All Impacts								Positive Impacts								Utility Reported
						12-1	1-2	2-3	3-4	4-5	5-6	6-7	7-8	12-1	1-2	2-3	3-4	4-5	5-6	6-7	7-8	
PG&E	7/21/05	8 hours	3-Day	28	27	16.0	15.8	15.5	16.7	17.5	17.0	14.1	14.1	17.0	16.9	16.4	17.3	18.2	17.7	14.8	14.6	16.6
PG&E	7/21/05	8 hours	3-Day Coin	28	27	7.0	7.1	7.6	9.2	9.9	9.1	7.9	8.4	8.9	9.1	9.6	11.0	11.9	11.2	9.9	10.1	-
PG&E	7/21/05	8 hours	10-Day	28	27	6.1	6.1	5.9	7.2	7.8	7.4	6.2	7.4	8.1	8.3	8.1	9.1	9.9	9.4	8.2	9.2	-
PG&E	7/21/05	8 hours	10-Day Adj	28	27	4.3	4.1	4.2	5.6	6.0	5.5	4.8	5.5	5.6	5.6	5.7	6.9	7.4	6.9	6.0	6.5	-
PG&E	7/21/05	8 hours	8-Day	28	27	5.8	5.8	5.5	6.9	7.7	7.4	6.1	7.5	7.7	7.9	7.6	8.8	9.7	9.4	7.9	9.1	-
PG&E	7/22/05	8 hours	3-Day	39	38	37.7	37.1	38.7	36.9	34.8	31.5	24.2	22.5	38.6	37.8	39.4	37.7	35.4	32.3	27.2	26.4	34.4
PG&E	7/22/05	8 hours	3-Day Coin	39	38	17.3	16.8	17.9	17.0	17.2	14.8	11.7	10.9	19.2	18.6	20.3	19.6	19.8	18.0	17.7	17.5	-
PG&E	7/22/05	8 hours	10-Day	39	38	18.0	16.9	18.1	16.9	15.4	13.9	9.0	8.3	19.9	19.0	20.4	19.0	17.8	16.7	14.5	15.5	-
PG&E	7/22/05	8 hours	10-Day Adj	39	38	19.8	18.8	19.9	18.7	17.3	15.8	9.4	8.1	21.1	20.0	21.2	20.2	19.0	17.6	15.6	16.0	-
PG&E	7/22/05	8 hours	8-Day	39	38	18.2	17.0	18.1	16.9	15.3	13.8	8.9	8.4	20.0	19.2	20.4	19.0	17.7	16.5	14.6	15.8	-
PG&E	7/25/05	8 hours	3-Day	9	9	5.9	5.6	5.1	5.3	5.9	5.8	5.1	5.1	5.9	5.6	5.1	5.3	5.9	5.8	5.1	5.1	5.5
PG&E	7/25/05	8 hours	3-Day Coin	9	9	2.3	2.4	2.5	2.8	2.4	2.3	1.8	1.8	2.4	2.5	2.7	2.9	2.6	2.5	1.8	1.8	-
PG&E	7/25/05	8 hours	10-Day	9	9	2.0	1.9	1.9	2.1	2.0	1.9	1.6	2.3	2.1	2.0	1.9	2.2	2.1	2.0	1.6	2.3	-
PG&E	7/25/05	8 hours	10-Day Adj	9	9	1.2	1.3	1.4	1.6	1.4	1.2	0.8	1.1	1.3	1.5	1.6	1.8	1.6	1.4	0.8	1.1	-
PG&E	7/25/05	8 hours	8-Day	9	9	1.7	1.5	1.5	1.7	1.7	1.6	1.3	2.2	1.8	1.7	1.5	1.8	1.8	1.7	1.3	2.2	-
PG&E	7/26/05	8 hours	3-Day	36	35	27.5	27.9	28.5	28.0	27.2	23.3	21.7	23.2	28.3	28.5	29.1	28.6	28.0	24.0	22.5	23.8	26.6
PG&E	7/26/05	8 hours	3-Day Coin	36	35	13.8	13.0	13.4	13.4	14.0	10.5	11.6	14.5	15.5	14.6	15.2	15.3	16.2	12.5	13.6	16.5	-
PG&E	7/26/05	8 hours	10-Day	36	35	12.0	11.5	12.2	11.9	11.3	9.0	9.0	11.4	14.0	13.6	14.3	14.1	13.8	11.3	11.3	13.6	-
PG&E	7/26/05	8 hours	10-Day Adj	36	35	11.4	11.1	11.6	11.4	10.6	8.5	8.6	10.5	12.6	12.1	12.9	12.7	12.4	10.4	10.3	11.7	-
PG&E	7/26/05	8 hours	8-Day	36	35	11.6	11.1	11.4	11.2	10.6	8.5	8.5	11.1	13.6	13.0	13.4	13.3	13.1	10.8	10.8	13.2	-
PG&E	7/27/05	8 hours	3-Day	26	26	34.0	34.4	35.3	35.1	35.0	31.3	29.3	30.6	34.1	34.5	35.3	35.2	35.0	31.3	29.3	30.6	33.2
PG&E	7/27/05	8 hours	3-Day Coin	26	26	21.3	20.4	21.2	21.7	23.1	19.8	20.4	23.0	21.5	20.7	21.4	21.9	23.3	20.0	20.4	23.0	-
PG&E	7/27/05	8 hours	10-Day	26	26	19.9	19.4	20.6	20.7	20.7	18.5	18.3	20.3	20.2	19.7	20.6	20.8	20.9	18.6	18.3	20.3	-
PG&E	7/27/05	8 hours	10-Day Adj	26	26	18.1	17.4	18.2	18.3	18.2	16.2	15.9	17.3	18.3	17.9	18.6	18.7	18.5	16.5	16.4	17.9	-
PG&E	7/27/05	8 hours	8-Day	26	26	19.5	18.9	19.8	19.9	20.0	18.0	17.7	19.9	19.7	19.1	19.8	20.0	20.1	18.0	17.7	19.9	-
PG&E	7/29/05	8 hours	3-Day	37	35	33.3	35.0	36.3	36.7	37.1	32.9	33.6	27.3	33.4	35.1	36.4	36.9	37.4	33.0	33.6	27.3	34.1
PG&E	7/29/05	8 hours	3-Day Coin	37	35	10.9	12.7	15.2	17.6	19.1	18.3	21.1	16.6	13.9	15.6	17.5	19.0	19.7	18.7	21.1	17.4	-
PG&E	7/29/05	8 hours	10-Day	37	35	17.8	18.4	20.4	21.7	22.3	20.1	21.7	16.5	18.1	18.8	20.8	22.2	22.9	20.5	21.8	16.8	-
PG&E	7/29/05	8 hours	10-Day Adj	37	35	5.6	6.0	7.6	8.9	9.3	7.9	9.6	3.4	9.4	9.6	10.9	12.3	12.5	10.8	12.2	9.4	-
PG&E	7/29/05	8 hours	8-Day	37	35	18.6	19.1	20.9	22.3	22.8	20.6	21.8	16.4	18.8	19.4	21.3	22.7	23.4	20.9	21.9	16.7	-
PG&E	8/1/05	8 hours	3-Day	18	18	33.1	33.2	32.3	32.1	32.3	30.3	24.6	19.5	33.1	33.2	32.3	32.1	32.3	30.3	24.6	19.5	29.7
PG&E	8/1/05	8 hours	3-Day Coin	18	18	13.6	13.7	13.8	14.3	15.0	14.9	10.6	8.3	13.8	13.9	14.0	14.5	15.2	15.2	10.7	8.5	-
PG&E	8/1/05	8 hours	10-Day	18	18	18.3	17.6	17.1	17.0	17.5	16.8	12.5	8.7	18.4	17.8	17.2	17.1	17.6	16.9	12.6	8.8	-
PG&E	8/1/05	8 hours	10-Day Adj	18	18	8.7	8.3	7.9	7.9	8.5	8.1	3.7	-1.1	8.9	8.5	8.2	8.4	9.1	8.8	4.4	2.5	-
PG&E	8/1/05	8 hours	8-Day	18	18	18.3	17.6	16.9	16.8	17.5	16.8	12.4	8.3	18.4	17.7	17.0	16.9	17.6	16.9	12.4	8.3	-
PG&E	8/4/05	8 hours	3-Day	38	36	30.3	30.2	24.6	24.1	23.9	23.7	20.5	24.3	30.4	30.2	24.7	24.4	24.5	23.7	20.9	24.3	25.4
PG&E	8/4/05	8 hours	3-Day Coin	38	36	15.2	15.4	10.6	11.3	12.0	12.5	11.7	11.2	15.9	17.8	14.0	14.6	14.7	14.2	13.1	12.5	-
PG&E	8/4/05	8 hours	10-Day	38	36	14.7	14.8	10.0	10.5	10.9	10.7	8.3	9.8	14.9	16.5	12.5	12.7	12.6	12.0	9.4	10.6	-
PG&E	8/4/05	8 hours	10-Day Adj	38	36	10.7	11.0	6.2	6.9	7.4	7.4	4.5	5.0	10.9	11.3	6.9	7.6	8.1	8.1	7.2	9.0	-
PG&E	8/4/05	8 hours	8-Day	38	36	14.3	14.4	9.6	10.1	10.3	10.1	7.5	7.9	14.5	15.4	11.4	11.5	11.4	11.0	8.5	8.5	-
PG&E	8/5/05	8 hours	3-Day	35	34	27.9	27.2	28.3	28.5	27.8	25.9	18.9	22.5	28.1	27.3	28.3	28.5	27.8	25.9	18.9	22.5	25.9
PG&E	8/5/05	8 hours	3-Day Coin	35	34	14.4	14.7	16.5	17.4	16.9	15.7	11.0	10.6	14.9	14.9	16.6	17.5	17.1	16.0	11.2	10.9	-
PG&E	8/5/05	8 hours	10-Day	35	34	13.1	12.6	14.6	15.2	14.5	13.2	7.1	8.4	13.5	13.5	14.8	15.3	14.6	13.3	7.2	8.6	-
PG&E	8/5/05	8 hours	10-Day Adj	35	34	8.4	8.1	10.2	10.8	10.0	8.7	0.6	1.0	8.9	8.3	10.5	11.0	10.4	9.1	3.8	4.7	-
PG&E	8/5/05	8 hours	8-Day	35	34	12.0	11.5	13.4	13.9	13.3	12.2	6.2	6.4	12.4	12.4	13.5	14.0	13.4	12.3	6.3	6.6	-
PG&E	8/8/05	8 hours	3-Day	17	17	25.7	25.0	25.2	25.8	25.9	25.0	19.4	22.9	25.7	25.0	25.2	25.8	25.9	25.0	19.4	22.9	24.4
PG&E	8/8/05	8 hours	3-Day Coin	17	17	11.8	12.2	13.6	14.6	14.7	15.2	11.2	10.4	12.5	12.5	13.6	14.6	14.7	15.2	11.2	10.4	-
PG&E	8/8/05	8 hours	10-Day	17	17	11.4	11.5	12.5	13.4	13.4	13.1	8.0	9.3	11.6	11.5	12.5	13.4	13.4	13.1	8.0	9.3	-
PG&E	8/8/05	8 hours	10-Day Adj	17	17	4.4	4.5	5.6	6.6	6.6	6.5	0.7	1.0	5.4	5.3	5.9	6.9	7.0	6.8	3.7	4.5	-
PG&E	8/8/05	8 hours	8-Day	17	17	10.4	10.4	11.6	12.3	12.3	12.3	7.1	7.3	10.4	10.4	11.6	12.3	12.3	12.3	7.2	7.3	-

Exhibit D1-5
Hourly Impact Estimates for SCE DBP Participants – Summer 2005 Events

Utility	Event	Event Length	Baseline	N	n	Hourly DBP Impacts (in MW)																
						All Impacts								Positive Impacts								Utility Reported
						12-1	1-2	2-3	3-4	4-5	5-6	6-7	7-8	12-1	1-2	2-3	3-4	4-5	5-6	6-7	7-8	
SCE	7/13/05	8 hours	3-Day	21	21	12.7	12.7	4.2	2.9	3.2	3.2	2.7	3.4	12.7	12.7	5.0	3.9	3.5	3.4	3.1	3.8	na
SCE	7/13/05	8 hours	3-Day Coin	21	21	11.1	11.4	3.1	1.9	1.9	1.2	1.2	1.8	11.5	11.4	4.0	3.0	2.5	1.9	2.1	2.2	-
SCE	7/13/05	8 hours	10-Day	21	21	10.3	10.5	2.1	0.9	1.4	1.3	1.1	1.8	10.9	10.8	3.6	2.8	2.2	2.0	1.9	2.3	-
SCE	7/13/05	8 hours	10-Day Adj	21	21	11.8	12.1	3.7	2.5	1.8	1.6	1.4	1.8	12.5	12.3	3.9	2.9	2.3	2.0	1.9	2.3	-
SCE	7/13/05	8 hours	8-Day	21	21	10.2	10.4	2.0	0.8	1.4	1.3	1.0	1.7	10.8	10.7	3.6	2.8	2.2	1.9	1.8	2.2	-
SCE	7/14/05	8 hours	3-Day	30	29	5.9	5.4	4.9	4.9	3.3	2.5	0.8	2.0	6.7	6.2	5.8	5.6	4.1	3.9	2.5	2.8	na
SCE	7/14/05	8 hours	3-Day Coin	30	29	4.8	4.4	3.7	3.3	2.0	0.9	-0.8	0.1	5.4	4.9	4.5	3.9	2.8	1.8	1.6	1.5	-
SCE	7/14/05	8 hours	10-Day	30	29	3.2	3.1	2.2	2.2	0.8	0.0	-1.5	-0.1	4.6	4.4	4.1	3.7	2.4	2.1	1.6	1.5	-
SCE	7/14/05	8 hours	10-Day Adj	30	29	4.8	4.6	3.7	3.7	1.9	1.0	-0.6	1.3	5.5	5.2	4.9	4.6	2.9	2.7	1.8	2.1	-
SCE	7/14/05	8 hours	8-Day	30	29	3.6	3.5	2.5	2.4	1.0	0.2	-1.4	-0.1	4.7	4.5	4.2	3.7	2.5	2.0	1.5	1.4	-
SCE	7/19/05	8 hours	3-Day	32	32	12.3	11.3	10.5	11.5	10.2	9.1	10.9	11.3	14.7	14.0	12.8	13.4	12.0	11.3	13.2	13.0	15.7
SCE	7/19/05	8 hours	3-Day Coin	32	32	8.6	7.9	6.8	7.5	6.2	5.1	6.5	6.7	11.1	11.0	10.3	9.7	8.5	7.8	10.0	9.6	-
SCE	7/19/05	8 hours	10-Day	32	32	2.6	2.2	1.1	2.1	0.7	-0.2	0.5	1.3	7.2	7.5	6.6	6.5	5.2	4.7	5.8	5.5	-
SCE	7/19/05	8 hours	10-Day Adj	32	32	5.7	5.2	4.0	4.9	3.1	2.1	2.6	3.3	7.5	7.3	5.8	6.7	5.0	4.4	5.0	5.3	-
SCE	7/19/05	8 hours	8-Day	32	32	3.1	2.4	1.4	2.2	1.2	-0.2	0.4	0.8	7.4	7.6	6.6	6.3	5.5	4.5	5.5	4.9	-
SCE	7/20/05	8 hours	3-Day	37	37	14.4	14.6	14.7	16.4	9.5	6.9	7.4	8.0	19.1	19.4	18.9	20.7	13.3	9.9	9.9	10.2	8.7
SCE	7/20/05	8 hours	3-Day Coin	37	37	11.6	11.8	11.3	11.7	4.2	2.7	3.5	3.9	15.4	15.8	15.3	16.1	8.5	6.3	6.4	6.8	-
SCE	7/20/05	8 hours	10-Day	37	37	1.8	4.0	4.0	4.4	-3.3	-2.5	-1.5	-0.3	9.1	11.3	11.2	12.1	3.8	3.4	3.8	4.6	-
SCE	7/20/05	8 hours	10-Day Adj	37	37	4.6	6.6	6.6	7.2	-0.8	-0.9	0.1	0.9	9.5	11.0	10.9	11.9	3.4	2.6	3.2	3.9	-
SCE	7/20/05	8 hours	8-Day	37	37	2.4	4.5	4.4	4.6	-2.5	-2.4	-0.9	-0.1	9.4	11.5	11.3	11.9	4.0	3.2	4.1	4.6	-
SCE	7/21/05	8 hours	3-Day	42	42	7.4	7.2	8.0	8.5	5.0	2.9	5.5	6.8	10.7	10.2	10.8	11.2	7.8	5.5	8.0	9.0	12.3
SCE	7/21/05	8 hours	3-Day Coin	42	42	4.6	4.7	4.9	4.9	1.1	-1.6	1.2	2.6	7.0	7.0	7.0	7.0	3.1	1.8	4.3	5.2	-
SCE	7/21/05	8 hours	10-Day	42	42	-2.1	-1.9	-1.6	-1.1	-4.8	-6.7	-4.8	-3.5	3.2	3.5	3.4	3.8	1.8	1.6	2.6	2.9	-
SCE	7/21/05	8 hours	10-Day Adj	42	42	-0.7	-0.4	-0.1	0.3	-3.7	-6.0	-4.1	-3.0	3.4	3.6	3.6	4.2	3.3	3.2	4.0	4.4	-
SCE	7/21/05	8 hours	8-Day	42	42	-1.6	-1.6	-1.3	-1.0	-4.2	-6.7	-5.0	-4.3	3.3	3.5	3.2	3.4	1.6	1.4	1.6	1.8	-
SCE	7/22/05	8 hours	3-Day	37	37	0.4	4.9	4.0	4.1	4.5	4.9	6.6	7.5	3.8	8.4	6.3	6.2	6.7	7.0	8.5	9.1	13.0
SCE	7/22/05	8 hours	3-Day Coin	37	37	-2.1	2.6	1.4	0.9	0.8	0.8	3.1	4.0	2.8	6.2	4.0	4.1	4.1	3.7	5.5	5.9	-
SCE	7/22/05	8 hours	10-Day	37	37	-8.6	-3.8	-4.9	-4.7	-4.8	-4.3	-3.0	-1.9	2.1	3.0	2.9	2.9	3.0	2.8	3.4	3.3	-
SCE	7/22/05	8 hours	10-Day Adj	37	37	-7.2	-2.2	-3.2	-3.1	-3.5	-3.3	-1.9	-1.0	3.6	4.6	4.9	4.9	4.8	4.4	4.9	4.7	-
SCE	7/22/05	8 hours	8-Day	37	37	-7.7	-3.0	-4.2	-4.2	-3.8	-3.8	-2.7	-2.1	2.0	3.1	3.0	3.0	3.2	2.9	2.7	2.4	-
SCE	7/25/05	8 hours	3-Day	24	24	14.2	12.7	12.2	13.5	13.9	7.7	7.0	8.5	15.6	14.6	14.1	15.2	15.3	9.1	8.8	10.0	14.7
SCE	7/25/05	8 hours	3-Day Coin	24	24	12.0	10.9	10.3	11.2	11.2	4.7	4.5	4.7	12.6	12.8	12.3	13.1	12.8	6.6	6.3	6.4	-
SCE	7/25/05	8 hours	10-Day	24	24	6.6	5.8	5.2	6.7	6.6	0.4	0.1	2.1	9.1	9.6	8.9	10.2	9.8	3.8	3.9	5.1	-
SCE	7/25/05	8 hours	10-Day Adj	24	24	6.0	5.3	4.6	6.2	6.1	-0.1	0.1	2.6	7.7	8.4	7.7	9.0	8.7	2.8	2.9	5.2	-
SCE	7/25/05	8 hours	8-Day	24	24	7.7	6.7	6.0	7.3	7.7	1.0	2.1	3.7	9.2	9.5	8.8	9.9	10.0	3.6	4.6	6.0	-
SCE	7/26/05	8 hours	3-Day	36	36	4.1	3.9	4.1	3.9	3.7	4.4	4.0	5.1	4.4	5.0	5.2	4.8	4.5	4.7	4.8	6.2	6.6
SCE	7/26/05	8 hours	3-Day Coin	36	36	1.9	1.8	1.8	1.5	1.2	1.7	1.9	1.5	3.5	4.1	3.9	3.4	2.9	3.1	3.4	3.3	-
SCE	7/26/05	8 hours	10-Day	36	36	0.5	0.2	0.2	0.1	0.0	0.6	0.3	1.2	3.2	3.6	3.3	2.7	2.6	2.6	3.0	3.6	-
SCE	7/26/05	8 hours	10-Day Adj	36	36	2.9	2.6	2.5	2.3	1.8	2.5	2.6	4.1	4.6	5.0	4.8	4.4	3.9	4.2	4.5	6.3	-
SCE	7/26/05	8 hours	8-Day	36	36	0.7	0.5	0.4	0.3	0.2	0.7	1.2	2.0	3.2	3.7	3.5	2.9	2.7	2.7	3.3	4.4	-
SCE	7/27/05	8 hours	3-Day	38	38	13.3	12.7	12.0	12.2	11.4	10.5	4.6	8.2	15.1	14.5	13.4	13.7	13.1	12.1	6.1	9.5	10.9
SCE	7/27/05	8 hours	3-Day Coin	38	38	10.1	9.8	8.3	7.2	6.2	4.7	-0.8	1.5	12.0	12.2	11.1	10.2	9.1	7.2	2.8	4.1	-
SCE	7/27/05	8 hours	10-Day	38	38	1.0	2.5	1.8	0.9	-1.2	-1.9	-5.5	-1.0	8.8	10.6	10.1	8.8	7.1	5.6	2.6	3.2	-
SCE	7/27/05	8 hours	10-Day Adj	38	38	2.8	4.3	3.6	2.6	0.7	0.0	-3.1	1.9	10.9	12.5	12.0	10.8	9.0	7.6	3.8	5.5	-
SCE	7/27/05	8 hours	8-Day	38	38	2.5	3.9	2.9	1.7	0.3	-1.0	-2.9	0.7	8.8	10.9	10.3	8.9	7.2	5.6	2.9	3.9	-
SCE	7/29/05	8 hours	3-Day	44	45	15.3	19.7	16.2	15.6	12.5	8.8	5.7	5.8	15.5	19.9	16.3	15.6	12.6	9.1	8.2	9.0	22.3
SCE	7/29/05	8 hours	3-Day Coin	44	45	10.8	15.6	11.7	10.8	7.3	3.5	0.7	0.1	11.3	16.0	12.1	11.1	7.7	5.4	5.0	5.1	-
SCE	7/29/05	8 hours	10-Day	44	45	5.1	9.8	6.0	5.6	2.0	-1.7	-7.5	-7.4	6.6	11.4	7.6	7.0	5.0	4.1	3.7	4.0	-
SCE	7/29/05	8 hours	10-Day Adj	44	45	12.4	17.5	13.5	13.1	9.4	5.6	0.5	1.2	12.7	17.9	13.9	13.4	10.0	6.4	6.6	8.8	-
SCE	7/29/05	8 hours	8-Day	44	45	6.5	11.0	6.9	6.3	3.2	-1.1	-5.8	-6.5	7.6	12.2	8.1	7.3	5.5	4.3	4.2	4.8	-
SCE	8/4/05	8 hours	3-Day	39	39	23.6	20.9	20.8	21.9	21.7	20.8	16.1	12.8	23.7	21.2	21.0	22.4	21.8	20.9	16.5	13.4	14.5
SCE	8/4/05	8 hours	3-Day Coin	39	39	18.2	15.8	15.3	15.4	15.0	14.6	10.6	7.7	19.9	17.7	16.9	17.2	16.7	16.7	12.6	10.4	-
SCE	8/4/05	8 hours	10-Day	39	39	12.2	10.0	8.9	9.2	8.7	8.3	6.4	4.6	13.9	12.0	10.5	11.1	10.4	10.4	8.6	9.4	-
SCE	8/4/05	8 hours	10-Day Adj	39	39	2.9	0.4	-0.4	-0.3	-1.0	-1.4	-4.0	-5.8	8.0	5.7	5.0	4.9	4.6	4.0	5.4	6.6	-
SCE	8/4/05	8 hours	8-Day	39	39	13.3	11.3	9.8	10.0	9.8	8.8	7.1	5.5	14.6	12.8	11.1	11.6	11.2	10.4	8.7	9.4	-
SCE	8/5/05	8 hours	3-Day	40	40	22.4	24.5	25.4	26.1	25.3	23.7	7.6	7.7	22.7	24.6	25.5	26.3	25.6	23.9	7.8	7.9	15.6
SCE	8/5/05	8 hours	3-Day Coin	40	40	17.0	19.0	19.7	19.7	18.8	17.9	4.8	4.2	17.7	19.3	20.5	20.3	19.5	18.8	5.2	5.0	-
SCE	8/5/05	8 hours	10-Day	40	40	10.9	13.2	13.2	13.3	12.5	11.6	2.1	2.3	12.3	14.2	14.9	14.8	13.7	12.7	4.5	4.2	-
SCE	8/5/05	8 hours	10-Day Adj	40	40	1.5	3.6	3.9	3.8	2.9	1.8	4.0	4.6	9.1	11.5	12.7	12.5	11.5	10.1	5.5	5.3	-
SCE	8/5/05	8 hours	8-Day	40	40	12.0	14.4	14.1	14.0	13.6	12.0	3.2	3.0	12.8	15.0	15.3	15.1	14.3	12.9	4.6	4.3	-

Exhibit D1-6
Hourly Impact Estimates for SDG&E DBP Participants – Summer 2005 Events

Utility	Event	Baseline	N	n	Hourly DBP Impacts (in MW)										
					All Impacts					Positive Impacts					Utility Reported
					1-2	2-3	3-4	4-5	5-6	1-2	2-3	3-4	4-5	5-6	
SDG&E	7/12/05	3-Day	12	12	-	0.5	0.4	0.3	0.3	-	0.5	0.3	0.4	0.3	0.4
SDG&E	7/12/05	3-Day Coin	12	12	-	0.1	0.0	-0.2	-0.2	-	0.4	0.2	0.3	0.2	
SDG&E	7/12/05	10-Day	12	12	-	0.2	0.0	-0.1	-0.1	-	0.3	0.1	0.4	0.3	
SDG&E	7/12/05	10-Day Adj	12	12	-	0.3	0.2	0.0	0.0	-	0.4	0.1	0.3	0.2	
SDG&E	7/12/05	8-Day	12	12	-	0.2	0.0	-0.1	-0.1	-	0.3	0.1	1.4	1.5	
SDG&E	7/13/05	3-Day	13	13	-	1.4	1.4	1.3	1.3	-	1.4	1.3	1.3	1.4	1.3
SDG&E	7/13/05	3-Day Coin	13	13	-	1.2	1.2	1.1	1.2	-	1.3	1.3	1.1	1.1	
SDG&E	7/13/05	10-Day	13	13	-	1.0	1.0	0.9	0.9	-	1.1	1.0	1.3	1.3	
SDG&E	7/13/05	10-Day Adj	13	13	-	1.3	1.2	1.1	1.2	-	1.3	1.2	1.1	1.1	
SDG&E	7/13/05	8-Day	13	13	-	1.0	1.0	0.9	0.9	-	1.1	1.0	0.6	0.8	
SDG&E	7/14/05	3-Day	11	11	-	0.6	0.7	0.9	0.7	-	0.6	0.7	0.5	0.8	0.7
SDG&E	7/14/05	3-Day Coin	11	11	-	0.4	0.5	0.7	0.7	-	0.5	0.7	0.3	0.5	
SDG&E	7/14/05	10-Day	11	11	-	0.2	0.3	0.5	0.4	-	0.3	0.4	0.5	0.7	
SDG&E	7/14/05	10-Day Adj	11	11	-	0.4	0.6	0.7	0.6	-	0.5	0.7	0.3	0.5	
SDG&E	7/14/05	8-Day	11	11	-	0.2	0.3	0.5	0.4	-	0.3	0.4	0.9	0.9	
SDG&E	7/15/05	3-Day	11	11	-	0.9	0.8	0.8	-	-	0.9	0.9	0.8	-	0.8
SDG&E	7/15/05	3-Day Coin	11	11	-	0.7	0.6	0.7	-	-	0.9	0.6	0.6	-	
SDG&E	7/15/05	10-Day	11	11	-	0.5	0.4	0.5	-	-	0.6	0.9	0.8	-	
SDG&E	7/15/05	10-Day Adj	11	11	-	0.7	0.6	0.7	-	-	0.9	0.6	0.6	-	
SDG&E	7/15/05	8-Day	11	11	-	0.5	0.4	0.5	-	-	0.6	0.7	0.8	-	
SDG&E	7/19/05	3-Day	8	8	0.3	0.7	0.6	0.7	0.8	0.7	0.8	0.8	0.7	0.8	0.6
SDG&E	7/19/05	3-Day Coin	8	8	0.1	0.5	0.4	0.5	0.7	0.6	0.7	0.7	0.7	0.7	
SDG&E	7/19/05	10-Day	8	8	-0.2	0.3	0.3	0.4	0.5	0.4	0.5	0.5	0.5	0.5	
SDG&E	7/19/05	10-Day Adj	8	8	0.4	0.8	0.7	0.7	0.8	0.7	0.8	0.8	0.7	0.8	
SDG&E	7/19/05	8-Day	8	8	-0.2	0.4	0.4	0.4	0.5	0.4	0.5	0.5	0.5	0.5	
SDG&E	7/20/05	3-Day	8	8	-	0.0	0.2	0.3	-	-	0.1	0.2	0.3	-	0.2
SDG&E	7/20/05	3-Day Coin	8	8	-	-0.1	0.0	0.2	-	-	0.1	0.2	0.2	-	
SDG&E	7/20/05	10-Day	8	8	-	-0.1	0.1	0.2	-	-	0.1	0.1	0.2	-	
SDG&E	7/20/05	10-Day Adj	8	8	-	0.0	0.2	0.3	-	-	0.1	0.2	0.3	-	
SDG&E	7/20/05	8-Day	8	8	-	-0.1	0.1	0.2	-	-	0.1	0.1	0.2	-	
SDG&E	7/21/05	3-Day	6	6	-	-0.1	0.0	-0.1	-	-	0.0	0.1	0.1	-	0.0
SDG&E	7/21/05	3-Day Coin	6	6	-	-0.2	-0.1	-0.1	-	-	0.0	0.1	0.0	-	
SDG&E	7/21/05	10-Day	6	6	-	-0.2	-0.1	-0.2	-	-	0.0	0.1	0.0	-	
SDG&E	7/21/05	10-Day Adj	6	6	-	-0.2	-0.1	-0.1	-	-	0.0	0.0	0.0	-	
SDG&E	7/21/05	8-Day	6	6	-	-0.2	-0.1	-0.2	-	-	0.0	0.1	0.0	-	
SDG&E	7/22/05	3-Day	8	8	0.4	0.5	0.5	0.5	0.4	0.6	0.6	0.6	0.6	0.5	0.5
SDG&E	7/22/05	3-Day Coin	8	8	0.3	0.3	0.4	0.4	0.3	0.4	0.5	0.5	0.6	0.4	
SDG&E	7/22/05	10-Day	8	8	0.1	0.2	0.2	0.2	0.1	0.4	0.4	0.3	0.4	0.3	
SDG&E	7/22/05	10-Day Adj	8	8	0.4	0.4	0.4	0.5	0.4	0.5	0.6	0.5	0.6	0.5	
SDG&E	7/22/05	8-Day	8	8	0.1	0.2	0.2	0.3	0.1	0.4	0.4	0.3	0.4	0.3	
SDG&E	7/26/05	3-Day	7	7	-	-0.2	-0.2	-0.2	-	-	0.0	0.1	0.2	-	0.0
SDG&E	7/26/05	3-Day Coin	7	7	-	-0.3	-0.3	-0.3	-	-	0.0	0.1	0.1	-	
SDG&E	7/26/05	10-Day	7	7	-	-0.4	-0.3	-0.3	-	-	0.0	0.1	0.2	-	
SDG&E	7/26/05	10-Day Adj	7	7	-	-0.1	-0.1	-0.1	-	-	0.0	0.1	0.2	-	
SDG&E	7/26/05	8-Day	7	7	-	-0.4	-0.3	-0.3	-	-	0.0	0.1	0.2	-	
SDG&E	7/27/05	3-Day	7	7	-	1.8	1.7	-	-	-	1.8	1.9	-	-	1.8
SDG&E	7/27/05	3-Day Coin	7	7	-	1.3	1.2	-	-	-	1.3	1.4	-	-	
SDG&E	7/27/05	10-Day	7	7	-	1.2	1.0	-	-	-	1.5	1.3	-	-	
SDG&E	7/27/05	10-Day Adj	7	7	-	1.4	1.2	-	-	-	1.5	1.3	-	-	
SDG&E	7/27/05	8-Day	7	7	-	1.3	1.2	-	-	-	1.6	1.5	-	-	
SDG&E	8/4/05	3-Day	8	8	-	-	0.8	0.9	-	-	-	0.9	0.9	-	0.8
SDG&E	8/4/05	3-Day Coin	8	8	-	-	0.3	0.4	-	-	-	0.3	0.4	-	
SDG&E	8/4/05	10-Day	8	8	-	-	0.2	0.3	-	-	-	0.4	0.4	-	
SDG&E	8/4/05	10-Day Adj	8	8	-	-	0.1	0.2	-	-	-	0.3	0.3	-	
SDG&E	8/4/05	8-Day	8	8	-	-	0.2	0.3	-	-	-	0.4	0.4	-	
SDG&E	8/5/05	3-Day	4	4	-	0.5	0.5	0.5	-	-	0.5	0.5	0.5	-	0.4
SDG&E	8/5/05	3-Day Coin	4	4	-	0.1	0.2	0.1	-	-	0.2	0.2	0.2	-	
SDG&E	8/5/05	10-Day	4	4	-	0.2	0.2	0.2	-	-	0.2	0.2	0.2	-	
SDG&E	8/5/05	10-Day Adj	4	4	-	0.2	0.1	0.2	-	-	0.2	0.1	0.2	-	
SDG&E	8/5/05	8-Day	4	4	-	0.2	0.1	0.2	-	-	0.2	0.2	0.2	-	

D2. CPP and DBP Average Hourly Impact Tables

D2. CPP AND DBP AVERAGE HOURLY IMPACT TABLES

The CPP and DBP Average Hourly Impact Tables included in Appendix D2 contain the average hourly MW impact estimates across all event hours for each of the summer 2005 events, across the three utilities. Calculating the average hourly impact estimate for an individual event requires first calculating the sum of the estimated base load and the sum of the actual event day load across all event participants and all event hours. For the CPP program, event participants include all customers enrolled in the CPP program as of the day the event notification is sent out. For the DBP program, event participants include all DBP participants who placed a bid for the particular event. DBP participants who bid for only a fraction of the total event hours are included for only the hours they bid. Once these two sums have been calculated they are then divided by the event length to get the average hourly impact for the event[2].

The tables in this appendix include the hourly impact estimates from all six of the counting alternatives analyzed for this evaluation. This included counting all impacts (both positive and negative), counting only positive impacts (> 0 kW, >10 kW, > 5% of base load, and > 50kW) and counting all impacts beyond a tolerance threshold (+/- 5% of base load). Each of these alternatives is described in detail in Chapter 6.

The Exhibits in Appendix D2 include the following:

- D2-1 Average Hourly Impact Estimates for PG&E CPP Participants
- D2-2 Average Hourly Impact Estimates for SCE CPP Participants
- D2-3 Average Hourly Impact Estimates for SDG&E CPP Participants
- D2-4a/b/c Average Hourly Impact Estimates for PG&E DBP Participants
  - 4a includes events 1-7, for which the DBP bids were lost
  - 4b includes events 8-17, for which all bids were captured
  - 4c includes the average overall all 17 events
- D2-5 Average Hourly Impact Estimates for SCE DBP Participants
- D2-6 Average Hourly Impact Estimates for SDG&E DBP Participants

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[2] The event length used for the DBP program is equal to the average number of hours for which customers placed bids for the particular event.

Exhibit D2-1
Average Hourly Impact Estimates for PG&E CPP Participants – Summer 2005 Events
9 Events

Utility	Event	Event Length	Zone	Baseline	N	n	Estimated Load (MW)	Average Hourly Impacts (in MW)						Utility Reported	% Reduction
								All	Positive	>10kW	>5% Load	>50kW	+/- 5% Load		
PG&E	7/1/05	6 hours	2	3-Day	180	174	107.7	**17.3**	17.9	17.8	17.0	16.4	16.6	16.4	16.1%
PG&E	7/1/05	6 hours	2	3-Day Coin	180	174	103.1	**12.7**	14.0	13.9	13.2	12.5	12.0	-	12.3%
PG&E	7/1/05	6 hours	2	10-Day	180	174	99.2	**8.7**	11.4	11.3	10.9	10.4	8.6	-	8.8%
PG&E	7/1/05	6 hours	2	10-Day Adj	180	174	105.8	**15.4**	16.1	15.9	15.4	14.4	14.7	-	14.5%
PG&E	7/1/05	6 hours	2	8-Day	180	174	99.4	**9.0**	11.6	11.5	11.1	10.6	8.9	-	9.0%
PG&E	7/12/05	6 hours	2	3-Day	193	187	116.6	**9.5**	12.1	12.0	11.4	10.9	9.7	9.7	8.1%
PG&E	7/12/05	6 hours	2	3-Day Coin	193	187	110.7	**3.8**	9.0	8.8	8.3	7.9	4.0	-	3.4%
PG&E	7/12/05	6 hours	2	10-Day	193	187	106.0	**-1.2**	7.5	7.4	7.3	6.8	-0.7	-	-1.1%
PG&E	7/12/05	6 hours	2	10-Day Adj	193	187	112.6	**5.5**	8.7	8.6	8.0	7.8	5.6	-	4.9%
PG&E	7/12/05	6 hours	2	8-Day	193	187	106.2	**-0.9**	7.5	7.4	7.3	6.9	-0.5	-	-0.9%
PG&E	7/13/05	6 hours	1&2	3-Day	225	218	137.6	**9.8**	12.3	12.1	11.3	10.9	9.9	9.6	7.1%
PG&E	7/13/05	6 hours	1&2	3-Day Coin	225	218	131.3	**3.7**	9.0	8.8	8.1	7.7	3.9	-	2.8%
PG&E	7/13/05	6 hours	1&2	10-Day	225	218	125.8	**-2.0**	6.9	6.7	6.6	6.1	-1.4	-	-1.6%
PG&E	7/13/05	6 hours	1&2	10-Day Adj	225	218	133.5	**5.6**	9.0	8.8	8.2	7.7	5.5	-	4.2%
PG&E	7/13/05	6 hours	1&2	8-Day	225	218	126.0	**-1.8**	6.9	6.8	6.6	6.2	-1.1	-	-1.4%
PG&E	7/14/05	6 hours	2	3-Day	193	185	114.8	**11.2**	13.2	13.1	12.7	12.0	11.6	10.9	9.8%
PG&E	7/14/05	6 hours	2	3-Day Coin	193	185	109.4	**6.0**	9.7	9.6	9.1	8.6	6.4	-	5.5%
PG&E	7/14/05	6 hours	2	10-Day	193	185	104.4	**0.8**	8.0	7.9	7.9	7.5	1.3	-	0.8%
PG&E	7/14/05	6 hours	2	10-Day Adj	193	185	110.8	**7.3**	9.8	9.6	9.2	8.8	7.3	-	6.6%
PG&E	7/14/05	6 hours	2	8-Day	193	185	104.6	**1.0**	8.1	8.0	7.9	7.6	1.5	-	1.0%
PG&E	7/15/05	6 hours	2	3-Day	193	185	114.8	**11.8**	13.0	12.8	11.8	11.6	11.0	11.4	10.3%
PG&E	7/15/05	6 hours	2	3-Day Coin	193	185	109.4	**6.6**	9.5	9.3	8.4	8.2	5.8	-	6.0%
PG&E	7/15/05	6 hours	2	10-Day	193	185	104.4	**1.4**	6.9	6.8	6.5	6.0	2.0	-	1.4%
PG&E	7/15/05	6 hours	2	10-Day Adj	193	185	110.8	**7.9**	9.9	9.8	8.9	8.7	7.1	-	7.1%
PG&E	7/15/05	6 hours	2	8-Day	193	185	104.6	**1.6**	6.9	6.8	6.5	6.1	2.2	-	1.6%
PG&E	7/18/05	6 hours	2	3-Day	194	187	115.7	**11.4**	12.9	12.8	12.1	11.5	10.9	11.8	9.9%
PG&E	7/18/05	6 hours	2	3-Day Coin	194	187	110.3	**6.2**	9.4	9.3	8.5	8.1	5.7	-	5.6%
PG&E	7/18/05	6 hours	2	10-Day	194	187	105.3	**1.0**	6.8	6.7	6.5	6.0	1.7	-	0.9%
PG&E	7/18/05	6 hours	2	10-Day Adj	194	187	111.8	**7.5**	9.5	9.4	8.3	8.1	6.4	-	6.7%
PG&E	7/18/05	6 hours	2	8-Day	194	187	105.5	**1.2**	7.0	6.9	6.7	6.1	1.9	-	1.1%
PG&E	8/5/05	6 hours	2	3-Day	209	198	134.1	**10.4**	12.4	12.2	10.9	10.6	9.3	9.7	7.7%
PG&E	8/5/05	6 hours	2	3-Day Coin	209	198	126.5	**3.8**	7.5	7.3	6.4	6.3	3.3	-	3.0%
PG&E	8/5/05	6 hours	2	10-Day	209	198	125.3	**1.6**	7.0	6.8	6.5	6.0	2.1	-	1.3%
PG&E	8/5/05	6 hours	2	10-Day Adj	209	198	127.8	**4.1**	8.4	8.2	7.7	7.3	4.1	-	3.2%
PG&E	8/5/05	6 hours	2	8-Day	209	198	125.6	**1.9**	7.1	6.9	6.5	6.1	2.3	-	1.5%
PG&E	8/8/05	6 hours	2	3-Day	214	202	135.0	**12.5**	14.1	14.0	12.4	12.1	11.0	11.9	9.3%
PG&E	8/8/05	6 hours	2	3-Day Coin	214	202	128.3	**6.0**	9.1	9.0	7.6	7.4	4.7	-	4.7%
PG&E	8/8/05	6 hours	2	10-Day	214	202	126.2	**3.8**	8.1	7.9	7.0	6.8	3.1	-	3.0%
PG&E	8/8/05	6 hours	2	10-Day Adj	214	202	128.7	**6.3**	10.0	9.9	8.7	8.4	5.3	-	4.9%
PG&E	8/8/05	6 hours	2	8-Day	214	202	126.5	**4.0**	8.3	8.1	7.2	6.9	3.3	-	3.2%
PG&E	9/29/05	6 hours	1&2	3-Day	279	261	178.9	**6.7**	11.7	11.6	11.1	10.4	8.0	n/a	3.7%
PG&E	9/29/05	6 hours	1&2	3-Day Coin	279	261	171.0	**-1.2**	7.3	7.1	6.8	6.5	0.6	-	-0.7%
PG&E	9/29/05	6 hours	1&2	10-Day	279	261	165.0	**-7.2**	6.6	6.5	6.4	5.9	-6.3	-	-4.4%
PG&E	9/29/05	6 hours	1&2	10-Day Adj	279	261	175.8	**3.6**	9.5	9.4	8.6	8.1	4.3	-	2.0%
PG&E	9/29/05	6 hours	1&2	8-Day	279	261	165.5	**-6.7**	6.6	6.6	6.4	6.1	-5.8	-	-4.1%

PG&E CPP Events Summary - Aveage across Events

Program	Event Length	Zone	Baseline	N	n	Estimated Load (MW)	Average Hourly Impacts (in MW)						Utility Reported	% Reduction
							All	Positive	>10kW	>5% Load	>50kW	+/- 5% Load		
CPP	6 hours	1&2	3-Day	1,880	1,797	128.4	**11.2**	13.3	13.1	12.3	11.8	10.9	11.4	8.7%
CPP	6 hours	1&2	3-Day Coin	1,880	1,797	122.2	**5.3**	9.4	9.2	8.5	8.1	5.2	-	4.3%
CPP	6 hours	1&2	10-Day	1,880	1,797	118.0	**0.8**	7.7	7.6	7.3	6.8	1.1	-	0.6%
CPP	6 hours	1&2	10-Day Adj	1,880	1,797	124.2	**7.0**	10.1	10.0	9.2	8.8	6.7	-	5.6%
CPP	6 hours	1&2	8-Day	1,880	1,797	118.2	**1.0**	7.8	7.7	7.4	6.9	1.4	-	0.9%

Exhibit D2-2
Average Hourly Impact Estimates for SCE CPP Participants – Summer 2005 Events
12 Events

Utility	Event	Event Length	Baseline	N	n	Estimated Load (MW)	Average Hourly Impacts (in MW)						Utility Reported	% Reduction
							All	Positive	>10kW	>5% Load	>50kW	+/- 5% Load		
SCE	7/21/05	6 hours	3-Day	8	8	1.9	**0.9**	1.0	1.0	1.0	0.9	0.9	0.9	48.8%
SCE	7/21/05	6 hours	3-Day Coin	8	8	1.7	**0.7**	0.8	0.8	0.8	0.7	0.7	-	40.7%
SCE	7/21/05	6 hours	10-Day	8	8	1.5	**0.6**	0.7	0.7	0.7	0.7	0.6	-	36.6%
SCE	7/21/05	6 hours	10-Day Adj	8	8	1.5	**0.5**	0.7	0.7	0.7	0.6	0.5	-	34.3%
SCE	7/21/05	6 hours	8-Day	8	8	1.6	**0.6**	0.7	0.7	0.7	0.7	0.6	-	37.3%
SCE	7/22/05	6 hours	3-Day	8	8	1.9	**1.2**	1.2	1.2	1.2	1.2	1.2	1.2	62.5%
SCE	7/22/05	6 hours	3-Day Coin	8	8	1.7	**0.9**	1.0	1.0	1.0	0.9	0.9	-	56.6%
SCE	7/22/05	6 hours	10-Day	8	8	1.5	**0.8**	0.9	0.9	0.9	0.8	0.8	-	53.7%
SCE	7/22/05	6 hours	10-Day Adj	8	8	1.5	**0.8**	0.8	0.8	0.8	0.8	0.8	-	52.0%
SCE	7/22/05	6 hours	8-Day	8	8	1.6	**0.8**	0.9	0.9	0.9	0.8	0.8	-	54.1%
SCE	7/25/05	6 hours	3-Day	8	8	1.9	**1.0**	1.0	1.0	1.0	0.9	1.0	1.0	53.7%
SCE	7/25/05	6 hours	3-Day Coin	8	8	1.7	**0.8**	0.8	0.8	0.8	0.7	0.8	-	46.3%
SCE	7/25/05	6 hours	10-Day	8	8	1.5	**0.7**	0.7	0.7	0.7	0.6	0.7	-	42.7%
SCE	7/25/05	6 hours	10-Day Adj	8	8	1.5	**0.6**	0.7	0.6	0.7	0.6	0.6	-	40.6%
SCE	7/25/05	6 hours	8-Day	8	8	1.6	**0.7**	0.7	0.7	0.7	0.7	0.7	-	43.2%
SCE	8/26/05	6 hours	3-Day	8	8	1.9	**1.2**	1.2	1.2	1.2	1.1	1.2	1.2	63.7%
SCE	8/26/05	6 hours	3-Day Coin	8	8	1.8	**1.1**	1.1	1.1	1.1	1.1	1.1	-	61.6%
SCE	8/26/05	6 hours	10-Day	8	8	1.6	**0.9**	1.0	1.0	1.0	0.9	0.9	-	58.3%
SCE	8/26/05	6 hours	10-Day Adj	8	8	1.7	**1.0**	1.1	1.1	1.1	1.1	1.0	-	60.5%
SCE	8/26/05	6 hours	8-Day	8	8	1.6	**1.0**	1.0	1.0	1.0	1.0	1.0	-	58.7%
SCE	8/29/05	6 hours	3-Day	8	8	1.9	**1.0**	1.0	1.0	1.0	0.9	1.0	0.9	51.6%
SCE	8/29/05	6 hours	3-Day Coin	8	8	1.8	**0.9**	0.9	0.9	0.9	0.9	0.9	-	48.9%
SCE	8/29/05	6 hours	10-Day	8	8	1.6	**0.7**	0.8	0.8	0.8	0.8	0.7	-	44.5%
SCE	8/29/05	6 hours	10-Day Adj	8	8	1.7	**0.8**	0.9	0.9	0.9	0.9	0.8	-	47.4%
SCE	8/29/05	6 hours	8-Day	8	8	1.6	**0.7**	0.8	0.8	0.8	0.8	0.7	-	45.0%
SCE	8/30/05	6 hours	3-Day	8	8	1.9	**0.4**	0.5	0.5	0.5	0.4	0.4	0.4	22.2%
SCE	8/30/05	6 hours	3-Day Coin	8	8	1.8	**0.3**	0.4	0.4	0.4	0.3	0.3	-	17.9%
SCE	8/30/05	6 hours	10-Day	8	8	1.6	**0.2**	0.3	0.3	0.3	0.3	0.2	-	10.7%
SCE	8/30/05	6 hours	10-Day Adj	8	8	1.7	**0.3**	0.4	0.4	0.4	0.3	0.3	-	15.5%
SCE	8/30/05	6 hours	8-Day	8	8	1.6	**0.2**	0.3	0.3	0.3	0.3	0.2	-	11.6%
SCE	8/31/05	6 hours	3-Day	8	8	1.9	**1.0**	1.0	1.0	1.0	1.0	1.0	1.0	53.7%
SCE	8/31/05	6 hours	3-Day Coin	8	8	1.8	**0.9**	0.9	0.9	0.9	0.9	0.9	-	51.1%
SCE	8/31/05	6 hours	10-Day	8	8	1.6	**0.8**	0.8	0.8	0.8	0.8	0.8	-	46.8%
SCE	8/31/05	6 hours	10-Day Adj	8	8	1.7	**0.8**	0.9	0.9	0.9	0.9	0.8	-	49.6%
SCE	8/31/05	6 hours	8-Day	8	8	1.6	**0.8**	0.9	0.8	0.8	0.8	0.8	-	47.3%
SCE	9/15/05	6 hours	3-Day	8	8	1.8	**0.7**	0.8	0.8	0.8	0.7	0.7	0.7	37.1%
SCE	9/15/05	6 hours	3-Day Coin	8	8	1.7	**0.5**	0.7	0.7	0.7	0.7	0.5	-	32.7%
SCE	9/15/05	6 hours	10-Day	8	8	1.6	**0.4**	0.7	0.7	0.7	0.6	0.4	-	27.6%
SCE	9/15/05	6 hours	10-Day Adj	8	8	1.7	**0.5**	0.7	0.7	0.7	0.7	0.5	-	32.7%
SCE	9/15/05	6 hours	8-Day	8	8	1.6	**0.4**	0.7	0.7	0.7	0.6	0.4	-	28.3%
SCE	9/20/05	6 hours	3-Day	8	8	1.8	**1.0**	1.0	1.0	1.0	1.0	1.0	1.0	58.8%
SCE	9/20/05	6 hours	3-Day Coin	8	8	1.6	**0.9**	0.9	0.9	0.9	0.9	0.9	-	55.5%
SCE	9/20/05	6 hours	10-Day	8	8	1.5	**0.8**	0.9	0.9	0.9	0.9	0.8	-	52.3%
SCE	9/20/05	6 hours	10-Day Adj	8	8	1.6	**0.9**	0.9	0.9	0.9	0.9	0.9	-	55.3%
SCE	9/20/05	6 hours	8-Day	8	8	1.6	**0.8**	0.9	0.9	0.9	0.9	0.8	-	52.9%
SCE	9/22/05	6 hours	3-Day	8	8	1.8	**0.9**	1.0	1.0	1.0	1.0	1.0	0.9	53.4%
SCE	9/22/05	6 hours	3-Day Coin	8	8	1.6	**0.8**	0.9	0.9	0.9	0.8	0.8	-	49.7%
SCE	9/22/05	6 hours	10-Day	8	8	1.6	**0.7**	0.8	0.8	0.8	0.8	0.7	-	47.2%
SCE	9/22/05	6 hours	10-Day Adj	8	8	1.6	**0.8**	0.9	0.9	0.9	0.9	0.8	-	49.7%
SCE	9/22/05	6 hours	8-Day	8	8	1.6	**0.8**	0.8	0.8	0.8	0.8	0.8	-	47.8%
SCE	9/28/05	6 hours	3-Day	8	8	1.8	**0.9**	0.9	0.9	0.9	0.9	0.9	0.9	52.2%
SCE	9/28/05	6 hours	3-Day Coin	8	8	1.7	**0.8**	0.8	0.8	0.8	0.8	0.8	-	49.2%
SCE	9/28/05	6 hours	10-Day	8	8	1.6	**0.7**	0.8	0.8	0.8	0.8	0.7	-	45.7%
SCE	9/28/05	6 hours	10-Day Adj	8	8	1.6	**0.7**	0.8	0.8	0.8	0.7	0.7	-	46.4%
SCE	9/28/05	6 hours	8-Day	8	8	1.6	**0.7**	0.8	0.8	0.8	0.8	0.7	-	46.0%
SCE	9/29/05	6 hours	3-Day	8	8	1.8	**0.9**	1.0	1.0	1.0	1.0	1.0	0.9	53.5%
SCE	9/29/05	6 hours	3-Day Coin	8	8	1.7	**0.8**	0.9	0.9	0.9	0.9	0.8	-	50.5%
SCE	9/29/05	6 hours	10-Day	8	8	1.6	**0.7**	0.9	0.9	0.9	0.8	0.7	-	47.1%
SCE	9/29/05	6 hours	10-Day Adj	8	8	1.6	**0.8**	0.9	0.9	0.9	0.8	0.8	-	47.8%
SCE	9/29/05	6 hours	8-Day	8	8	1.6	**0.7**	0.9	0.9	0.9	0.9	0.7	-	47.4%

Exhibit D2-2 (con't)
Average Hourly Impact Estimates for SCE CPP Participants – Summer 2005 Events

SCE CPP Events Summary - Average across Events

Program	Event Length	Baseline	N	n	Estimated Load (MW)	Average Hourly Impacts (in MW)						Utility Reported	% Reduction
						All	Positive	>10kW	>5% Load	>50kW	+/- 5% Load		
CPP	6 hours	3-Day	96	96	1.8	**0.9**	1.0	1.0	1.0	0.9	0.9	0.9	50.9%
CPP	6 hours	3-Day Coin	96	96	1.7	**0.8**	0.8	0.8	0.8	0.8	0.8	-	46.7%
CPP	6 hours	10-Day	96	96	1.6	**0.7**	0.8	0.8	0.8	0.7	0.7	-	42.7%
CPP	6 hours	10-Day Adj	96	96	1.6	**0.7**	0.8	0.8	0.8	0.8	0.7	-	44.3%
CPP	6 hours	8-Day	96	96	1.6	**0.7**	0.8	0.8	0.8	0.7	0.7	-	43.3%

Exhibit D2-3
Average Hourly Impact Estimates for SDG&E CPP Participants – Summer 2005 Events
5 Events

Utility	Event	Event Length	Baseline	N	n	Estimated Load (MW)	Average Hourly Impacts (in MW)						Utility Reported	% Reduction
							All	Positive	>10kW	>5% Load	>50kW	+/- 5% Load		
SDG&E	7/21/05	7 hours	3-Day	87	85	**34.2**	**3.9**	5.8	5.8	5.7	5.5	4.0	4.0	11.3%
SDG&E	7/21/05	7 hours	3-Day Coin	87	85	31.7	**1.4**	4.1	4.1	4.0	3.9	1.5	-	4.3%
SDG&E	7/21/05	7 hours	10-Day	87	85	31.1	**0.7**	4.0	3.9	3.9	3.7	0.8	-	2.3%
SDG&E	7/21/05	7 hours	10-Day Adj	87	85	32.8	**2.4**	4.8	4.7	4.7	4.5	2.5	-	7.4%
SDG&E	7/21/05	7 hours	8-Day	87	85	31.0	**0.6**	3.8	3.8	3.7	3.6	0.7	-	2.0%
SDG&E	7/22/05	7 hours	3-Day	88	86	34.6	**4.2**	5.7	5.6	5.5	5.3	4.2	4.3	12.1%
SDG&E	7/22/05	7 hours	3-Day Coin	88	86	32.1	**1.7**	3.8	3.8	3.7	3.5	1.8	-	5.2%
SDG&E	7/22/05	7 hours	10-Day	88	86	31.4	**1.0**	3.5	3.4	3.4	3.2	1.2	-	3.2%
SDG&E	7/22/05	7 hours	10-Day Adj	88	86	33.1	**2.7**	4.3	4.2	4.1	3.8	2.7	-	8.2%
SDG&E	7/22/05	7 hours	8-Day	88	86	31.3	**0.9**	3.1	3.1	3.0	2.8	1.1	-	2.9%
SDG&E	8/26/05	7 hours	3-Day	110	102	43.0	**6.5**	7.9	7.8	7.7	7.5	6.4	6.5	15.1%
SDG&E	8/26/05	7 hours	3-Day Coin	110	102	40.0	**3.5**	5.6	5.5	5.4	5.3	3.5	-	8.7%
SDG&E	8/26/05	7 hours	10-Day	110	102	39.0	**2.5**	5.4	5.4	5.3	5.2	2.6	-	6.4%
SDG&E	8/26/05	7 hours	10-Day Adj	110	102	41.1	**4.6**	6.2	6.1	5.9	5.7	4.4	-	11.1%
SDG&E	8/26/05	7 hours	8-Day	110	102	38.8	**2.3**	5.4	5.3	5.2	5.1	2.4	-	6.0%
SDG&E	9/29/05	7 hours	3-Day	110	102	40.6	**5.5**	7.1	7.1	7.0	6.7	5.7	7.0	13.6%
SDG&E	9/29/05	7 hours	3-Day Coin	110	102	37.6	**2.5**	4.8	4.8	4.7	4.6	2.6	-	6.6%
SDG&E	9/29/05	7 hours	10-Day	110	102	36.6	**1.5**	4.4	4.3	4.3	4.2	1.6	-	4.0%
SDG&E	9/29/05	7 hours	10-Day Adj	110	102	38.7	**3.5**	5.4	5.4	5.3	5.2	3.7	-	9.2%
SDG&E	9/29/05	7 hours	8-Day	110	102	36.4	**1.3**	4.2	4.2	4.1	4.1	1.4	-	3.5%
SDG&E	9/30/05	7 hours	3-Day	110	102	40.6	**6.0**	6.9	6.9	6.6	6.4	5.9	7.0	14.7%
SDG&E	9/30/05	7 hours	3-Day Coin	110	102	37.6	**3.0**	4.7	4.6	4.4	4.3	3.0	-	7.8%
SDG&E	9/30/05	7 hours	10-Day	110	102	36.6	**1.9**	4.0	4.0	4.0	3.8	2.1	-	5.3%
SDG&E	9/30/05	7 hours	10-Day Adj	110	102	38.7	**4.0**	5.2	5.1	5.0	4.7	4.0	-	10.4%
SDG&E	9/30/05	7 hours	8-Day	110	102	36.4	**1.7**	3.6	3.6	3.5	3.4	1.9	-	4.8%

SDG&E CPP Events Summary - Average across Events

Program	Avg Length	Baseline	N	n	Estimated Load (MW)	Average Hourly Impacts (in MW)						Utility Reported	% Reduction
						All	Positive	>10kW	>5% Load	>50kW	+/- 5% Load		
CPP	7 hours	3-Day	505	477	**38.6**	**5.2**	6.7	6.6	6.5	6.3	5.2	5.8	13.5%
CPP	7 hours	3-Day Coin	505	477	**35.8**	**2.4**	4.6	4.6	4.5	4.3	2.5	-	6.7%
CPP	7 hours	10-Day	505	477	**34.9**	**1.5**	4.3	4.2	4.1	4.0	1.6	-	4.4%
CPP	7 hours	10-Day Adj	505	477	**36.9**	**3.5**	5.2	5.1	5.0	4.8	3.5	-	9.4%
CPP	7 hours	8-Day	505	477	**34.8**	**1.4**	4.0	4.0	3.9	3.8	1.5	-	4.0%

Exhibit D2-4a
Average Hourly Impact Estimates for PG&E DBP Participants – Summer 2005 Events
First 7 Events and Average over First 7 Events

Utility	Event	Event Length	Baseline	N	n	Avg Hourly Bid (MW)	Estimated Load (MW)	Average Hourly Impacts (in MW)						Utility Reported	% Reduction	% Hourly Bids Paid	Bid RR%
								All	Positive	>10kW	>5% Load	>50kW	+/- 5% Load				
PG&E	7/12/05	8 hours	3-Day	27	18	14.3	56.3	**13.4**	13.4	13.4	12.6	13.4	12.6	11.0	23.7%	100%	93%
PG&E	7/12/05	8 hours	3-Day Coin	27	18	14.3	48.7	**6.7**	7.6	7.6	7.4	7.6	7.1	-	13.8%	100%	47%
PG&E	7/12/05	8 hours	10-Day	27	18	14.3	48.2	**5.2**	6.2	6.2	6.1	6.1	5.8	-	10.9%	100%	37%
PG&E	7/12/05	8 hours	10-Day Adj	27	18	14.3	50.7	**7.8**	7.8	7.8	7.4	7.8	7.4	-	15.3%	100%	54%
PG&E	7/12/05	8 hours	8-Day	27	18	14.3	48.0	**5.0**	5.8	5.8	5.8	5.8	5.5	-	10.5%	100%	35%
PG&E	7/13/05	8 hours	3-Day	46	38	44.4	102.1	**45.1**	45.2	45.2	44.8	45.2	44.7	33.1	44.1%	100%	102%
PG&E	7/13/05	8 hours	3-Day Coin	46	38	44.4	83.9	**26.9**	28.3	28.3	28.1	28.2	27.0	-	32.0%	100%	61%
PG&E	7/13/05	8 hours	10-Day	46	38	44.4	83.0	**26.0**	27.4	27.4	27.3	27.3	26.0	-	31.3%	100%	59%
PG&E	7/13/05	8 hours	10-Day Adj	46	38	44.4	84.3	**27.3**	28.0	28.0	27.7	28.0	27.3	-	32.3%	100%	61%
PG&E	7/13/05	8 hours	8-Day	46	38	44.4	82.4	**25.4**	26.7	26.7	26.6	26.6	25.4	-	30.8%	100%	57%
PG&E	7/14/05	8 hours	3-Day	29	23	26.2	74.0	**25.5**	25.8	25.8	25.1	25.8	24.8	19.4	34.4%	100%	97%
PG&E	7/14/05	8 hours	3-Day Coin	29	23	26.2	60.8	**13.1**	15.3	15.3	15.2	15.3	13.6	-	21.6%	100%	50%
PG&E	7/14/05	8 hours	10-Day	29	23	26.2	61.5	**13.0**	15.6	15.6	15.6	15.6	13.6	-	21.1%	100%	50%
PG&E	7/14/05	8 hours	10-Day Adj	29	23	26.2	61.1	**12.6**	13.2	13.2	13.0	13.1	12.6	-	20.6%	100%	48%
PG&E	7/14/05	8 hours	8-Day	29	23	26.2	61.4	**12.9**	15.5	15.5	15.4	15.4	13.5	-	21.0%	100%	49%
PG&E	7/15/05	8 hours	3-Day	38	33	21.9	75.4	**20.9**	21.2	21.2	20.2	21.1	20.0	16.3	27.8%	100%	95%
PG&E	7/15/05	8 hours	3-Day Coin	38	33	21.9	64.5	**11.2**	12.5	12.5	12.0	12.5	11.1	-	17.4%	100%	51%
PG&E	7/15/05	8 hours	10-Day	38	33	21.9	64.1	**9.6**	11.5	11.5	11.3	11.4	10.1	-	15.0%	100%	44%
PG&E	7/15/05	8 hours	10-Day Adj	38	33	21.9	65.4	**10.9**	11.3	11.3	10.8	11.1	10.6	-	16.7%	100%	50%
PG&E	7/15/05	8 hours	8-Day	38	33	21.9	63.9	**9.4**	11.3	11.3	11.0	11.2	9.8	-	14.8%	100%	43%
PG&E	7/18/05	8 hours	3-Day	9	8	7.1	10.6	**7.1**	7.1	7.1	7.0	7.1	7.0	6.4	66.7%	100%	100%
PG&E	7/18/05	8 hours	3-Day Coin	9	8	7.1	7.2	**3.7**	3.7	3.7	3.6	3.7	3.6	-	50.9%	100%	52%
PG&E	7/18/05	8 hours	10-Day	9	8	7.1	6.6	**3.1**	3.1	3.1	3.1	3.1	3.1	-	46.5%	100%	43%
PG&E	7/18/05	8 hours	10-Day Adj	9	8	7.1	5.8	**2.3**	2.3	2.3	2.3	2.3	2.3	-	39.5%	100%	33%
PG&E	7/18/05	8 hours	8-Day	9	8	7.1	6.3	**2.8**	2.8	2.8	2.8	2.8	2.8	-	44.3%	100%	40%
PG&E	7/19/05	8 hours	3-Day	35	29	20.2	83.8	**25.1**	25.2	25.2	24.8	25.2	24.8	15.4	30.0%	100%	124%
PG&E	7/19/05	8 hours	3-Day Coin	35	29	20.2	71.4	**12.7**	14.5	14.5	14.2	14.5	12.5	-	17.8%	100%	63%
PG&E	7/19/05	8 hours	10-Day	35	29	20.2	69.7	**11.0**	12.5	12.4	12.3	12.3	11.0	-	15.8%	100%	54%
PG&E	7/19/05	8 hours	10-Day Adj	35	29	20.2	66.5	**7.8**	9.5	9.5	9.2	9.4	8.0	-	11.7%	100%	39%
PG&E	7/19/05	8 hours	8-Day	35	29	20.2	69.5	**10.8**	12.2	12.2	12.0	12.0	10.8	-	15.5%	100%	54%
PG&E	7/20/05	8 hours	3-Day	22	17	16.4	40.3	**16.5**	16.5	16.5	16.4	16.4	16.4	13.0	40.9%	100%	100%
PG&E	7/20/05	8 hours	3-Day Coin	22	17	16.4	30.6	**6.8**	7.5	7.5	7.4	7.5	6.7	-	22.1%	100%	41%
PG&E	7/20/05	8 hours	10-Day	22	17	16.4	31.7	**7.9**	8.0	8.0	7.9	7.9	7.8	-	24.9%	100%	48%
PG&E	7/20/05	8 hours	10-Day Adj	22	17	16.4	32.6	**8.8**	8.9	8.9	8.9	8.9	8.7	-	26.9%	100%	54%
PG&E	7/20/05	8 hours	8-Day	22	17	16.4	32.2	**8.4**	8.4	8.4	8.3	8.4	8.3	-	26.1%	100%	51%

PG&E DBP Events Summary - Average across Events

	Baseline	N	n	Avg Hourly Bid (MW)	Estimated Load (MW)	Average Hourly Impacts (in MW)						Utility Reported	% Reduction	% Hourly Bids Paid	Bid RR%
						All	Positive	>10kW	>5% Load	>50kW	+/- 5% Load				
Average across first 7 events	3-Day	206	166	21.5	63.2	**21.9**	22.1	22.1	21.6	22.0	21.5	16.4	34.7%	100%	102%
	3-Day Coin	206	166	21.5	52.4	**11.6**	12.8	12.8	12.6	12.7	11.7	-	22.1%	100%	54%
	10-Day	206	166	21.5	52.1	**10.8**	12.0	12.0	11.9	12.0	11.1	-	20.8%	100%	50%
	10-Day Adj	206	166	21.5	52.3	**11.1**	11.6	11.6	11.3	11.5	11.0	-	21.1%	100%	51%
	8-Day	206	166	21.5	52.0	**10.7**	11.8	11.8	11.7	11.7	10.9	-	20.6%	100%	50%

Exhibit D2-4b
Average Hourly Impact Estimates for PG&E DBP Participants – Summer 2005 Events
Last 10 Events and Average over Last 10 Events

Utility	Event	Event Length	Baseline	N	n	Avg Hourly Bid (MW)	Estimated Load (MW)	Average Hourly Impacts (in MW)						Utility Reported	% Reduction	% Hourly Bids Paid	Bid RR%
								All	Positive	>10kW	>5% Load	>50kW	+/- 5% Load				
PG&E	7/21/05	8 hours	3-Day	28	27	16.6	64.4	**21.1**	22.1	22.1	21.8	22.1	21.1	14.7	32.8%	75%	127%
PG&E	7/21/05	8 hours	3-Day Coin	28	27	16.6	54.2	**11.0**	13.6	13.6	13.4	13.6	10.9	-	20.4%	75%	66%
PG&E	7/21/05	8 hours	10-Day	28	27	16.6	52.3	**9.0**	11.7	11.7	11.6	11.6	8.9	-	17.2%	75%	54%
PG&E	7/21/05	8 hours	10-Day Adj	28	27	16.6	50.0	**6.7**	8.4	8.4	8.2	8.4	6.5	-	13.3%	75%	40%
PG&E	7/21/05	8 hours	8-Day	28	27	16.6	52.1	**8.8**	11.4	11.3	11.2	11.2	8.7	-	16.8%	75%	53%
PG&E	7/22/05	8 hours	3-Day	39	38	38.6	103.3	**38.7**	40.3	40.3	40.2	40.3	39.1	29.7	37.4%	80%	100%
PG&E	7/22/05	8 hours	3-Day Coin	39	38	38.6	82.6	**18.1**	22.1	22.1	21.8	22.1	18.0	-	21.9%	80%	47%
PG&E	7/22/05	8 hours	10-Day	39	38	38.6	81.7	**17.1**	20.9	20.9	20.8	20.8	17.1	-	20.9%	80%	44%
PG&E	7/22/05	8 hours	10-Day Adj	39	38	38.6	83.3	**18.7**	22.1	22.1	22.0	22.0	18.7	-	22.5%	80%	49%
PG&E	7/22/05	8 hours	8-Day	39	38	38.6	81.7	**17.1**	21.0	21.0	20.9	20.9	17.1	-	20.9%	80%	44%
PG&E	7/25/05	8 hours	3-Day	9	9	6.0	11.9	**7.3**	7.3	7.3	7.3	0.1	7.3	5.5	61.5%	72%	121%
PG&E	7/25/05	8 hours	3-Day Coin	9	9	6.0	7.6	**3.0**	3.2	3.2	3.1	3.2	3.0	-	39.9%	72%	50%
PG&E	7/25/05	8 hours	10-Day	9	9	6.0	7.2	**2.6**	2.7	2.7	2.7	2.7	2.6	-	36.4%	72%	43%
PG&E	7/25/05	8 hours	10-Day Adj	9	9	6.0	6.2	**1.7**	1.8	1.8	1.8	1.8	1.7	-	26.7%	72%	28%
PG&E	7/25/05	8 hours	8-Day	9	9	6.0	6.8	**2.2**	2.3	2.3	2.2	2.3	2.2	-	32.6%	72%	37%
PG&E	7/26/05	8 hours	3-Day	36	35	31.1	90.8	**31.2**	32.0	32.0	31.8	31.8	31.8	18.8	34.3%	74%	100%
PG&E	7/26/05	8 hours	3-Day Coin	36	35	31.1	75.3	**15.6**	17.9	17.9	17.7	17.7	15.5	-	20.8%	74%	50%
PG&E	7/26/05	8 hours	10-Day	36	35	31.1	72.9	**13.3**	15.9	15.9	15.8	15.8	13.3	-	18.2%	74%	43%
PG&E	7/26/05	8 hours	10-Day Adj	36	35	31.1	72.2	**12.6**	14.3	14.3	14.1	14.1	12.5	-	17.4%	74%	40%
PG&E	7/26/05	8 hours	8-Day	36	35	31.1	72.3	**12.6**	15.2	15.2	15.1	15.1	12.6	-	17.4%	74%	41%
PG&E	7/27/05	8 hours	3-Day	26	26	30.2	59.0	**39.6**	39.6	39.6	39.5	39.6	39.5	25.6	67.1%	78%	131%
PG&E	7/27/05	8 hours	3-Day Coin	26	26	30.2	44.8	**25.5**	25.7	25.7	25.6	25.7	25.4	-	57.0%	78%	85%
PG&E	7/27/05	8 hours	10-Day	26	26	30.2	43.1	**23.7**	23.8	23.8	23.8	23.8	23.7	-	55.0%	78%	78%
PG&E	7/27/05	8 hours	10-Day Adj	26	26	30.2	40.3	**20.9**	21.3	21.3	21.2	21.3	20.7	-	51.9%	78%	69%
PG&E	7/27/05	8 hours	8-Day	26	26	30.2	42.3	**23.0**	23.1	23.1	23.0	23.0	23.0	-	54.2%	78%	76%
PG&E	7/29/05	8 hours	3-Day	37	35	35.5	81.2	**41.4**	41.6	41.6	41.3	41.5	41.2	30.8	51.0%	85%	117%
PG&E	7/29/05	8 hours	3-Day Coin	37	35	35.5	59.8	**20.0**	21.7	21.7	21.5	21.7	19.8	-	33.5%	85%	56%
PG&E	7/29/05	8 hours	10-Day	37	35	35.5	64.0	**24.2**	24.6	24.6	24.5	24.6	24.2	-	37.8%	85%	68%
PG&E	7/29/05	8 hours	10-Day Adj	37	35	35.5	48.6	**8.9**	13.3	13.3	13.1	13.2	8.8	-	18.2%	85%	25%
PG&E	7/29/05	8 hours	8-Day	37	35	35.5	64.5	**24.7**	25.1	25.1	25.1	25.1	24.8	-	38.3%	85%	70%
PG&E	8/1/05	8 hours	3-Day	18	18	27.7	42.9	**31.4**	31.4	31.4	31.4	31.4	31.4	22.1	73.2%	79%	113%
PG&E	8/1/05	8 hours	3-Day Coin	18	18	27.7	25.3	**13.8**	14.0	14.0	13.9	14.0	13.8	-	54.5%	79%	50%
PG&E	8/1/05	8 hours	10-Day	18	18	27.7	28.1	**16.6**	16.7	16.7	16.7	16.7	16.6	-	59.1%	79%	60%
PG&E	8/1/05	8 hours	10-Day Adj	18	18	27.7	18.4	**6.9**	7.8	7.8	7.7	7.7	6.9	-	37.4%	79%	25%
PG&E	8/1/05	8 hours	8-Day	18	18	27.7	28.0	**16.5**	16.6	16.6	16.6	16.6	16.5	-	58.9%	79%	59%
PG&E	8/4/05	8 hours	3-Day	38	36	35.5	77.2	**30.0**	30.2	30.2	29.9	30.1	29.9	22.4	38.8%	73%	84%
PG&E	8/4/05	8 hours	3-Day Coin	38	36	35.5	62.0	**14.9**	17.4	17.4	17.1	17.3	14.6	-	24.0%	73%	42%
PG&E	8/4/05	8 hours	10-Day	38	36	35.5	60.6	**13.4**	15.1	15.0	15.0	15.0	13.5	-	22.1%	73%	38%
PG&E	8/4/05	8 hours	10-Day Adj	38	36	35.5	56.0	**8.8**	10.3	10.3	10.1	10.2	8.7	-	15.7%	73%	25%
PG&E	8/4/05	8 hours	8-Day	38	36	35.5	59.8	**12.5**	13.7	13.7	13.7	13.7	12.8	-	21.0%	73%	35%
PG&E	8/5/05	8 hours	3-Day	35	34	31.0	54.3	**30.1**	30.1	30.1	30.1	30.0	30.1	24.2	55.4%	79%	97%
PG&E	8/5/05	8 hours	3-Day Coin	35	34	31.0	40.9	**17.0**	17.3	17.3	17.2	17.2	17.0	-	41.7%	79%	55%
PG&E	8/5/05	8 hours	10-Day	35	34	31.0	38.6	**14.4**	14.6	14.6	14.6	14.5	14.3	-	37.2%	79%	46%
PG&E	8/5/05	8 hours	10-Day Adj	35	34	31.0	32.6	**8.4**	9.7	9.7	9.5	9.5	8.4	-	25.8%	79%	27%
PG&E	8/5/05	8 hours	8-Day	35	34	31.0	37.1	**12.9**	13.2	13.2	13.1	13.2	12.9	-	34.8%	79%	42%
PG&E	8/8/05	8 hours	3-Day	17	17	27.1	44.9	**26.7**	26.7	26.7	26.7	26.7	26.7	20.7	59.5%	77%	99%
PG&E	8/8/05	8 hours	3-Day Coin	17	17	27.1	32.4	**14.2**	14.4	14.4	14.2	14.3	14.2	-	43.9%	77%	52%
PG&E	8/8/05	8 hours	10-Day	17	17	27.1	30.9	**12.7**	12.7	12.7	12.6	12.7	12.6	-	41.0%	77%	47%
PG&E	8/8/05	8 hours	10-Day Adj	17	17	27.1	23.1	**4.9**	6.2	6.2	6.2	6.2	4.9	-	21.3%	77%	18%
PG&E	8/8/05	8 hours	8-Day	17	17	27.1	29.7	**11.5**	11.5	11.5	11.4	11.5	11.4	-	38.7%	77%	42%

	Baseline	N	n	Avg Hourly Bid (MW)	Estimated Load (MW)	Average Hourly Impacts (in MW)						Utility Reported	% Reduction	% Hourly Bids Paid	Bid RR%
						All	Positive	>10kW	>5% Load	>50kW	+/- 5% Load				
Average across last 10 events	3-Day	283	275	27.9	63.0	**29.7**	30.1	30.1	30.0	29.4	29.8	21.5	47.2%	77%	106%
	3-Day Coin	283	275	27.9	48.5	**15.3**	16.7	16.7	16.6	16.7	15.2	-	31.6%	77%	55%
	10-Day	283	275	27.9	47.9	**14.7**	15.9	15.9	15.8	15.8	14.7	-	30.6%	77%	53%
	10-Day Adj	283	275	27.9	43.1	**9.8**	11.5	11.5	11.4	11.4	9.8	-	22.8%	77%	35%
	8-Day	283	275	27.9	47.4	**14.2**	15.3	15.3	15.2	15.2	14.2	-	29.9%	77%	51%

Exhibit D2-4c
Average Hourly Impact Estimates for PG&E DBP Participants – Summer 2005 Events
Average over All 17 Events

Program	Event Length	Baseline	N	n	Avg Hourly Bid (MW)	Estimated Load (MW)	Average Hourly Impacts (in MW)						Utility Reported	% Reduction	% Hourly Bids Paid	Bid RR%
							All	Positive	>10kW	>5% Load	>50kW	+/- 5% Load				
DBP	8 hours	3-Day	489	441	25.3	63.1	26.5	26.8	26.8	26.5	26.3	26.4	19.4	42.1%	87%	105%
DBP	8 hours	3-Day Coin	489	441	25.3	50.1	13.8	15.1	15.1	14.9	15.1	13.7	-	27.5%	87%	54%
DBP	8 hours	10-Day	489	441	25.3	49.7	13.1	14.3	14.3	14.2	14.2	13.2	-	26.4%	87%	52%
DBP	8 hours	10-Day Adj	489	441	25.3	46.9	10.3	11.5	11.5	11.4	11.5	10.3	-	22.1%	87%	41%
DBP	8 hours	8-Day	489	441	25.3	49.3	12.7	13.9	13.9	13.8	13.8	12.8	-	25.8%	87%	50%

Exhibit D2-5
Average Hourly Impact Estimates for SCE DBP Participants – Summer 2005 Events
12 Events

Utility	Event	Event Length	Baseline	N	n	Avg Hourly Bid (MW)	Estimated Load (MW)	Average Hourly Impacts (in MW)						Utility Reported	% Reduction	% Hourly Bids Paid	Bid RR%
								All	Positive	>10kW	>5% Load	>50kW	+/- 5% Load				
SCE	7/13/05	8 hours	3-Day	21	21	11.9	20.8	**6.8**	7.2	7.2	7.2	7.2	6.8	na	32.8%	29%	57%
SCE	7/13/05	8 hours	3-Day Coin	21	21	11.9	19.0	**5.1**	5.8	5.8	5.8	5.8	5.1	-	26.7%	29%	43%
SCE	7/13/05	8 hours	10-Day	21	21	11.9	18.4	**4.4**	5.5	5.5	5.5	5.5	4.5	-	24.2%	29%	37%
SCE	7/13/05	8 hours	10-Day Adj	21	21	11.9	19.5	**5.5**	6.0	6.0	6.0	6.0	5.6	-	28.4%	29%	47%
SCE	7/13/05	8 hours	8-Day	21	21	11.9	18.3	**4.3**	5.4	5.4	5.4	5.4	4.4	-	23.6%	29%	36%
SCE	7/14/05	8 hours	3-Day	30	29	7.0	59.5	**3.9**	5.0	5.0	4.7	4.9	4.2	na	6.6%	14%	56%
SCE	7/14/05	8 hours	3-Day Coin	30	29	7.0	40.4	**2.5**	3.5	3.5	3.3	3.5	2.5	-	6.1%	14%	35%
SCE	7/14/05	8 hours	10-Day	30	29	7.0	56.9	**1.3**	3.2	3.2	3.1	3.1	2.1	-	2.3%	14%	19%
SCE	7/14/05	8 hours	10-Day Adj	30	29	7.0	58.3	**2.8**	3.9	3.9	3.5	3.8	2.6	-	4.7%	14%	39%
SCE	7/14/05	8 hours	8-Day	30	29	7.0	57.1	**1.6**	3.2	3.1	3.0	3.1	2.2	-	2.8%	14%	23%
SCE	7/19/05	8 hours	3-Day	32	32	15.7	94.5	**12.0**	14.4	14.4	14.3	14.3	13.2	15.72	12.7%	29%	76%
SCE	7/19/05	8 hours	3-Day Coin	32	32	15.7	70.3	**7.6**	10.7	10.7	10.7	10.6	7.9	-	10.9%	29%	49%
SCE	7/19/05	8 hours	10-Day	32	32	15.7	83.9	**1.4**	6.8	6.7	6.7	6.7	1.6	-	1.7%	29%	9%
SCE	7/19/05	8 hours	10-Day Adj	32	32	15.7	86.7	**4.3**	6.5	6.5	6.1	6.4	4.8	-	4.9%	29%	27%
SCE	7/19/05	8 hours	8-Day	32	32	15.7	85.0	**2.5**	6.8	6.8	6.8	6.7	3.3	-	3.0%	29%	16%
SCE	7/20/05	8 hours	3-Day	37	37	20.7	109.2	**12.7**	16.8	16.7	16.7	16.7	13.3	8.70	11.6%	36%	61%
SCE	7/20/05	8 hours	3-Day Coin	37	37	20.7	83.1	**8.4**	12.5	12.5	12.5	12.4	8.7	-	10.1%	36%	40%
SCE	7/20/05	8 hours	10-Day	37	37	20.7	97.4	**0.9**	8.2	8.2	8.0	8.1	0.8	-	0.9%	36%	4%
SCE	7/20/05	8 hours	10-Day Adj	37	37	20.7	99.9	**3.4**	7.8	7.8	7.6	7.6	3.9	-	3.4%	36%	16%
SCE	7/20/05	8 hours	8-Day	37	37	20.7	98.5	**2.0**	7.8	7.8	7.7	7.7	2.5	-	2.0%	36%	10%
SCE	7/21/05	8 hours	3-Day	42	42	11.1	94.4	**7.0**	10.0	10.0	9.6	9.9	7.1	12.33	7.4%	34%	63%
SCE	7/21/05	8 hours	3-Day Coin	42	42	11.1	68.0	**3.1**	5.8	5.8	5.5	5.7	3.2	-	4.5%	34%	28%
SCE	7/21/05	8 hours	10-Day	42	42	11.1	83.8	**-3.6**	3.1	3.1	2.9	3.0	-3.5	-	-4.3%	34%	-33%
SCE	7/21/05	8 hours	10-Day Adj	42	42	11.1	85.0	**-2.4**	4.1	4.0	3.9	3.9	-2.2	-	-2.8%	34%	-22%
SCE	7/21/05	8 hours	8-Day	42	42	11.1	85.8	**-1.6**	2.9	2.9	2.4	2.8	-1.5	-	-1.9%	34%	-15%
SCE	7/22/05	8 hours	3-Day	37	37	13.0	123.9	**5.8**	8.8	8.8	8.0	8.7	6.8	13.00	4.7%	45%	44%
SCE	7/22/05	8 hours	3-Day Coin	37	37	13.0	95.6	**1.8**	5.7	5.7	5.5	5.6	2.9	-	1.9%	45%	14%
SCE	7/22/05	8 hours	10-Day	37	37	13.0	112.5	**-5.6**	3.7	3.7	3.6	3.6	-4.7	-	-5.0%	45%	-43%
SCE	7/22/05	8 hours	10-Day Adj	37	37	13.0	114.1	**-4.0**	5.8	5.7	5.5	5.6	-3.2	-	-3.5%	45%	-31%
SCE	7/22/05	8 hours	8-Day	37	37	13.0	115.6	**-2.5**	4.2	4.2	3.9	4.0	-1.4	-	-2.2%	45%	-20%
SCE	7/25/05	8 hours	3-Day	24	24	9.9	71.4	**13.3**	15.2	15.2	15.2	15.1	14.5	14.74	18.6%	36%	134%
SCE	7/25/05	8 hours	3-Day Coin	24	24	9.9	45.0	**10.3**	12.3	12.3	12.3	12.2	10.5	-	22.9%	36%	104%
SCE	7/25/05	8 hours	10-Day	24	24	9.9	63.1	**5.0**	8.9	8.9	8.9	8.9	5.3	-	7.9%	36%	50%
SCE	7/25/05	8 hours	10-Day Adj	24	24	9.9	62.7	**4.6**	7.8	7.8	7.7	7.6	5.1	-	7.3%	36%	46%
SCE	7/25/05	8 hours	8-Day	24	24	9.9	65.7	**7.6**	9.5	9.5	9.4	9.4	8.0	-	11.5%	36%	76%
SCE	7/26/05	8 hours	3-Day	36	36	8.0	38.8	**4.6**	5.5	5.5	5.3	5.3	4.5	6.55	11.9%	43%	58%
SCE	7/26/05	8 hours	3-Day Coin	36	36	8.0	35.5	**1.8**	3.8	3.8	3.5	3.7	1.7	-	5.2%	43%	23%
SCE	7/26/05	8 hours	10-Day	36	36	8.0	34.7	**0.5**	3.4	3.4	3.3	3.3	0.6	-	1.3%	43%	6%
SCE	7/26/05	8 hours	10-Day Adj	36	36	8.0	37.2	**3.0**	5.2	5.2	5.2	5.0	3.0	-	8.0%	43%	37%
SCE	7/26/05	8 hours	8-Day	36	36	8.0	35.7	**1.5**	3.1	3.1	2.9	2.7	1.3	-	4.1%	43%	18%
SCE	7/27/05	8 hours	3-Day	38	38	20.9	126.0	**12.5**	14.4	14.3	13.7	14.2	12.9	10.90	9.9%	53%	60%
SCE	7/27/05	8 hours	3-Day Coin	38	38	20.9	97.2	**6.9**	10.1	10.1	9.9	10.0	7.1	-	7.1%	53%	33%
SCE	7/27/05	8 hours	10-Day	38	38	20.9	113.0	**-0.5**	8.4	8.3	8.3	8.3	0.1	-	-0.4%	53%	-2%
SCE	7/27/05	8 hours	10-Day Adj	38	38	20.9	115.4	**1.9**	10.6	10.6	10.5	10.4	2.9	-	1.6%	53%	9%
SCE	7/27/05	8 hours	8-Day	38	38	20.9	114.3	**0.8**	7.5	7.5	7.4	7.4	1.2	-	0.7%	53%	4%
SCE	7/29/05	8 hours	3-Day	44	45	14.6	99.1	**13.6**	14.5	14.5	14.0	14.2	13.2	22.27	13.7%	63%	93%
SCE	7/29/05	8 hours	3-Day Coin	44	45	14.6	71.9	**8.2**	10.1	10.1	9.9	9.8	8.2	-	11.5%	63%	56%
SCE	7/29/05	8 hours	10-Day	44	45	14.6	87.2	**1.6**	6.7	6.7	6.7	6.5	2.5	-	1.9%	63%	11%
SCE	7/29/05	8 hours	10-Day Adj	44	45	14.6	95.5	**10.0**	12.2	12.2	11.4	11.9	9.1	-	10.4%	63%	68%
SCE	7/29/05	8 hours	8-Day	44	45	14.6	91.3	**5.7**	9.0	9.0	8.1	8.7	4.9	-	6.3%	63%	39%
SCE	8/4/05	8 hours	3-Day	39	39	21.7	118.3	**20.5**	20.8	20.8	20.3	20.5	20.1	14.51	17.3%	60%	94%
SCE	8/4/05	8 hours	3-Day Coin	39	39	21.7	93.2	**14.5**	16.5	16.5	16.3	16.4	14.6	-	15.6%	60%	67%
SCE	8/4/05	8 hours	10-Day	39	39	21.7	106.6	**8.8**	11.1	11.1	10.8	11.0	9.2	-	8.3%	60%	41%
SCE	8/4/05	8 hours	10-Day Adj	39	39	21.7	96.6	**-1.3**	5.7	5.7	5.1	5.5	-1.7	-	-1.3%	60%	-6%
SCE	8/4/05	8 hours	8-Day	39	39	21.7	108.8	**11.0**	12.3	12.3	11.5	12.1	10.3	-	10.1%	60%	51%
SCE	8/5/05	8 hours	3-Day	40	40	20.7	113.0	**22.6**	22.8	22.8	22.5	22.6	22.4	15.64	20.0%	65%	109%
SCE	8/5/05	8 hours	3-Day Coin	40	40	20.7	85.5	**16.8**	17.5	17.5	17.5	17.4	16.9	-	19.7%	65%	81%
SCE	8/5/05	8 hours	10-Day	40	40	20.7	101.4	**11.0**	12.7	12.7	12.3	12.5	11.5	-	10.8%	65%	53%
SCE	8/5/05	8 hours	10-Day Adj	40	40	20.7	94.0	**3.6**	10.9	10.8	10.5	10.6	3.4	-	3.8%	65%	17%
SCE	8/5/05	8 hours	8-Day	40	40	20.7	102.3	**12.0**	12.9	12.8	12.3	12.6	11.7	-	11.7%	65%	58%

Exhibit D2-5 (con't)
Average Hourly Impact Estimates for SCE DBP Participants – Summer 2005 Events
Average over 12 Events

SCE DBP Events Summary - Average across Events

Program	Event Length	Baseline	N	n	Avg Hourly Bid (MW)	Estimated Load (MW)	Average Hourly Impacts (in MW)						Utility Reported	% Reduction	% Hourly Bids Paid	Bid RR%
							All	Positive	> 10kW	>5% Load	> 50kW	+/- 5% Load				
DBP	8 hours	3-Day	420	420	14.6	89.1	**11.3**	12.9	12.9	12.6	12.8	11.6	13.4	12.7%	42%	77%
DBP	8 hours	3-Day Coin	420	420	14.6	67.1	**7.3**	9.5	9.5	9.4	9.4	7.5	-	10.8%	42%	50%
DBP	8 hours	10-Day	420	420	14.6	79.9	**2.1**	6.8	6.8	6.7	6.7	2.5	-	2.6%	42%	14%
DBP	8 hours	10-Day Adj	420	420	14.6	80.4	**2.6**	7.2	7.2	6.9	7.0	2.8	-	3.2%	42%	18%
DBP	8 hours	8-Day	420	420	14.6	81.5	**3.7**	7.0	7.0	6.7	6.9	3.9	-	4.6%	42%	26%

Exhibit D2-6
Average Hourly Impact Estimates for SDG&E DBP Participants – Summer 2005 Events
12 Events

Utility	Event	Event Length	Baseline	N	n	Avg Hourly Bid (MW)	Estimated Load (MW)	Average Hourly Impacts (in MW)						Utility Reported	% Reduction	% Hourly Bids Paid	Bid RR%
								All	Positive	>10kW	>5% Load	>50kW	+/- 5% Load				
SDG&E	7/12/05	4 hours	3-Day	12	12	3.6	4.2	**0.4**	0.4	0.4	0.3	0.2	0.3	0.4	8.6%	31%	10%
SDG&E	7/12/05	4 hours	3-Day Coin	12	12	3.6	3.7	**-0.1**	0.3	0.2	0.2	0.1	-0.1	-	-2.0%	31%	-2%
SDG&E	7/12/05	4 hours	10-Day	12	12	3.6	3.8	**0.0**	0.2	0.2	0.2	0.1	0.0	-	0.2%	31%	0%
SDG&E	7/12/05	4 hours	10-Day Adj	12	12	3.6	3.9	**0.1**	0.2	0.2	0.2	0.1	0.1	-	3.2%	31%	3%
SDG&E	7/12/05	4 hours	8-Day	12	12	3.6	3.8	**0.0**	0.2	0.2	0.2	0.1	0.0	-	0.3%	31%	0%
SDG&E	7/13/05	4 hours	3-Day	13	13	5.0	6.8	**1.3**	1.4	1.4	1.4	1.3	1.3	1.3	19.6%	29%	27%
SDG&E	7/13/05	4 hours	3-Day Coin	13	13	5.0	6.7	**1.2**	1.3	1.3	1.3	1.2	1.2	-	17.9%	29%	24%
SDG&E	7/13/05	4 hours	10-Day	13	13	5.0	6.4	**0.9**	1.1	1.0	1.0	0.9	0.9	-	14.6%	29%	19%
SDG&E	7/13/05	4 hours	10-Day Adj	13	13	5.0	6.7	**1.2**	1.3	1.3	1.3	1.2	1.2	-	18.0%	29%	24%
SDG&E	7/13/05	4 hours	8-Day	13	13	5.0	6.4	**0.9**	1.0	1.0	1.0	0.9	0.9	-	14.5%	29%	19%
SDG&E	7/14/05	4 hours	3-Day	11	11	2.4	5.5	**0.7**	0.8	0.7	0.7	0.7	0.7	0.7	12.8%	25%	29%
SDG&E	7/14/05	4 hours	3-Day Coin	11	11	2.4	5.4	**0.6**	0.7	0.7	0.7	0.7	0.5	-	10.4%	25%	23%
SDG&E	7/14/05	4 hours	10-Day	11	11	2.4	5.2	**0.3**	0.5	0.4	0.4	0.4	0.3	-	6.7%	25%	14%
SDG&E	7/14/05	4 hours	10-Day Adj	11	11	2.4	5.4	**0.6**	0.7	0.7	0.7	0.6	0.5	-	10.5%	25%	23%
SDG&E	7/14/05	4 hours	8-Day	11	11	2.4	5.1	**0.3**	0.4	0.4	0.4	0.3	0.2	-	5.8%	25%	12%
SDG&E	7/15/05	3 hours	3-Day	11	11	2.1	5.2	**0.8**	0.9	0.9	0.9	0.9	0.8	0.8	16.1%	48%	40%
SDG&E	7/15/05	3 hours	3-Day Coin	11	11	2.1	5.0	**0.6**	0.9	0.8	0.8	0.8	0.6	-	13.0%	48%	31%
SDG&E	7/15/05	3 hours	10-Day	11	11	2.1	4.8	**0.4**	0.6	0.6	0.6	0.5	0.5	-	9.3%	48%	22%
SDG&E	7/15/05	3 hours	10-Day Adj	11	11	2.1	5.0	**0.7**	0.8	0.8	0.8	0.8	0.7	-	13.4%	48%	32%
SDG&E	7/15/05	3 hours	8-Day	11	11	2.1	4.7	**0.4**	0.6	0.5	0.5	0.4	0.4	-	8.1%	48%	18%
SDG&E	7/19/05	5 hours	3-Day	8	8	3.9	2.9	**0.6**	0.8	0.7	0.7	0.7	0.6	0.6	20.7%	30%	15%
SDG&E	7/19/05	5 hours	3-Day Coin	8	8	3.9	2.7	**0.5**	0.7	0.6	0.7	0.6	0.5	-	16.7%	30%	12%
SDG&E	7/19/05	5 hours	10-Day	8	8	3.9	2.5	**0.3**	0.5	0.5	0.5	0.4	0.3	-	10.7%	30%	7%
SDG&E	7/19/05	5 hours	10-Day Adj	8	8	3.9	3.0	**0.7**	0.8	0.7	0.7	0.7	0.7	-	23.3%	30%	18%
SDG&E	7/19/05	5 hours	8-Day	8	8	3.9	2.6	**0.3**	0.5	0.5	0.5	0.4	0.3	-	11.3%	30%	7%
SDG&E	7/20/05	3 hours	3-Day	8	8	2.8	4.0	**0.2**	0.2	0.2	0.2	0.1	0.1	0.2	4.2%	38%	6%
SDG&E	7/20/05	3 hours	3-Day Coin	8	8	2.8	3.9	**0.0**	0.2	0.2	0.1	0.1	0.0	-	1.0%	38%	1%
SDG&E	7/20/05	3 hours	10-Day	8	8	2.8	3.9	**0.0**	0.1	0.1	0.1	0.1	0.0	-	1.0%	38%	1%
SDG&E	7/20/05	3 hours	10-Day Adj	8	8	2.8	4.0	**0.2**	0.2	0.2	0.2	0.1	0.2	-	4.5%	38%	7%
SDG&E	7/20/05	3 hours	8-Day	8	8	2.8	3.9	**0.1**	0.1	0.1	0.1	0.0	0.0	-	1.4%	38%	2%
SDG&E	7/21/05	3 hours	3-Day	6	6	0.4	1.3	**-0.1**	0.1	0.1	0.1	0.0	-0.1	0.0	-5.7%	11%	-21%
SDG&E	7/21/05	3 hours	3-Day Coin	6	6	0.4	1.3	**-0.1**	0.0	0.0	0.0	0.0	-0.1	-	-9.4%	11%	-33%
SDG&E	7/21/05	3 hours	10-Day	6	6	0.4	1.3	**-0.2**	0.0	0.0	0.0	0.0	-0.2	-	-11.9%	11%	-41%
SDG&E	7/21/05	3 hours	10-Day Adj	6	6	0.4	1.3	**-0.1**	0.0	0.0	0.0	0.0	-0.1	-	-8.7%	11%	-31%
SDG&E	7/21/05	3 hours	8-Day	6	6	0.4	1.3	**-0.1**	0.0	0.0	0.0	0.0	-0.1	-	-9.0%	11%	-32%
SDG&E	7/22/05	5 hours	3-Day	8	8	1.8	2.3	**0.5**	0.6	0.6	0.6	0.5	0.5	0.5	19.9%	35%	26%
SDG&E	7/22/05	5 hours	3-Day Coin	8	8	1.8	2.2	**0.3**	0.5	0.5	0.5	0.4	0.3	-	15.4%	35%	19%
SDG&E	7/22/05	5 hours	10-Day	8	8	1.8	2.0	**0.2**	0.3	0.3	0.3	0.3	0.2	-	8.0%	35%	9%
SDG&E	7/22/05	5 hours	10-Day Adj	8	8	1.8	2.3	**0.4**	0.5	0.5	0.5	0.5	0.4	-	18.5%	35%	23%
SDG&E	7/22/05	5 hours	8-Day	8	8	1.8	1.9	**0.0**	0.2	0.2	0.2	0.1	0.0	-	1.7%	35%	2%
SDG&E	7/26/05	3 hours	3-Day	7	7	2.7	3.5	**-0.2**	0.1	0.1	0.1	0.1	-0.2	0.0	-6.0%	10%	-8%
SDG&E	7/26/05	3 hours	3-Day Coin	7	7	2.7	3.4	**-0.3**	0.1	0.1	0.1	0.1	-0.3	-	-8.8%	10%	-11%
SDG&E	7/26/05	3 hours	10-Day	7	7	2.7	3.4	**-0.3**	0.1	0.1	0.1	0.0	-0.3	-	-9.3%	10%	-12%
SDG&E	7/26/05	3 hours	10-Day Adj	7	7	2.7	3.6	**-0.1**	0.1	0.1	0.1	0.1	-0.1	-	-3.3%	10%	-4%
SDG&E	7/26/05	3 hours	8-Day	7	7	2.7	3.5	**-0.3**	0.0	0.0	0.0	0.0	-0.2	-	-8.4%	10%	-11%
SDG&E	7/27/05	2 hours	3-Day	7	7	5.7	6.7	**1.7**	1.9	1.9	1.8	1.8	1.7	1.8	26.1%	43%	31%
SDG&E	7/27/05	2 hours	3-Day Coin	7	7	5.7	6.2	**1.2**	1.4	1.4	1.4	1.4	1.2	-	20.1%	43%	22%
SDG&E	7/27/05	2 hours	10-Day	7	7	5.7	6.1	**1.1**	1.4	1.4	1.3	1.4	1.0	-	18.2%	43%	20%
SDG&E	7/27/05	2 hours	10-Day Adj	7	7	5.7	6.2	**1.3**	1.4	1.4	1.3	1.4	1.2	-	20.6%	43%	23%
SDG&E	7/27/05	2 hours	8-Day	7	7	5.7	5.8	**0.9**	1.1	1.1	1.1	1.0	0.9	-	15.0%	43%	15%
SDG&E	8/4/05	2 hours	3-Day	8	8	4.2	7.0	**0.9**	0.9	0.9	0.9	0.8	0.9	0.8	12.3%	63%	21%
SDG&E	8/4/05	2 hours	3-Day Coin	8	8	4.2	6.4	**0.3**	0.3	0.3	0.2	0.2	0.2	-	5.1%	63%	8%
SDG&E	8/4/05	2 hours	10-Day	8	8	4.2	6.4	**0.3**	0.4	0.4	0.3	0.4	0.2	-	4.1%	63%	6%
SDG&E	8/4/05	2 hours	10-Day Adj	8	8	4.2	6.3	**0.2**	0.3	0.3	0.2	0.3	0.1	-	2.4%	63%	4%
SDG&E	8/4/05	2 hours	8-Day	8	8	4.2	6.5	**0.3**	0.4	0.4	0.3	0.3	0.3	-	5.3%	63%	8%
SDG&E	8/5/05	3 hours	3-Day	4	4	2.9	3.5	**0.5**	0.5	0.5	0.5	0.5	0.5	0.4	14.7%	33%	18%
SDG&E	8/5/05	3 hours	3-Day Coin	4	4	2.9	3.1	**0.2**	0.2	0.2	0.2	0.1	0.2	-	4.8%	33%	5%
SDG&E	8/5/05	3 hours	10-Day	4	4	2.9	3.2	**0.2**	0.2	0.2	0.2	0.2	0.2	-	5.8%	33%	6%
SDG&E	8/5/05	3 hours	10-Day Adj	4	4	2.9	3.1	**0.2**	0.2	0.2	0.2	0.1	0.2	-	5.0%	33%	5%
SDG&E	8/5/05	3 hours	8-Day	4	4	2.9	3.1	**0.1**	0.1	0.1	0.1	0.1	0.1	-	3.1%	33%	3%

Exhibit D2-6 (con't)
Average Hourly Impact Estimates for SDG&E DBP Participants – Summer 2005 Events
Average over 12 Events

SDG&E DBP Events Summary - Average across Events

Program	Event Length	Baseline	N	n	Avg Hourly Bid (MW)	Estimated Load (MW)	Average Hourly Impacts (in MW)						Utility Reported	% Reduction	% Hourly Bids Paid	Bid RR%
							All	Positive	>10kW	>5% Load	>50kW	+/- 5% Load				
DBP	3.4	3-Day	103	103	3.1	4.4	**0.6**	0.7	0.7	0.7	0.6	0.6	0.6	13.8%	33%	20%
DBP	3.4	3-Day Coin	103	103	3.1	4.2	**0.4**	0.5	0.5	0.5	0.5	0.4	-	8.9%	33%	12%
DBP	3.4	10-Day	103	103	3.1	4.1	**0.3**	0.5	0.4	0.4	0.4	0.3	-	6.7%	33%	9%
DBP	3.4	10-Day Adj	103	103	3.1	4.2	**0.4**	0.5	0.5	0.5	0.5	0.4	-	10.3%	33%	14%
DBP	3.4	8-Day	103	103	3.1	4.0	**0.2**	0.4	0.4	0.4	0.3	0.2	-	6.0%	33%	8%

D3. CPP and DBP Average Daily Load Shapes Across All Customers by Event

D3. CPP AND DBP AVERAGE DAILY LOAD SHAPES ACROSS ALL CUSTOMERS BY EVENT

The CPP and DBP Average Daily Load Shape Exhibits included in Appendix D3 present the average daily predicted load shape for each of the five baselines evaluated, as well as the average actual event day load shape for each of the 2005 CPP and DBP events. The DBP exhibits also provide the average hourly bid across all bidders for each event hour. For CPP the average predicted load shapes are based on all CPP participants for which interval data was available. The DBP average predicted load shapes include only those DBP participants who placed a bid for a particular event.

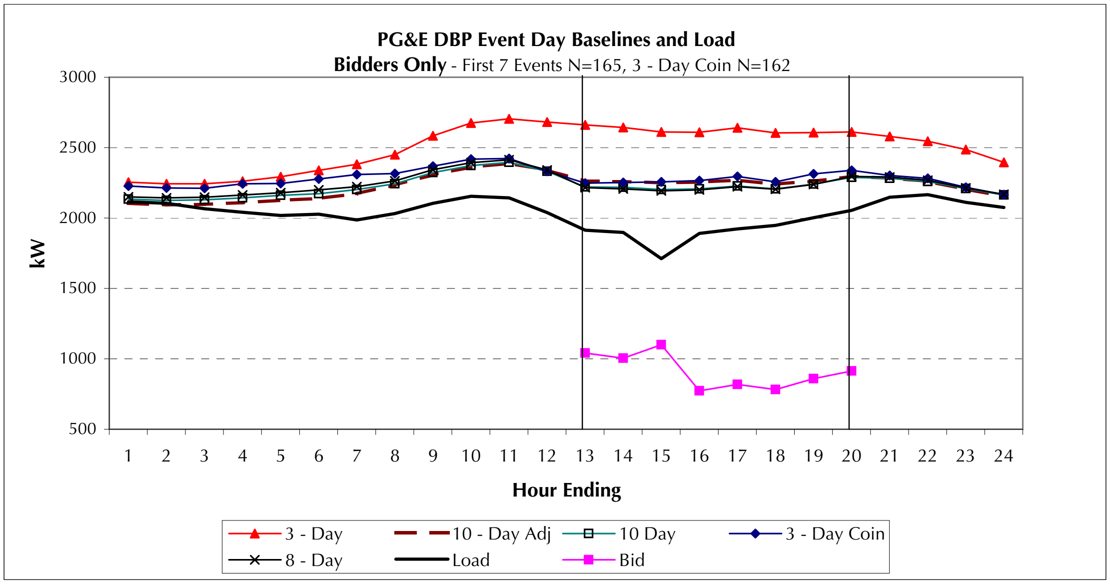
The vertical bars in these exhibits indicate the CPP and DBP event start and finish times. CPP events ran from 12PM – 6PM (12PM start = Hour Ending 13) within the PG&E and SCE service territories, and from 11AM – 6PM (11AM start = Hour Ending 12) within the SDG&E service territory. All DBP events for PG&E and SCE were called from 12PM – 8PM (12PM start = Hour Ending 13). For SDG&E DBP events were called for time periods between 12PM - 8PM.

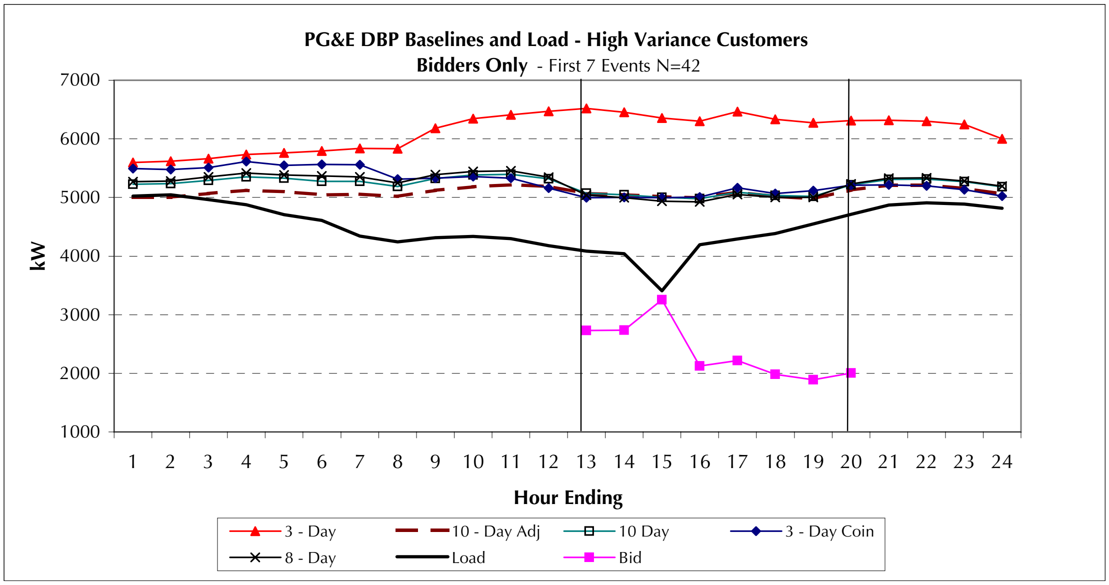
The load shape exhibits are broken into six sections – a CPP and DBP section for each of the three utilities. Each section contains a series of load shape graphs for each event day during the summer of 2005. These graphs include the estimated load shapes and baselines across all customers, across High Load-High Variance (HLHV) customers only, and across all customers not identified as HLHV. The exception to this is for SCE CPP and SDG&E DBP which only include the exhibits across all customers since no HLHV customers were identified as according to the identification algorithm.

Exhibit Sections Included:

- D3-1 PG&E DBP Average Event Day Baselines, Actual Load and Bids
- D3-2 SCE DBP Average Event Day Baselines, Actual Load and Bids
- D3-3 SDG&E DBP Average Event Day Baselines, Actual Load and Bids
- D3-4 PG&E CPP Average Event Day Baselines and Actual Load
- D3-5 SCE CPP Average Event Day Baselines and Actual Load
- D3-6 SDG&E CPP Average Event Day Baselines and Actual Load

Exhibit D3-1
PG&E DBP Event Day Baselines and Load





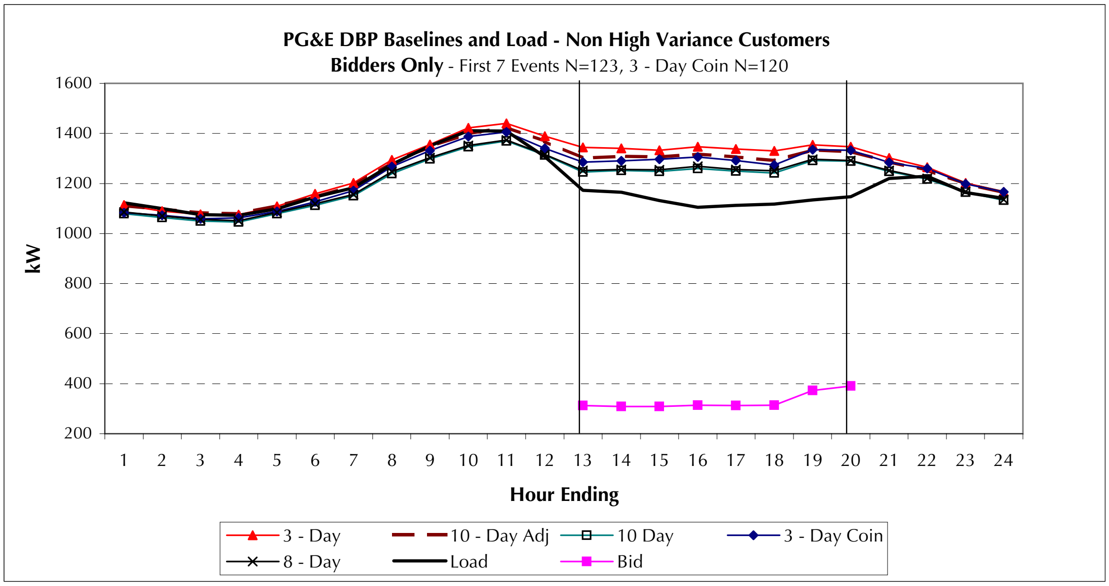
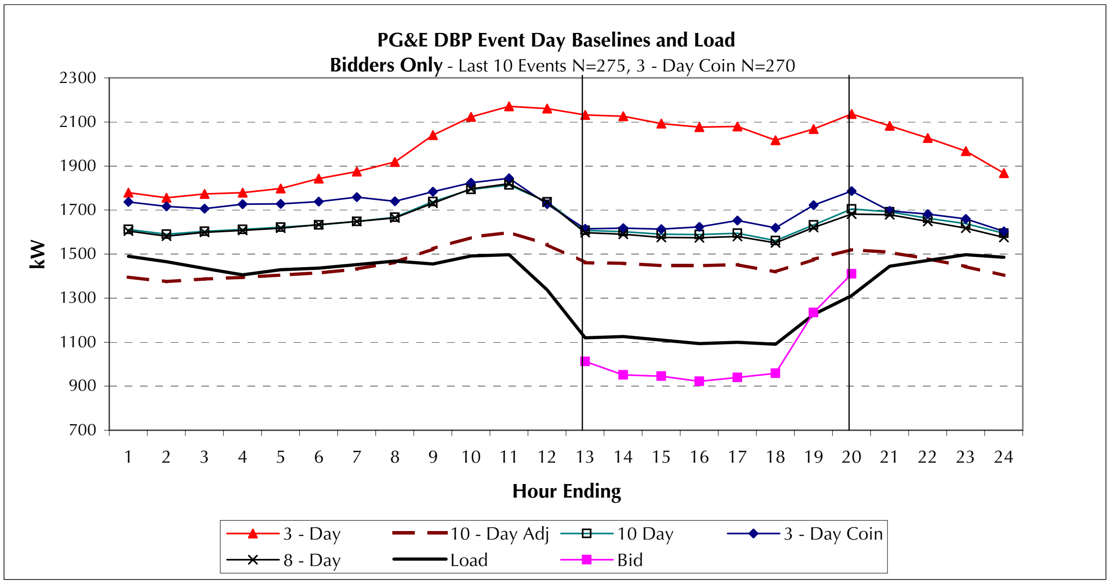
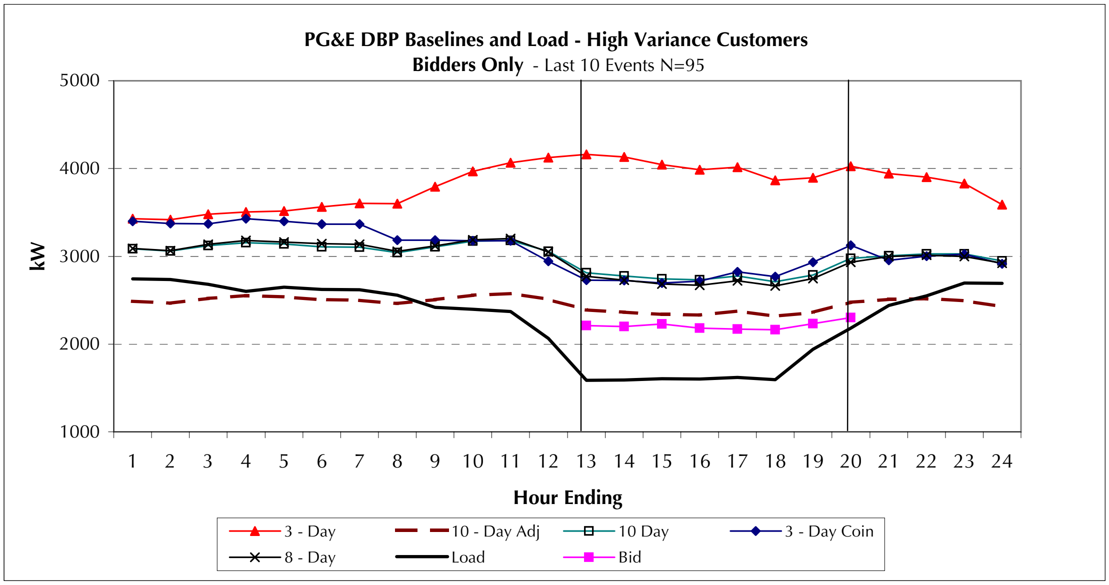


Exhibit D3-1 (Cont.)
PG&E DBP Event Day Baselines and Load





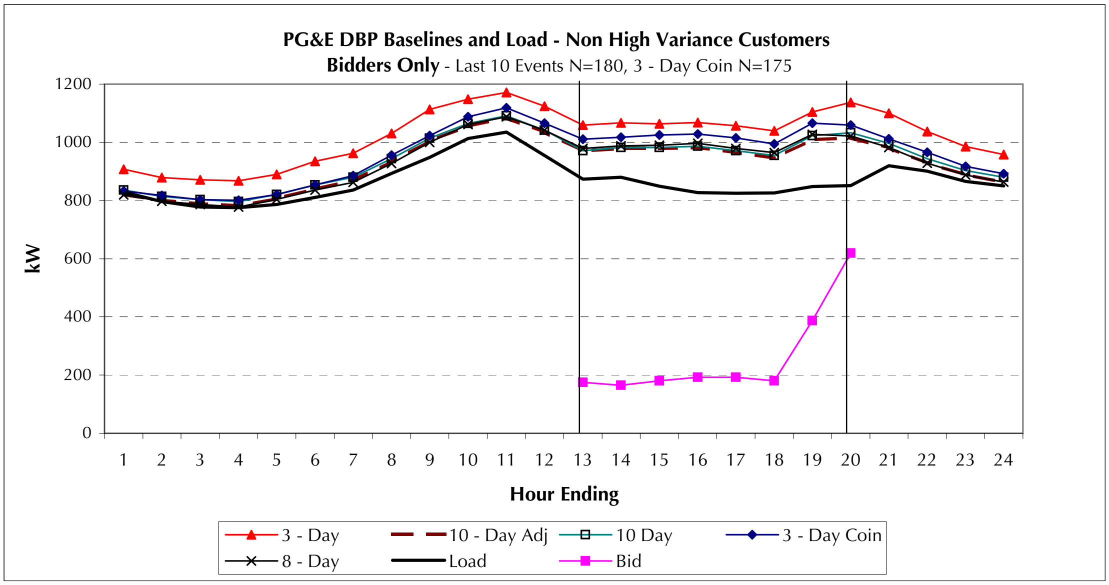
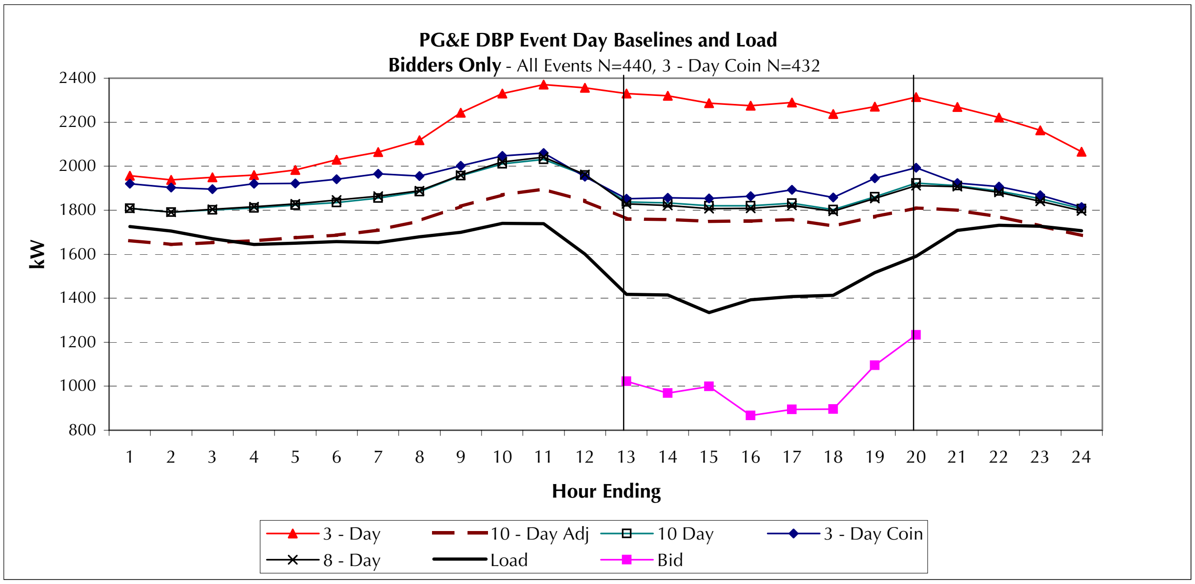
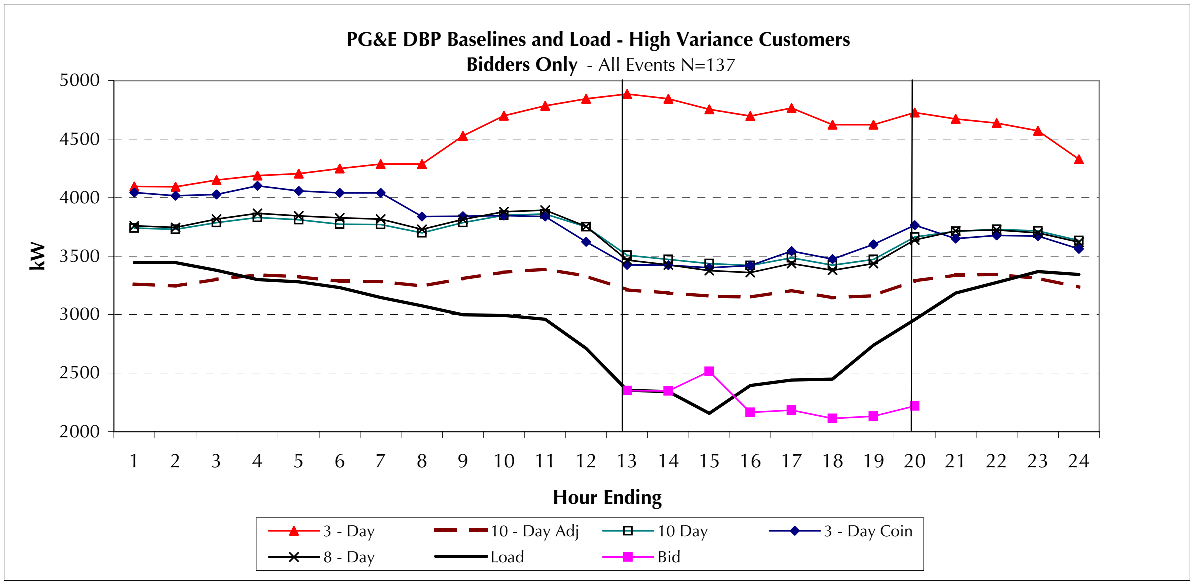


Exhibit D3-1 (Cont.)
PG&E DBP Event Day Baselines and Load





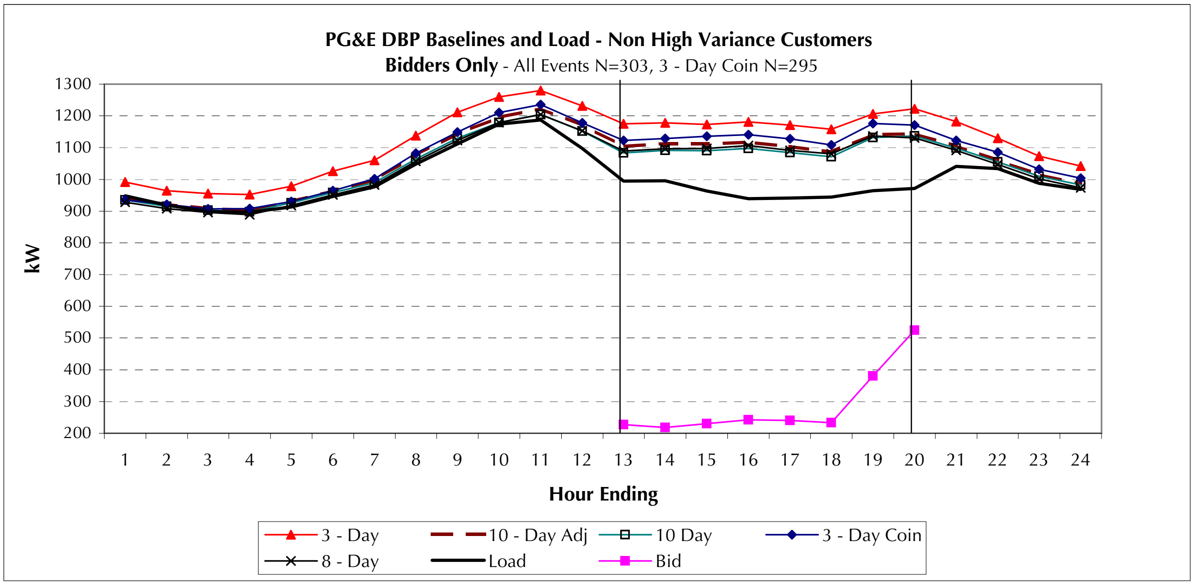
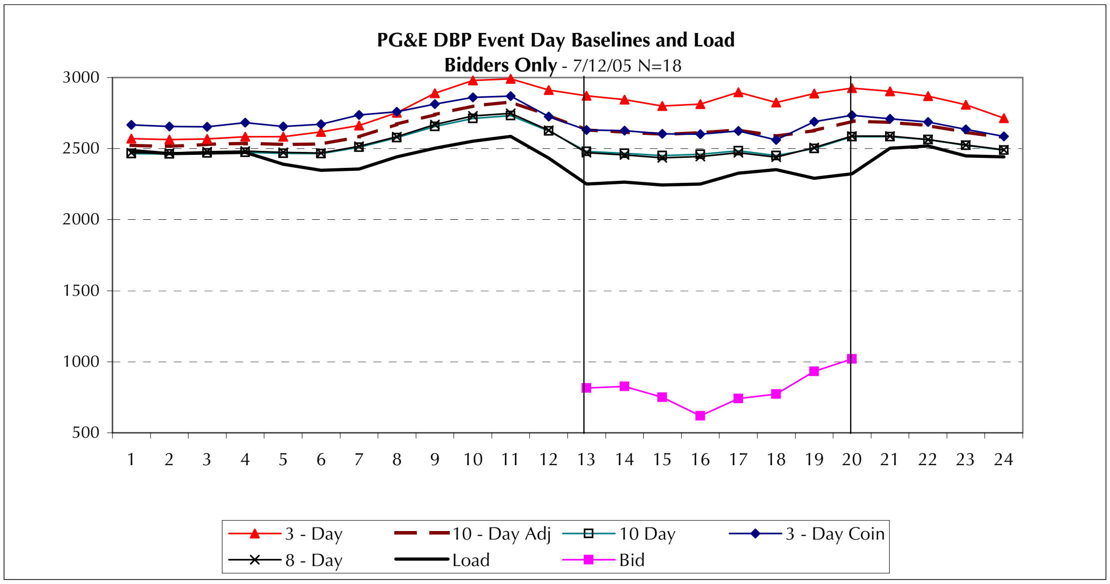
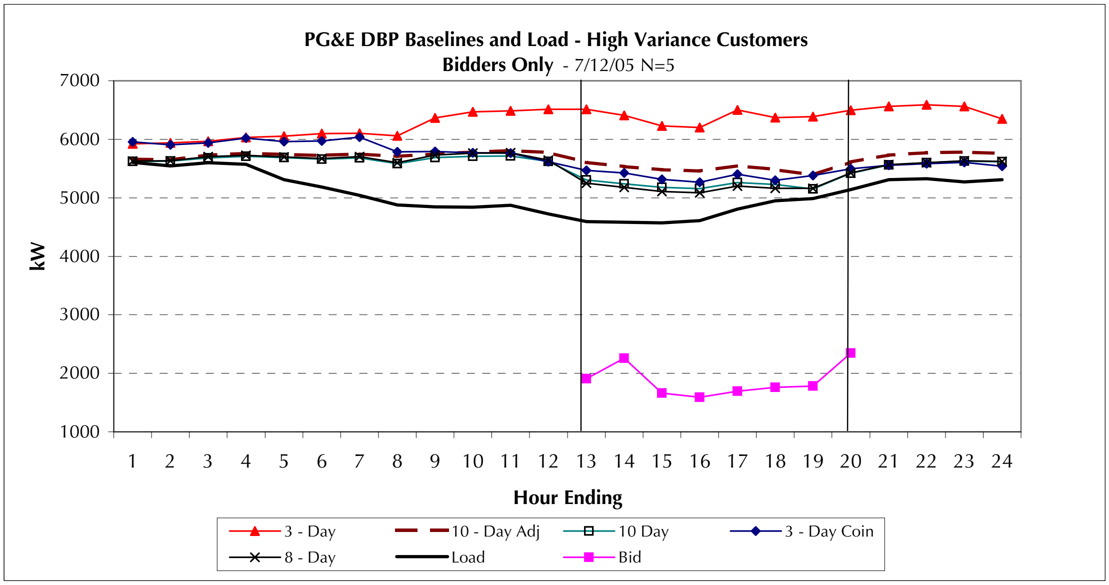


Exhibit D3-1 (Cont.)
PG&E DBP Event Day Baselines and Load





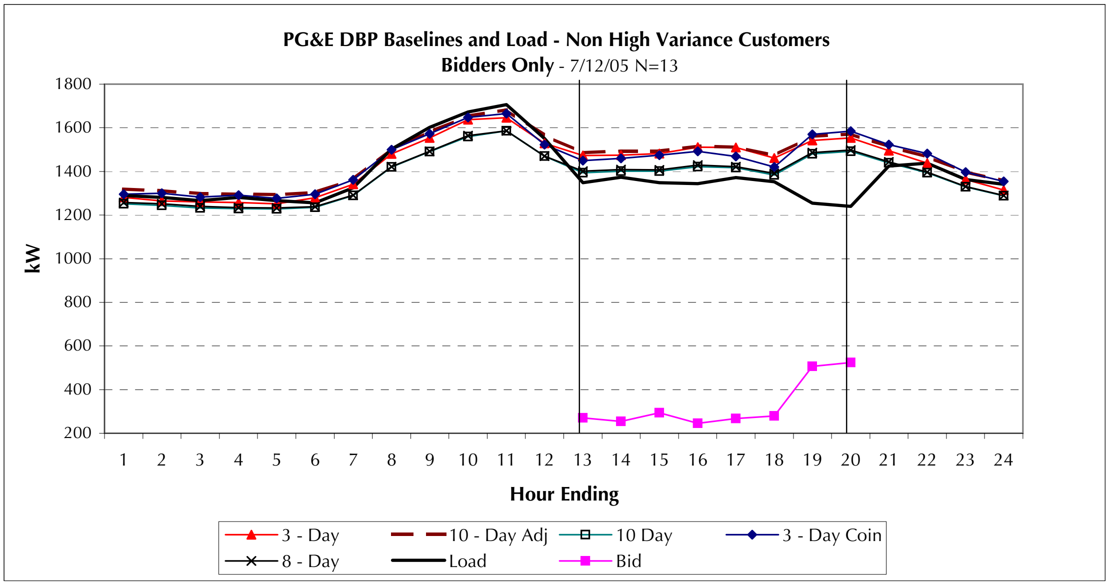
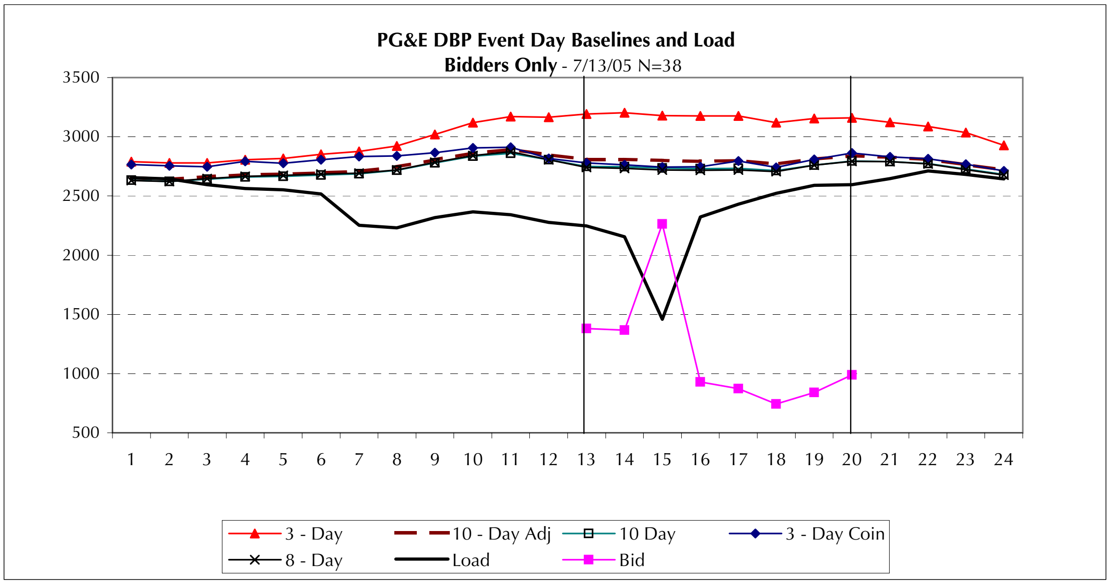
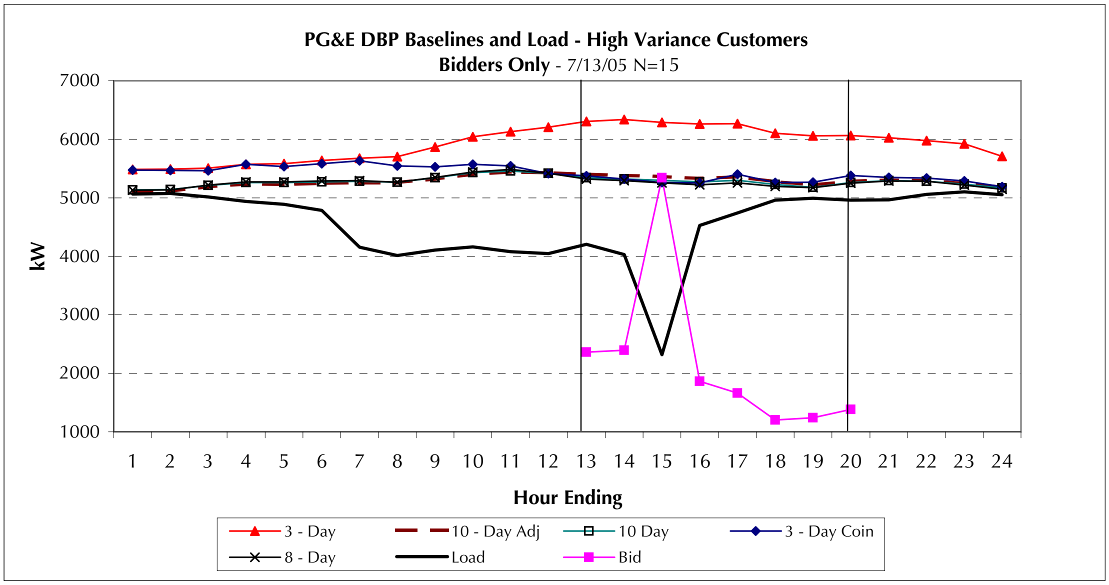


Exhibit D3-1 (Cont.)
PG&E DBP Event Day Baselines and Load





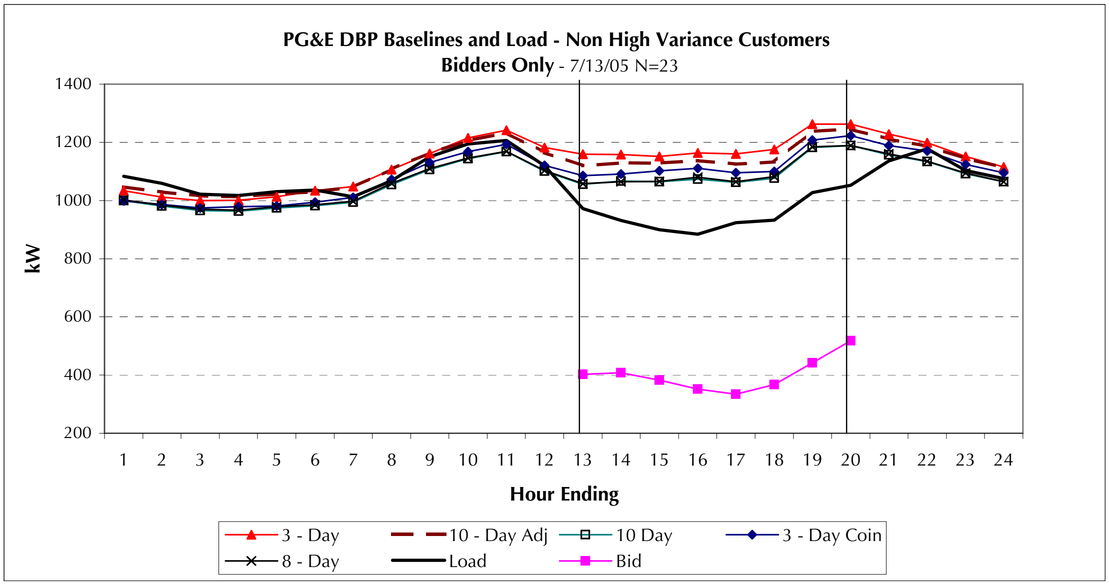
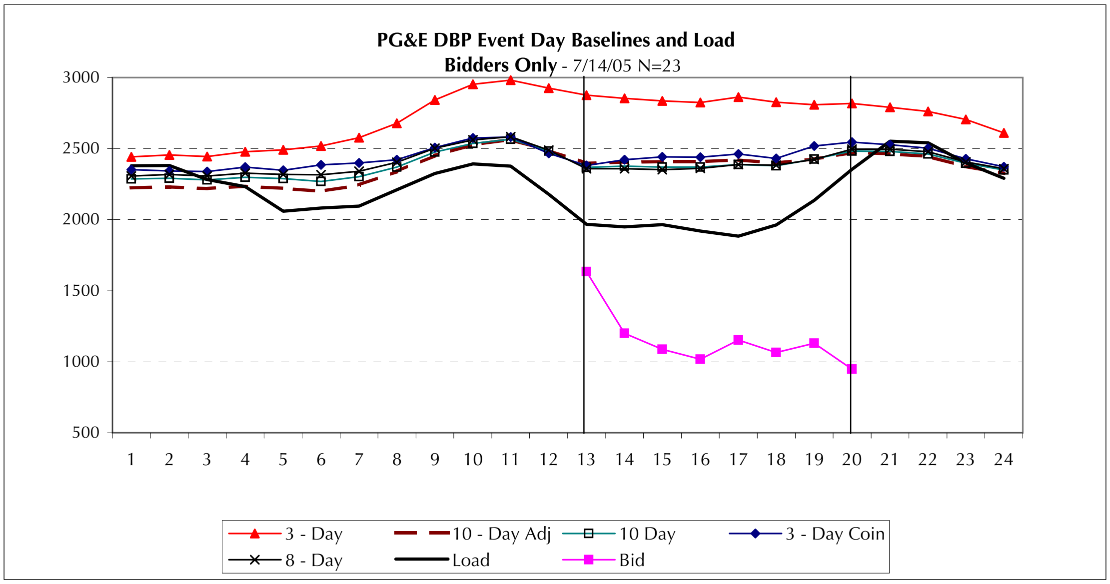
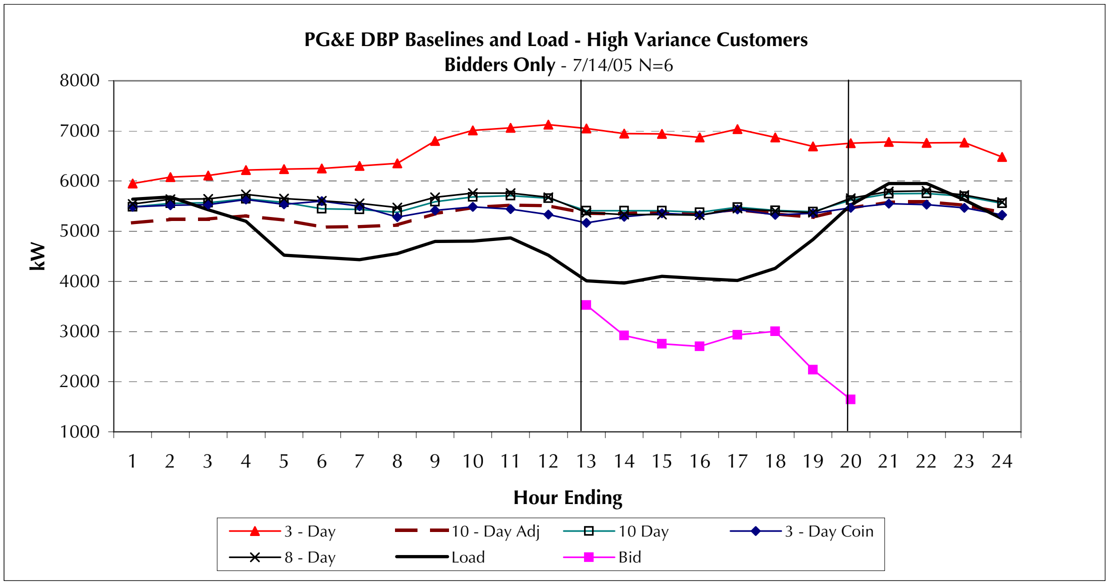


Exhibit D3-1 (Cont.)
PG&E DBP Event Day Baselines and Load





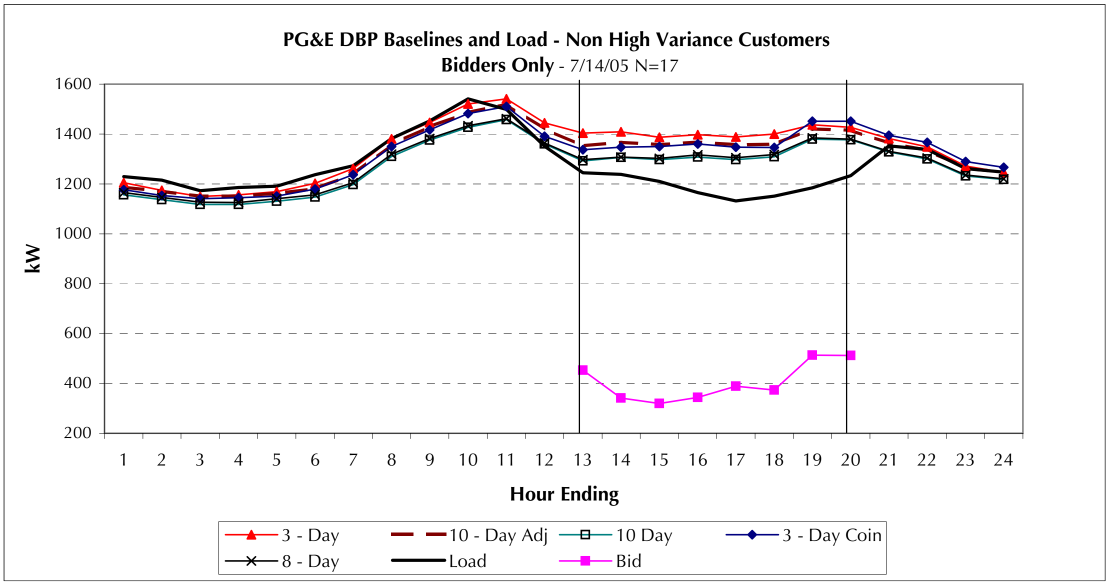
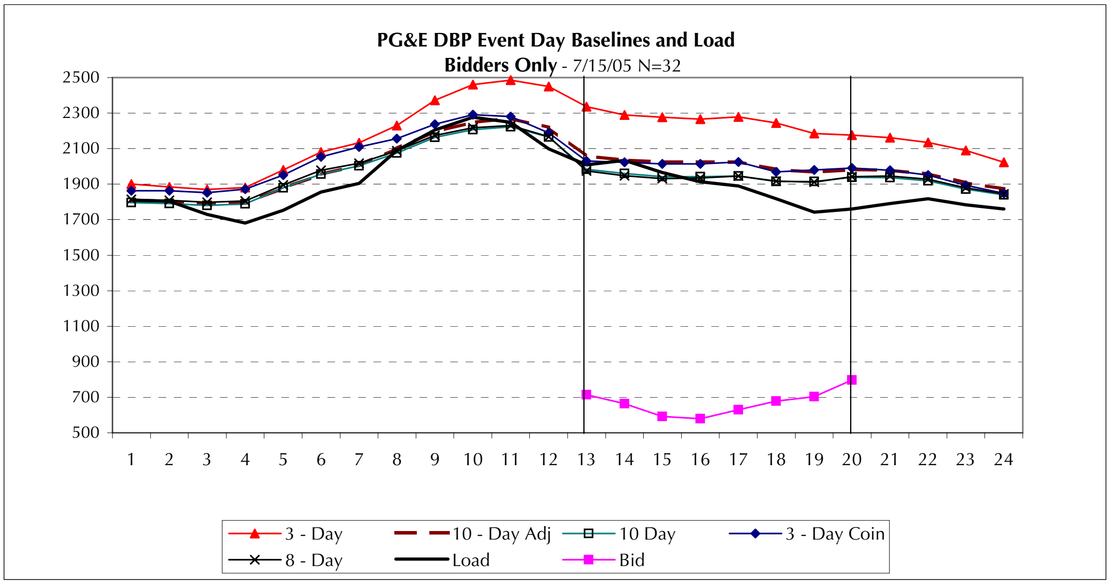
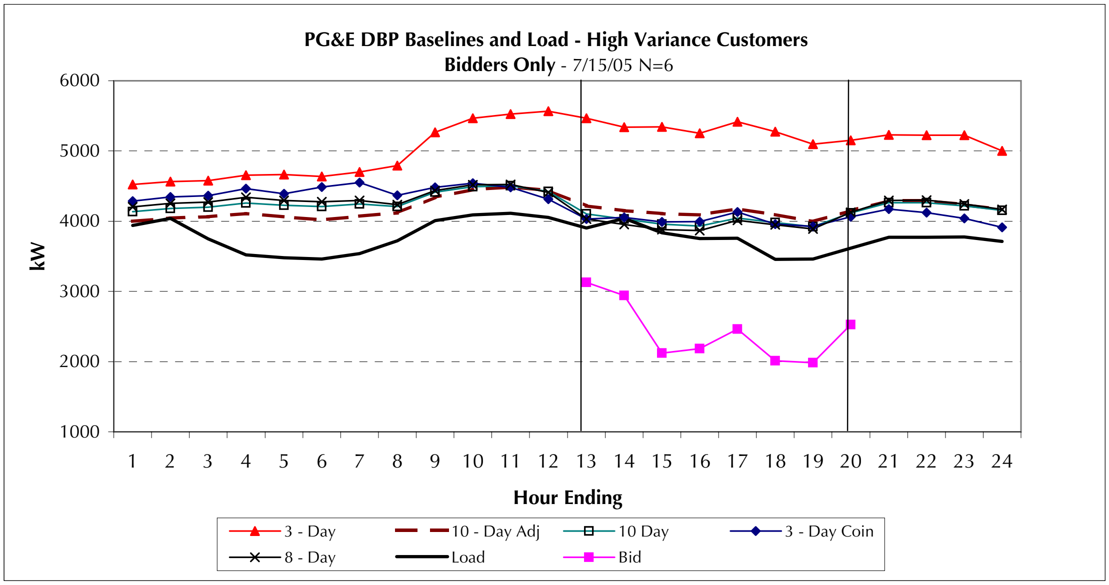


Exhibit D3-1 (Cont.)
PG&E DBP Event Day Baselines and Load





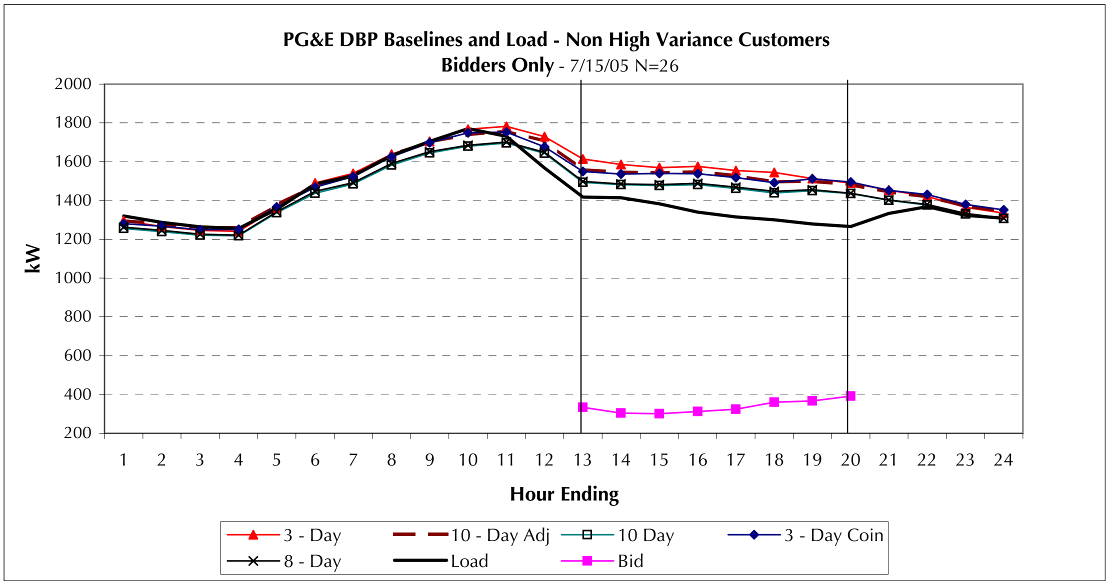
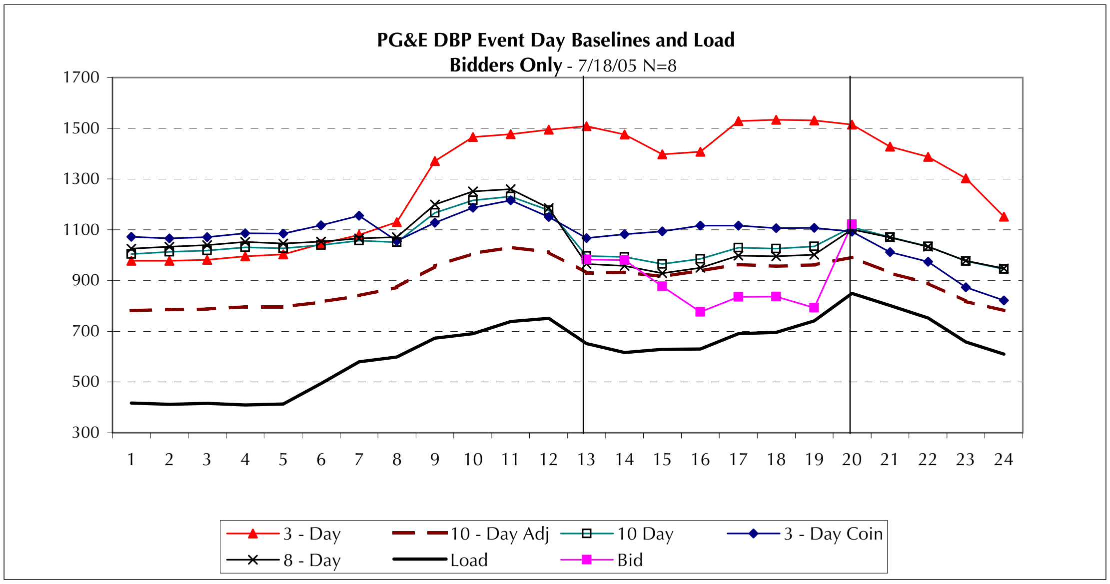
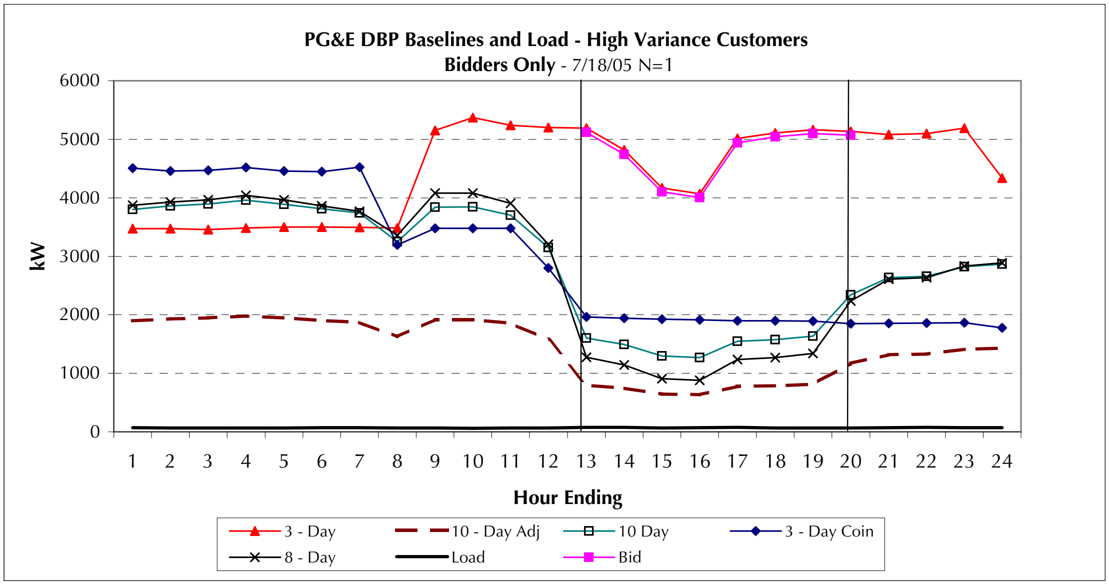


Exhibit D3-1 (Cont.)
PG&E DBP Event Day Baselines and Load





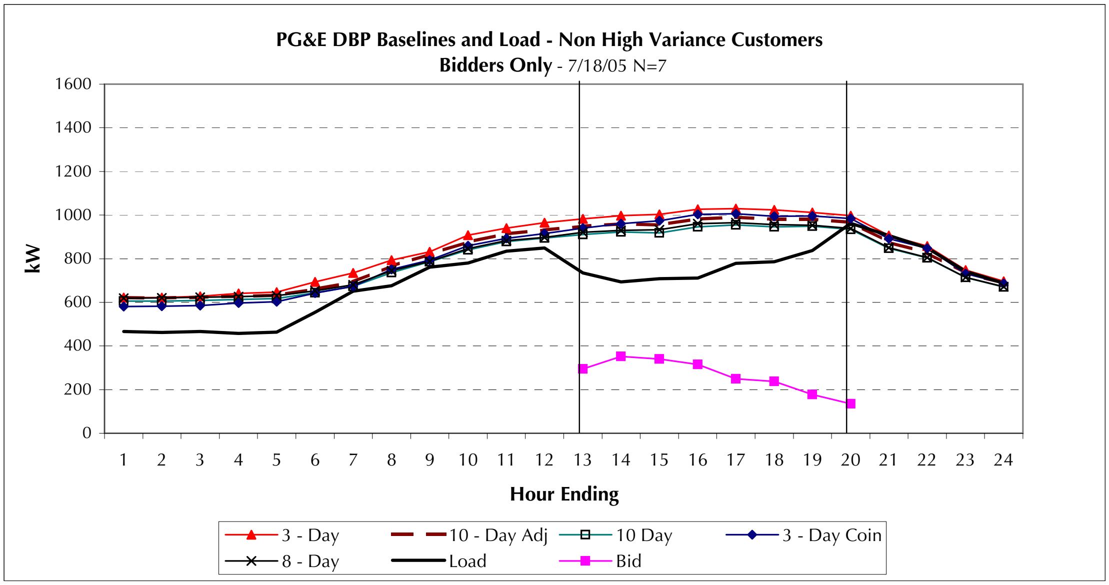
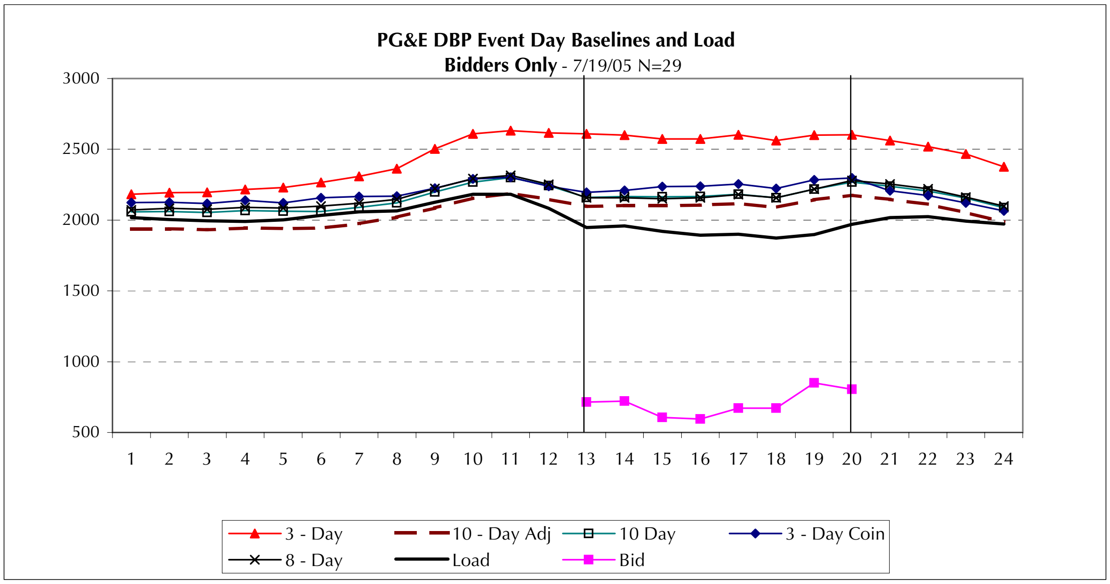
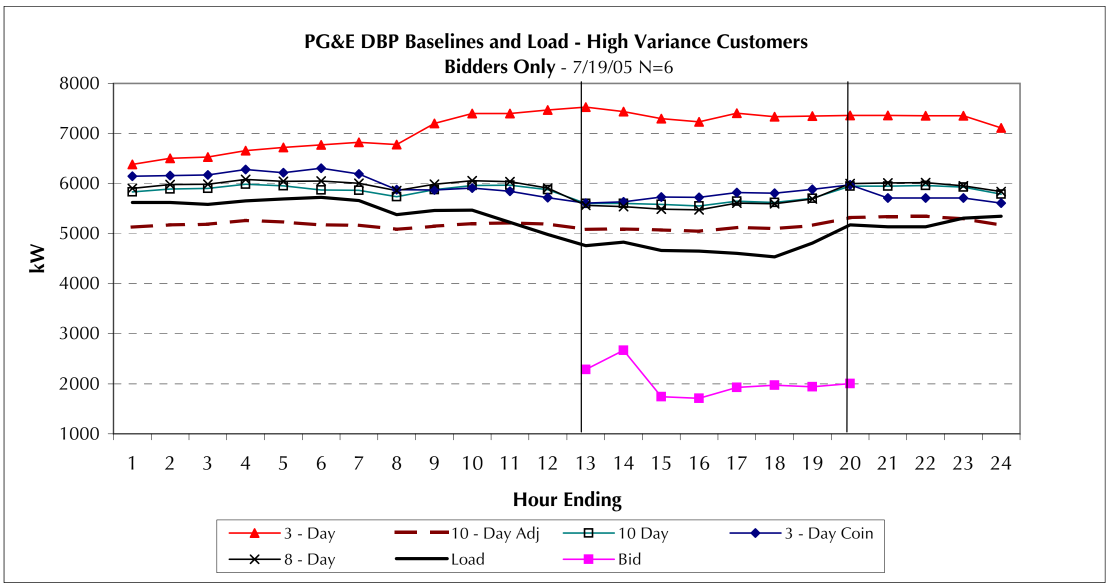


Exhibit D3-1 (Cont.)
PG&E DBP Event Day Baselines and Load





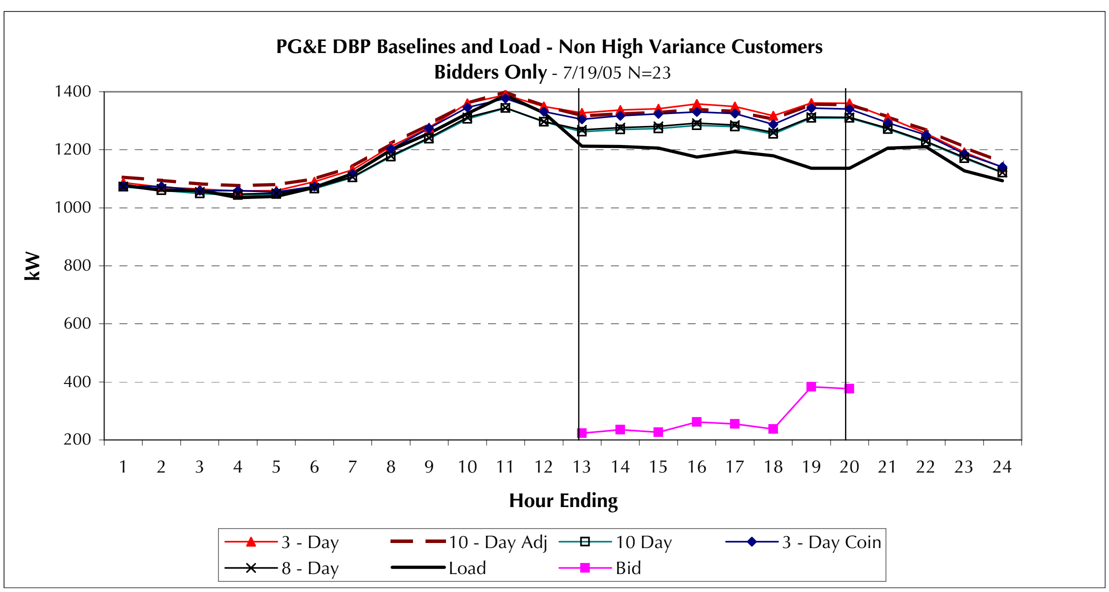
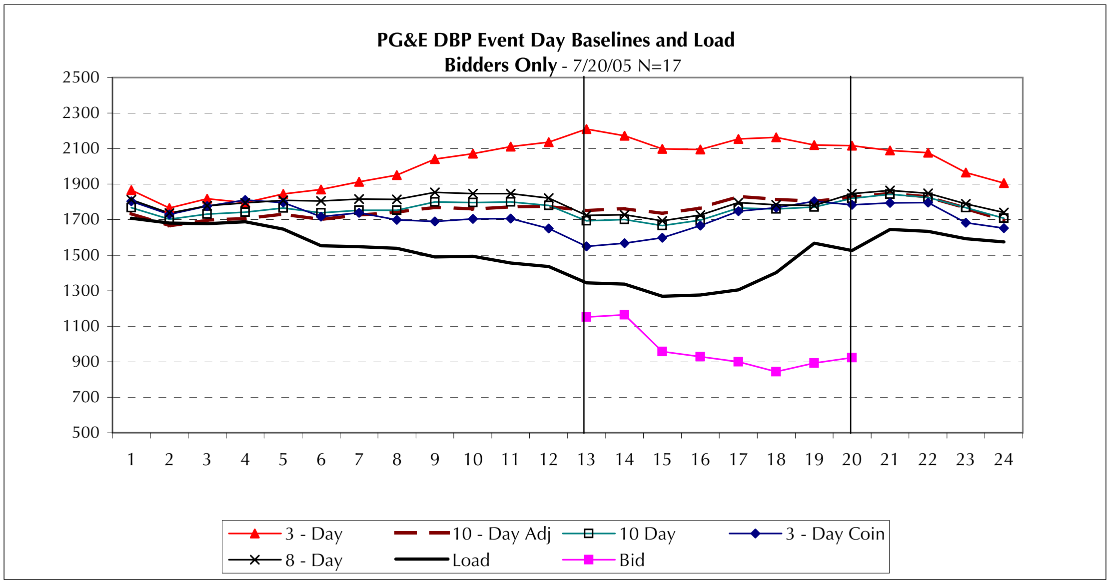
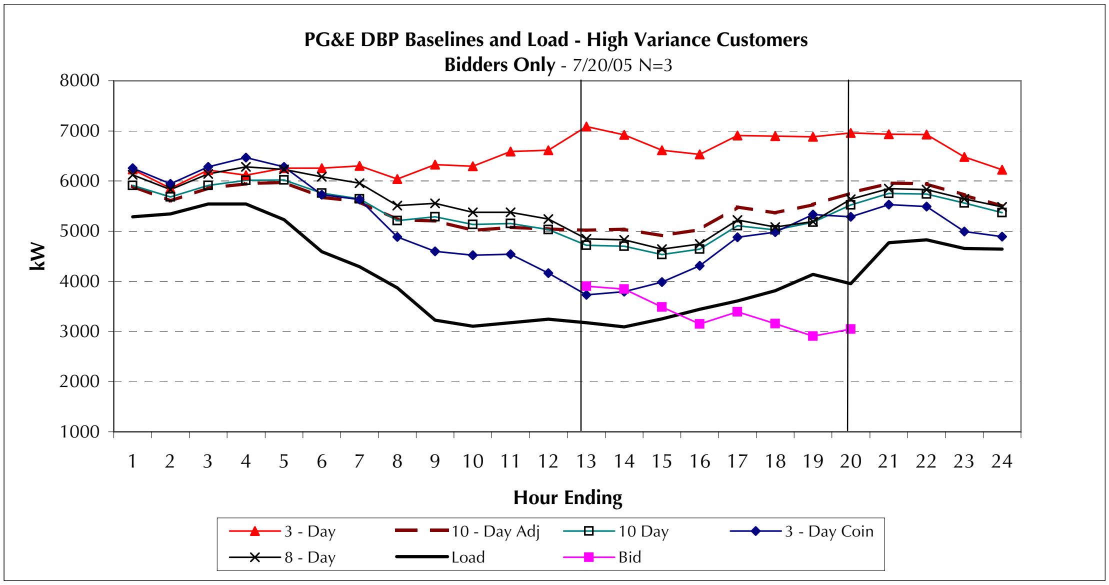


Exhibit D3-1 (Cont.)
PG&E DBP Event Day Baselines and Load





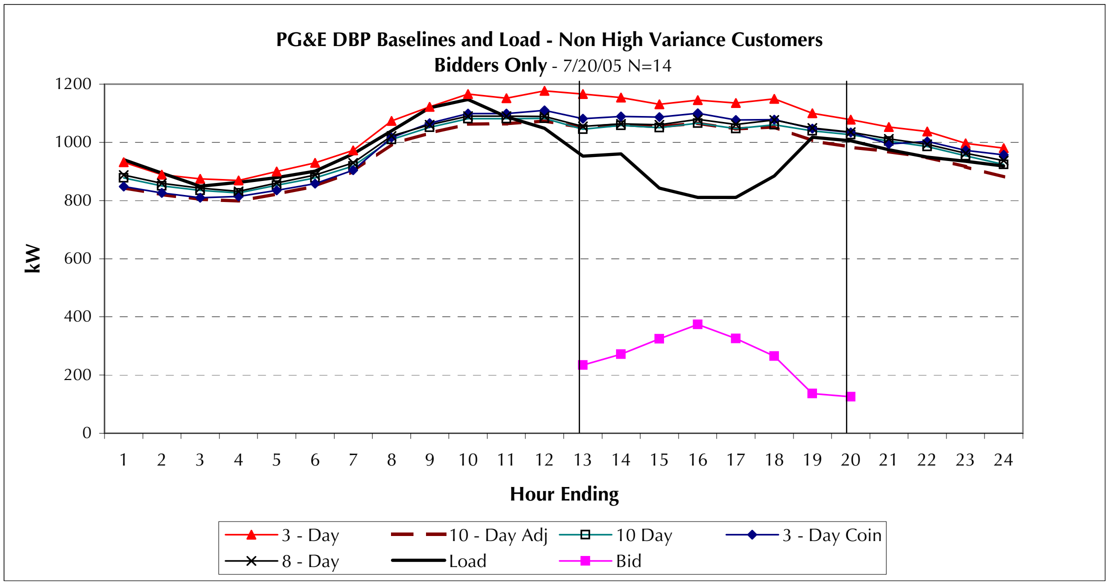
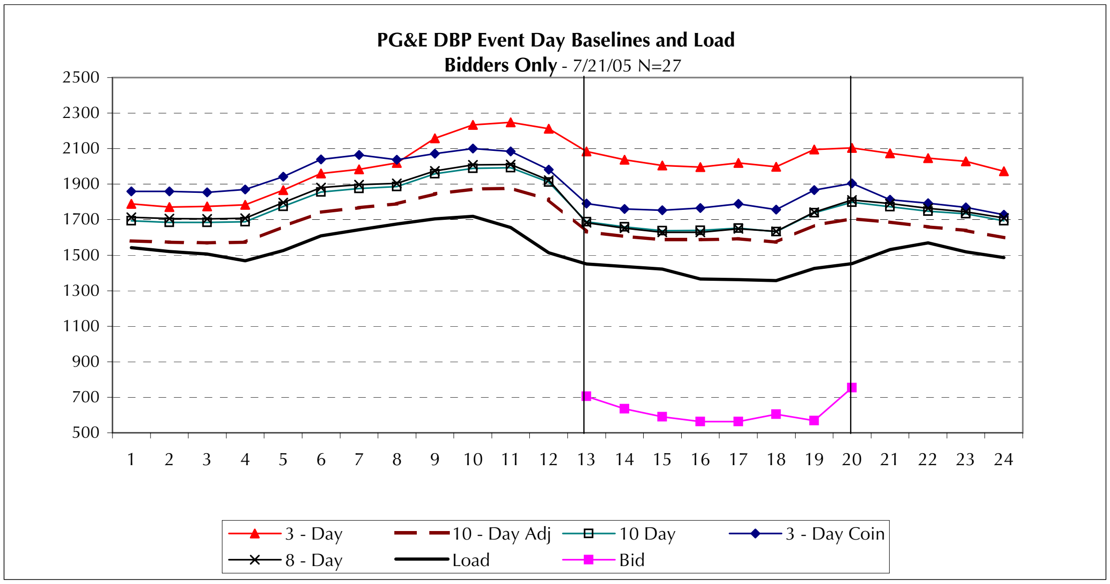
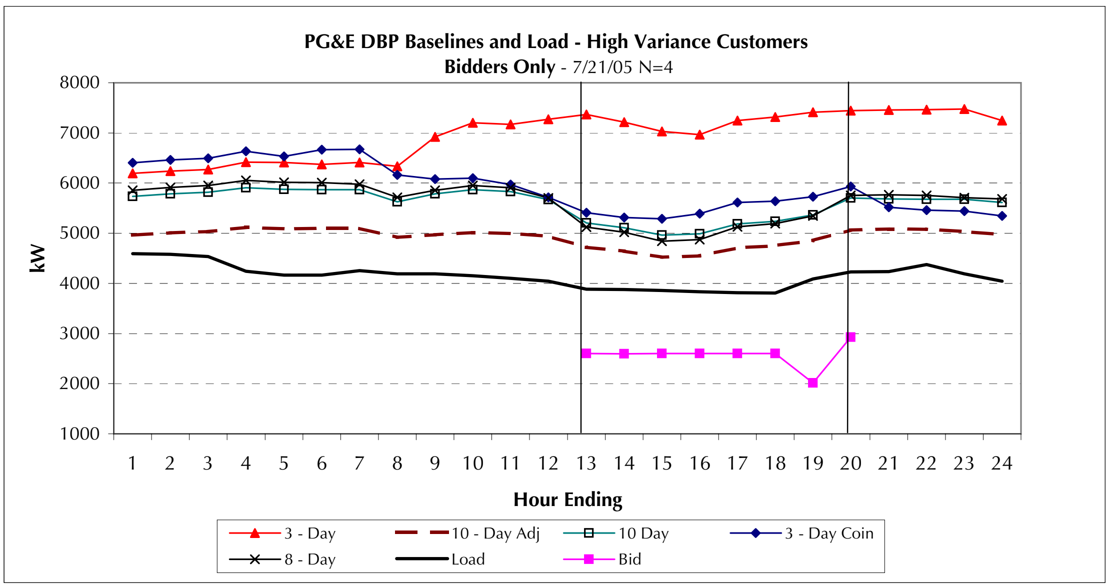


Exhibit D3-1 (Cont.)
PG&E DBP Event Day Baselines and Load





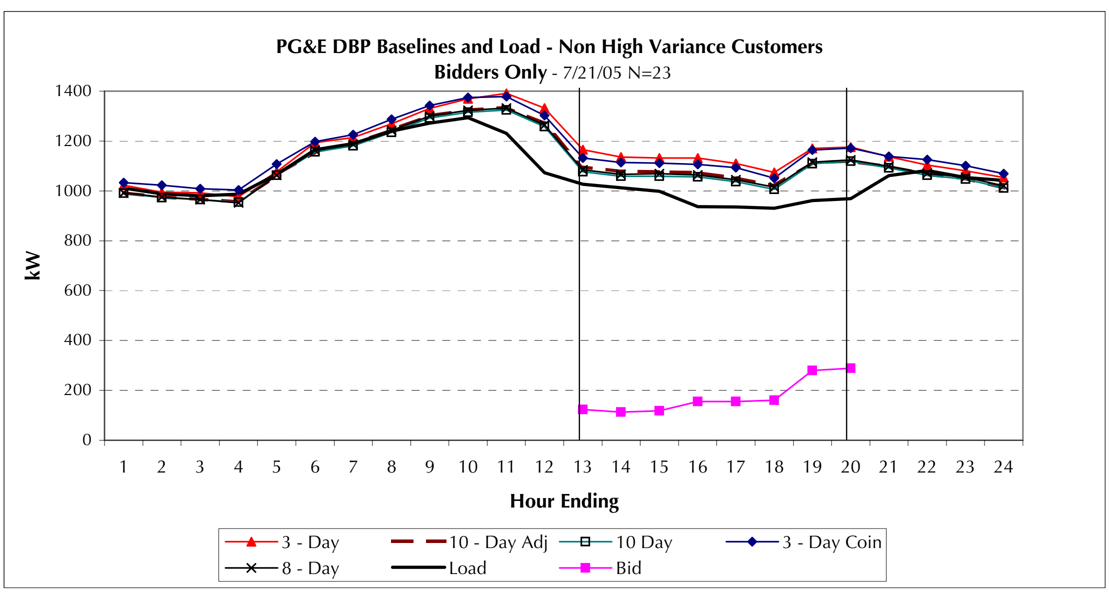
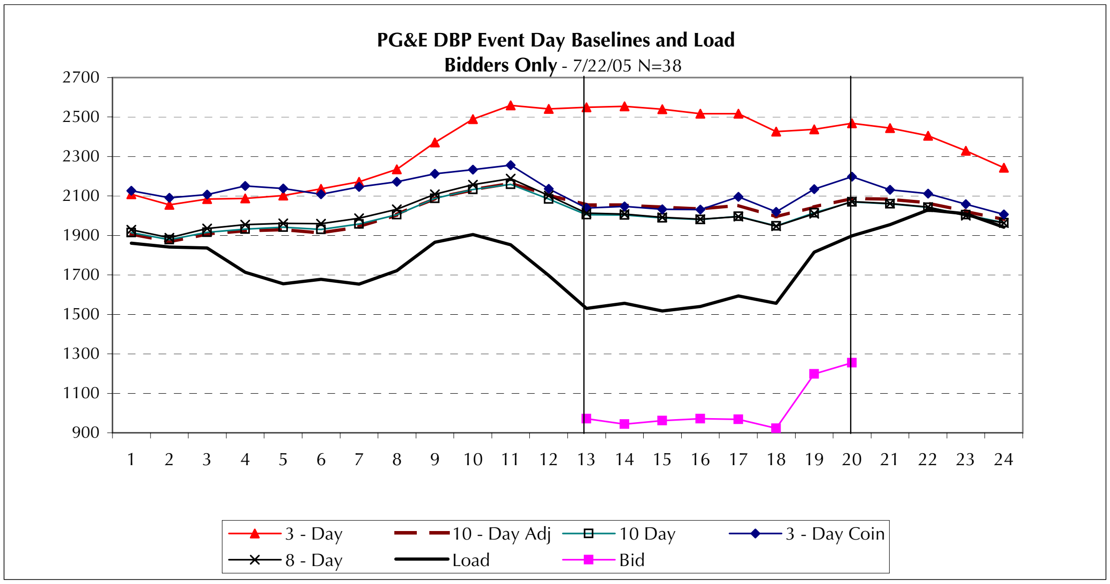
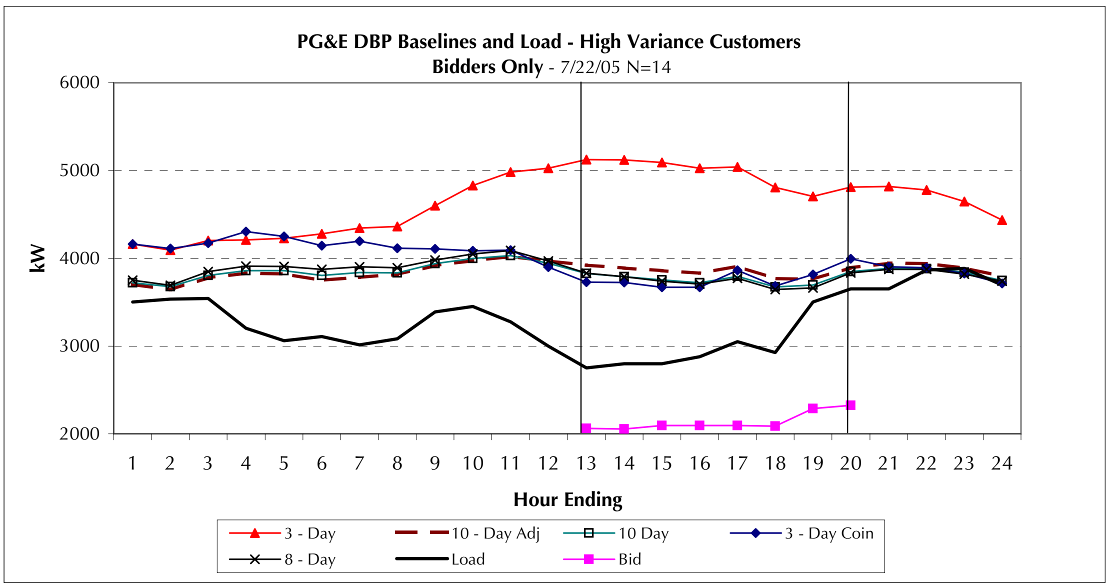


Exhibit D3-1 (Cont.)
PG&E DBP Event Day Baselines and Load





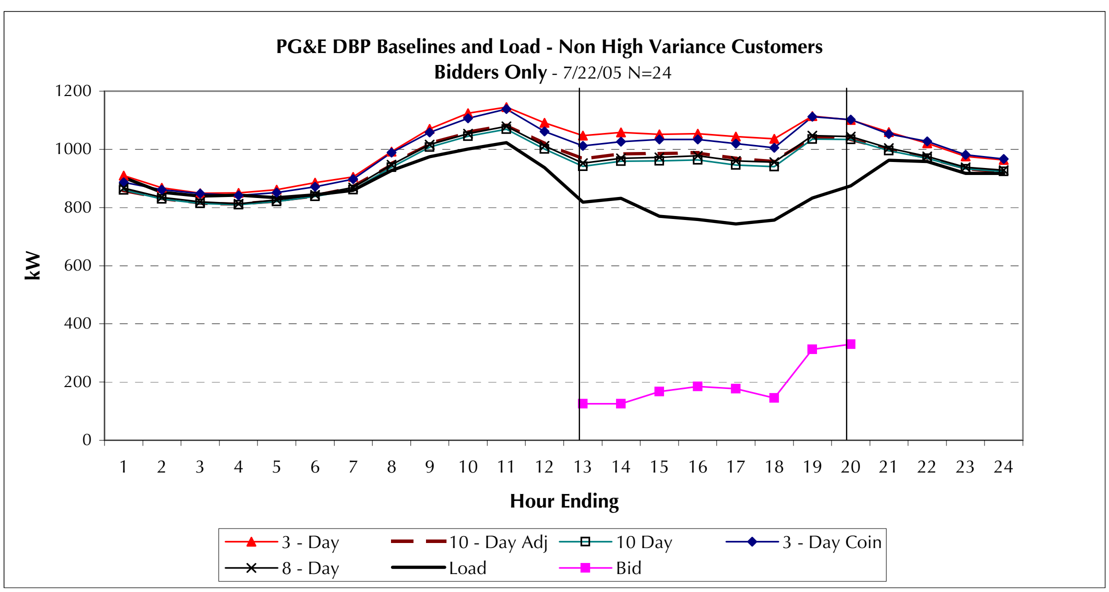
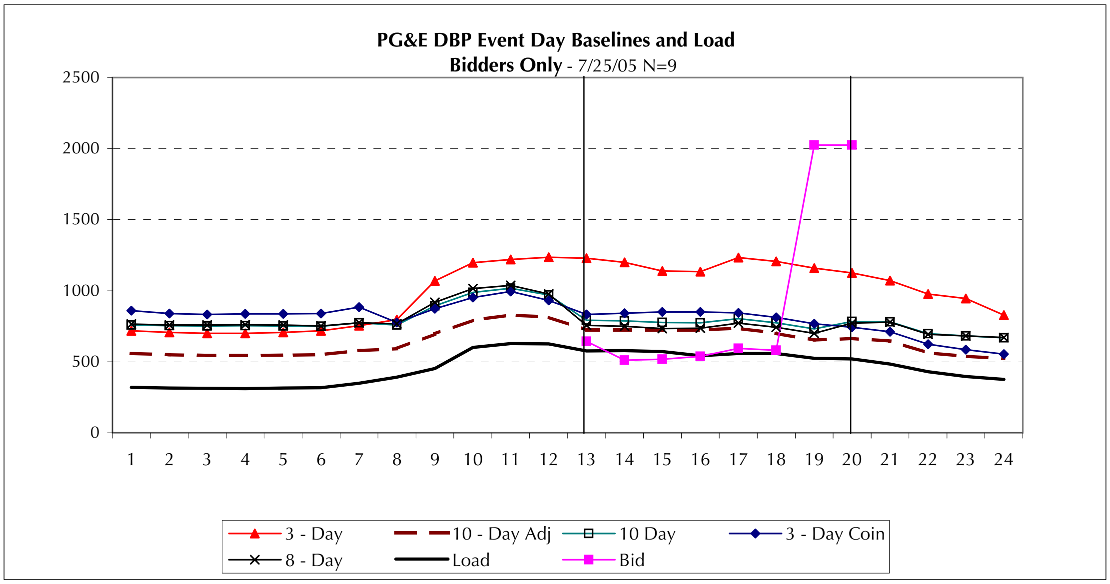
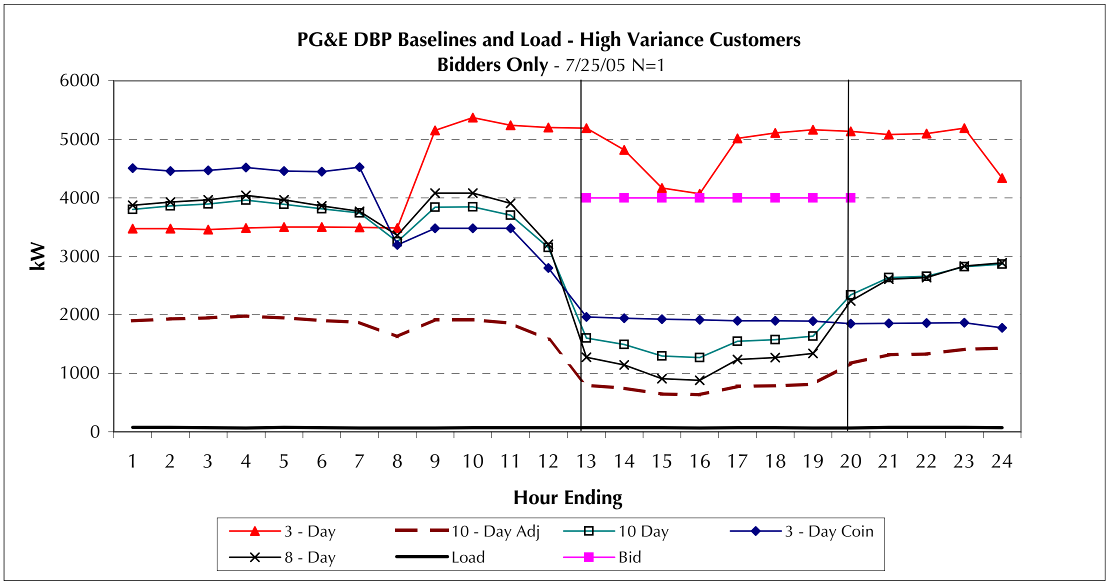


Exhibit D3-1 (Cont.)
PG&E DBP Event Day Baselines and Load





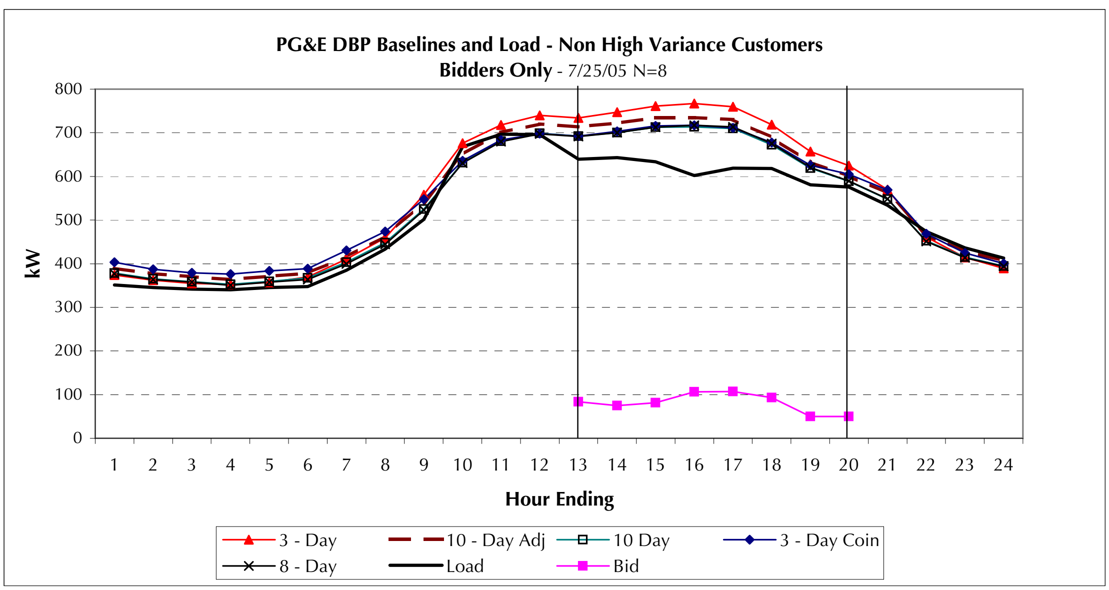
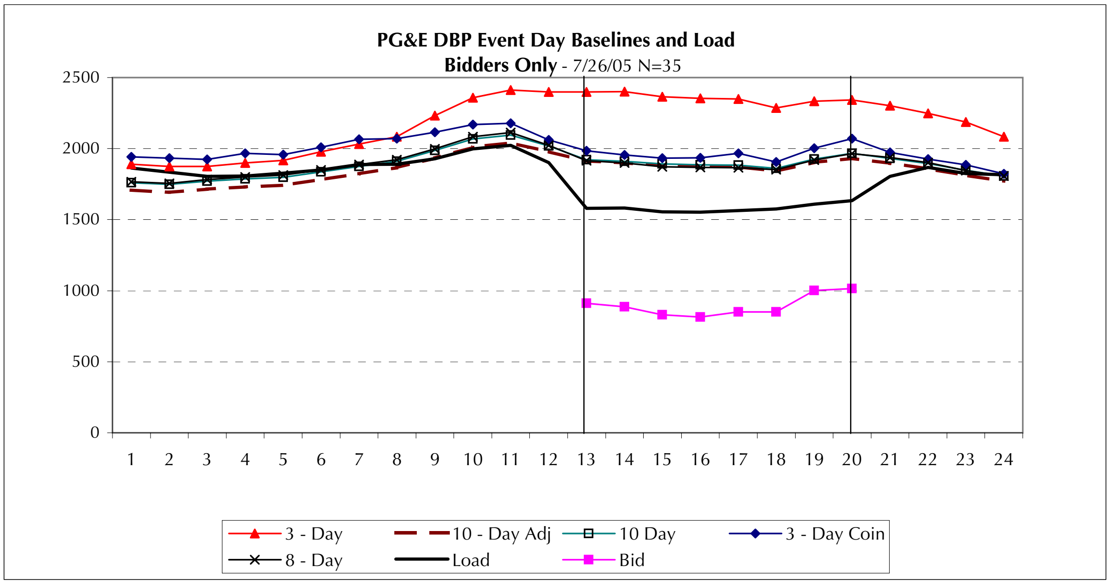
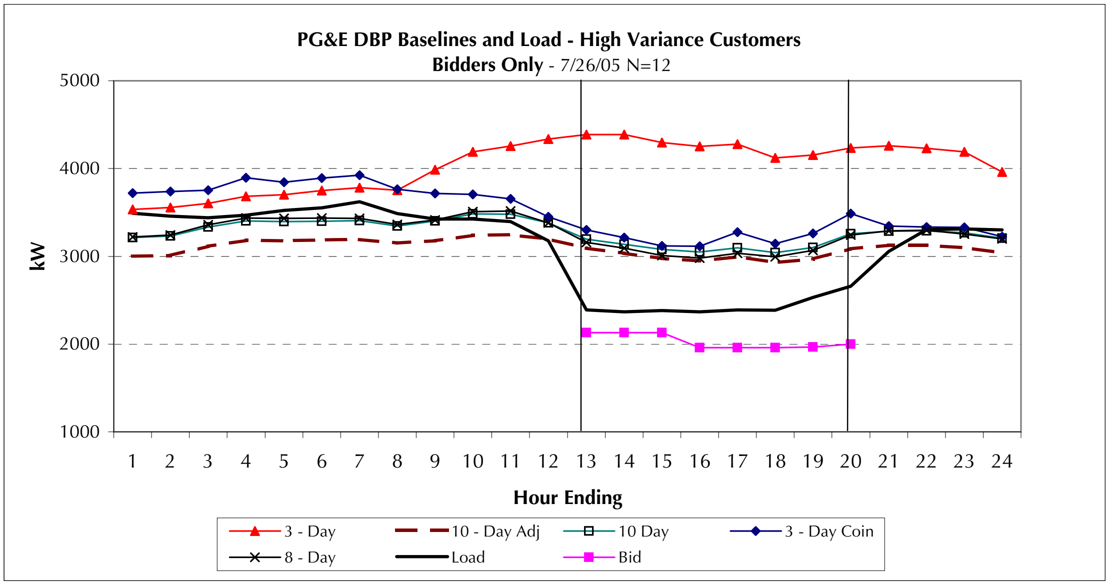


Exhibit D3-1 (Cont.)
PG&E DBP Event Day Baselines and Load





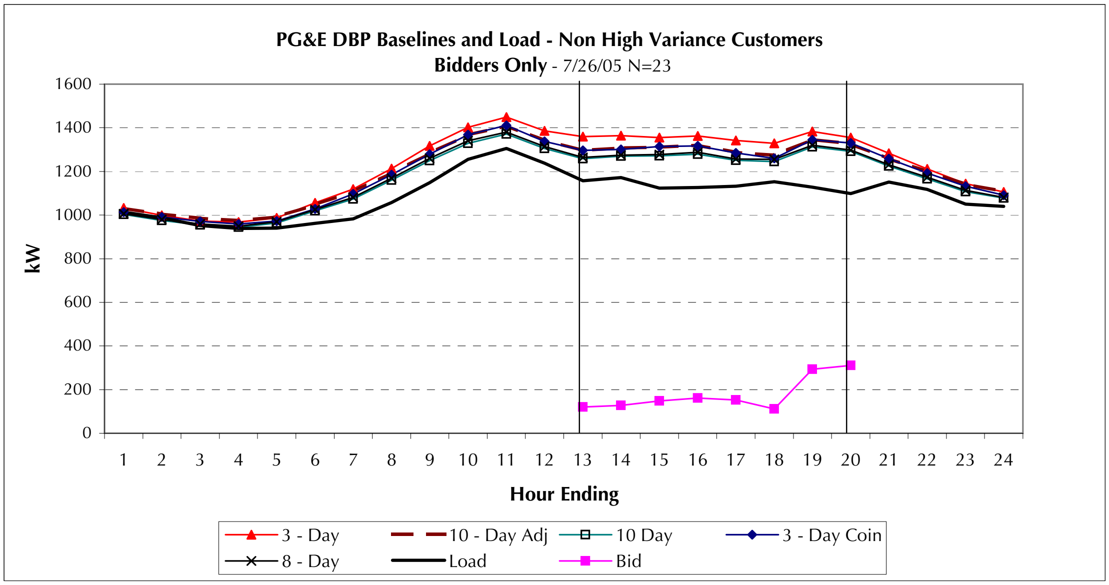
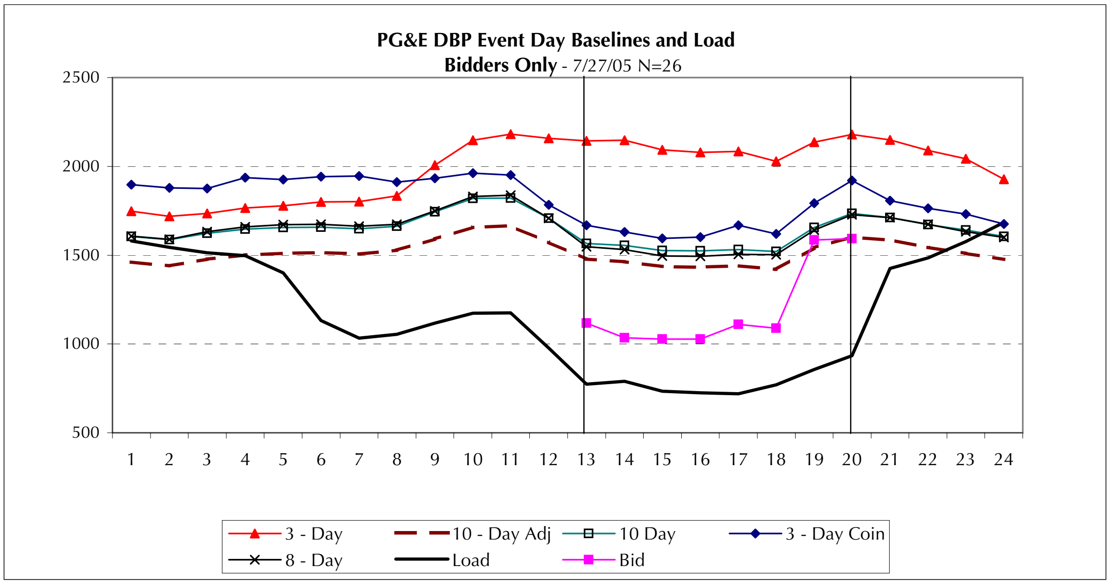
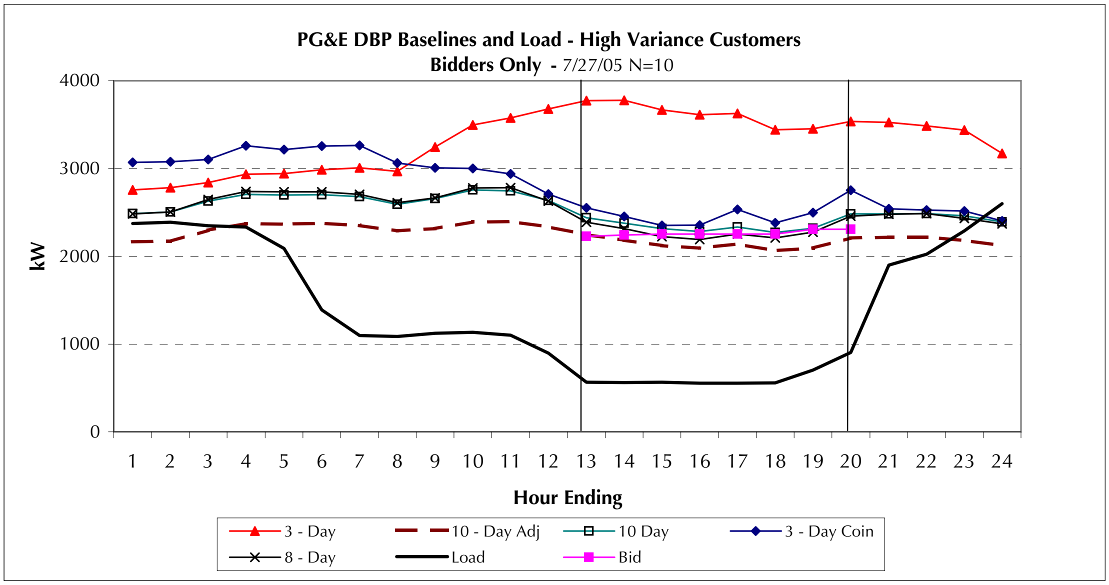


Exhibit D3-1 (Cont.)
PG&E DBP Event Day Baselines and Load





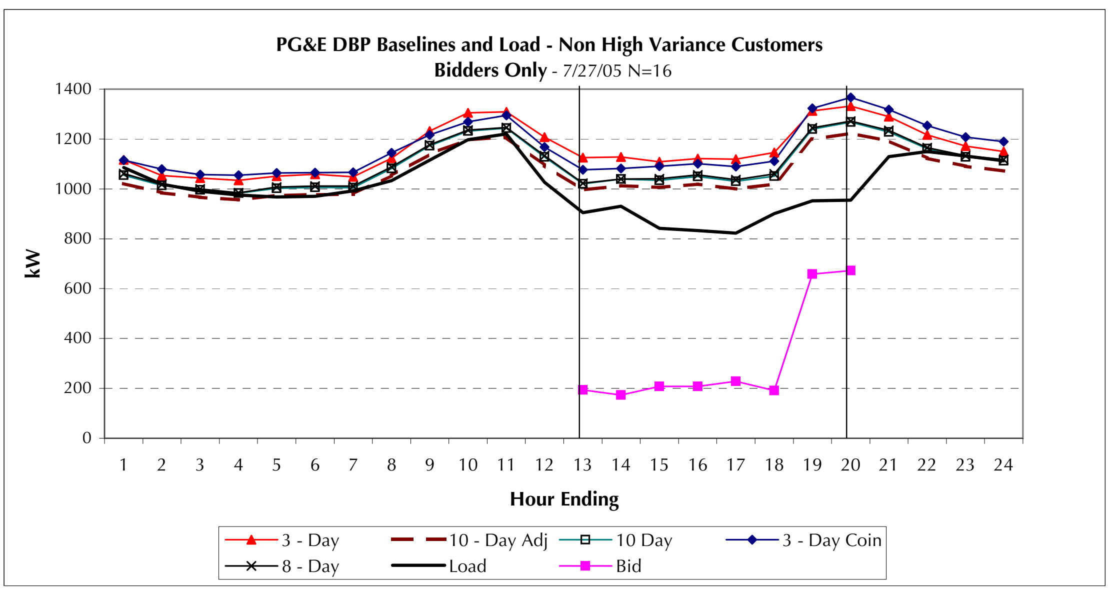
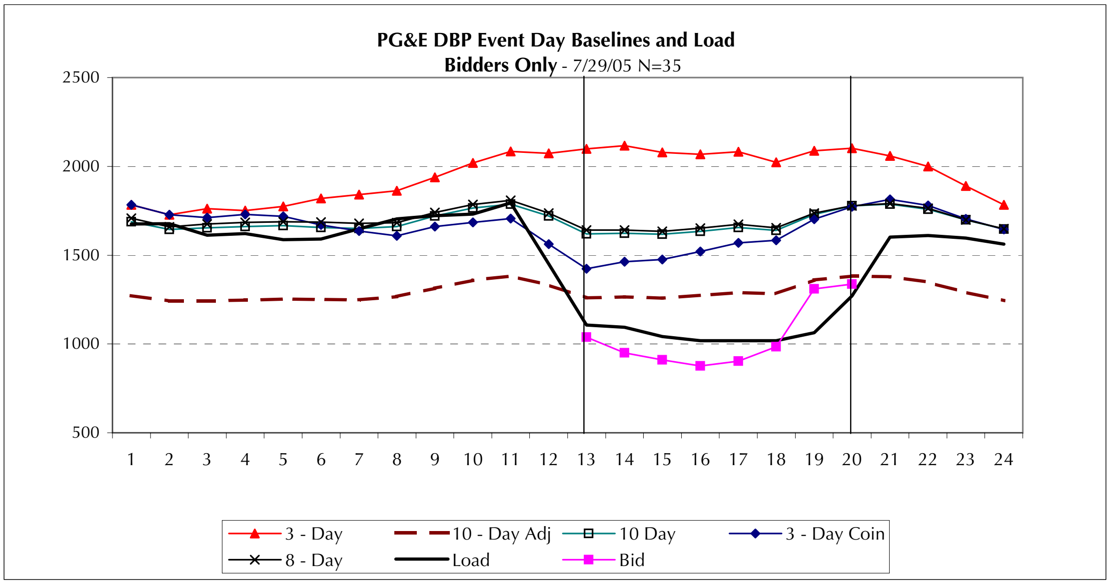
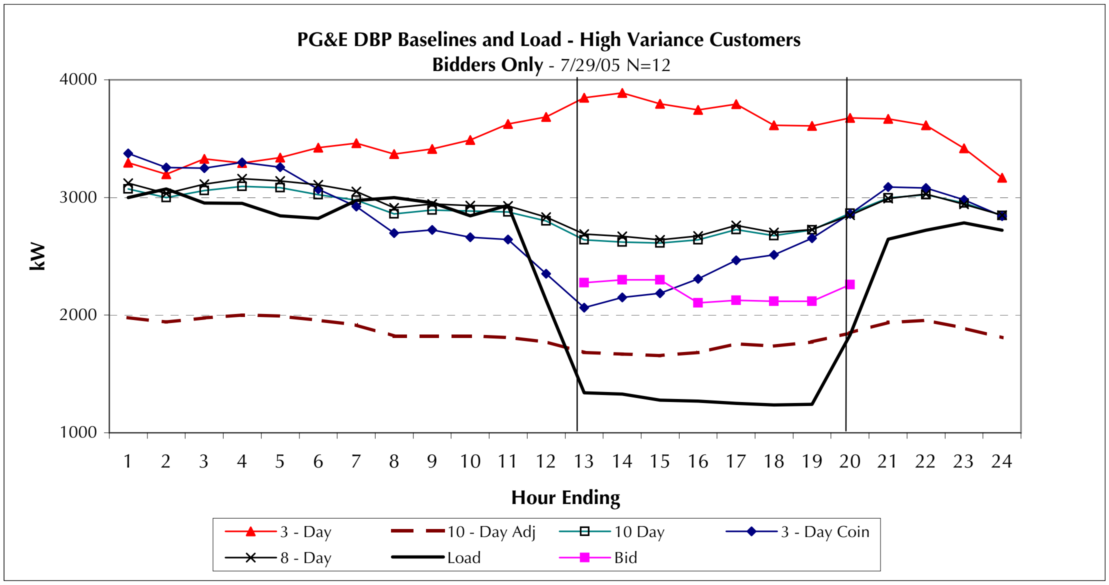


Exhibit D3-1 (Cont.)
PG&E DBP Event Day Baselines and Load





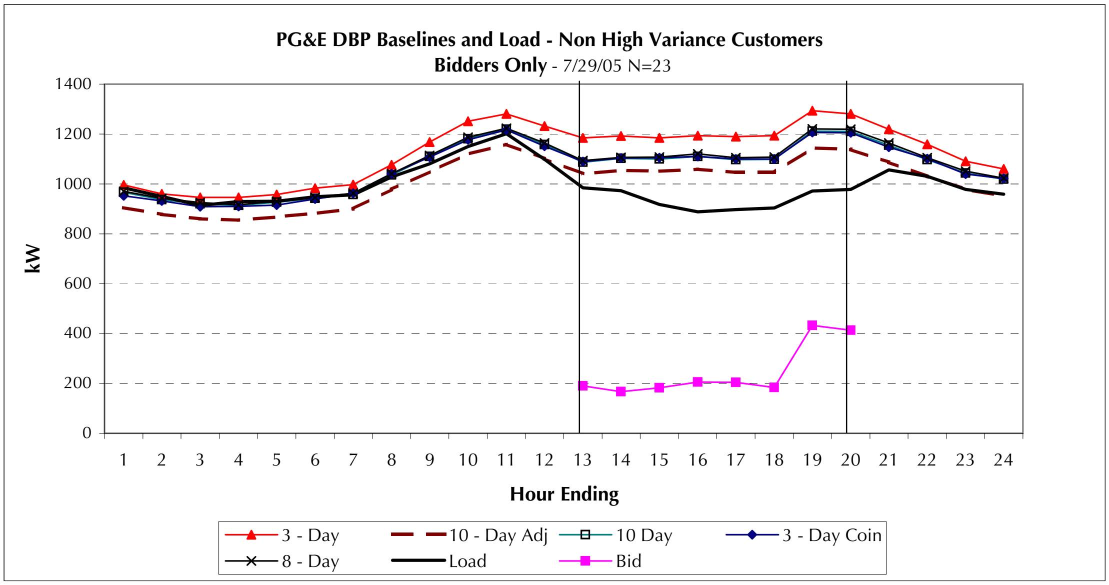
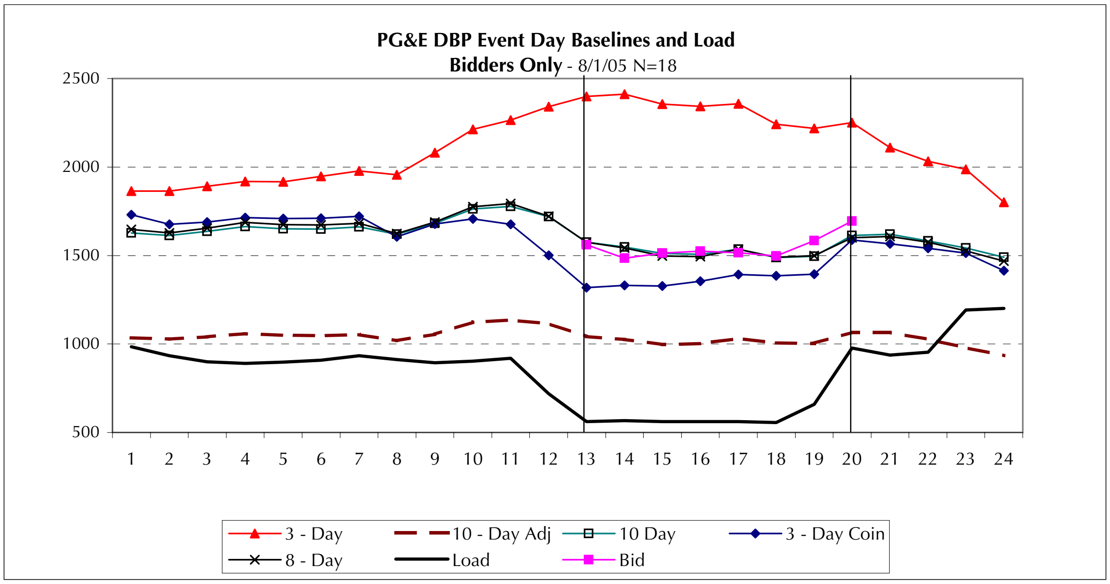
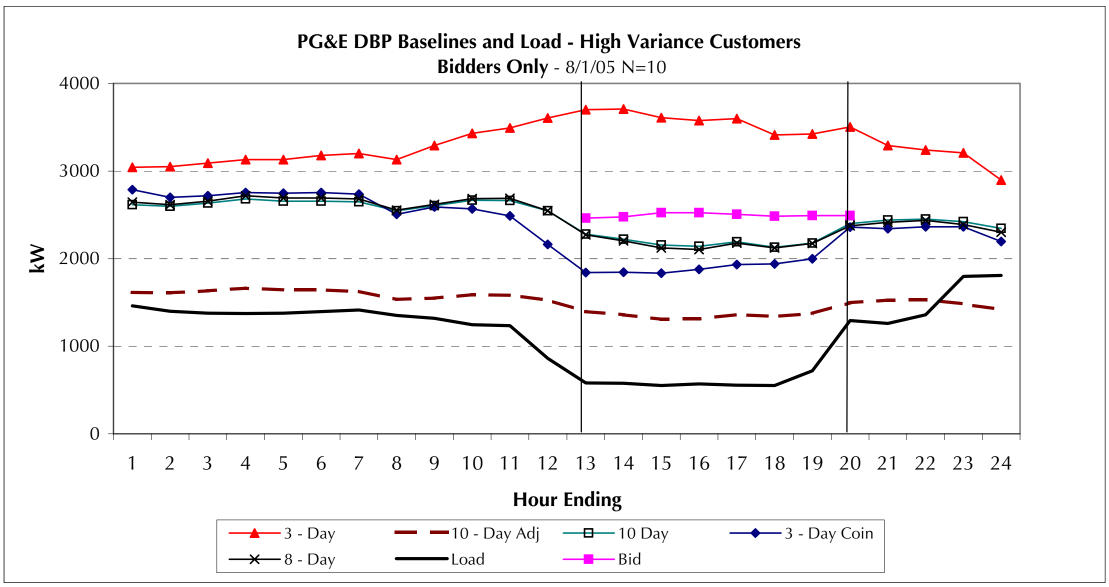


Exhibit D3-1 (Cont.)
PG&E DBP Event Day Baselines and Load





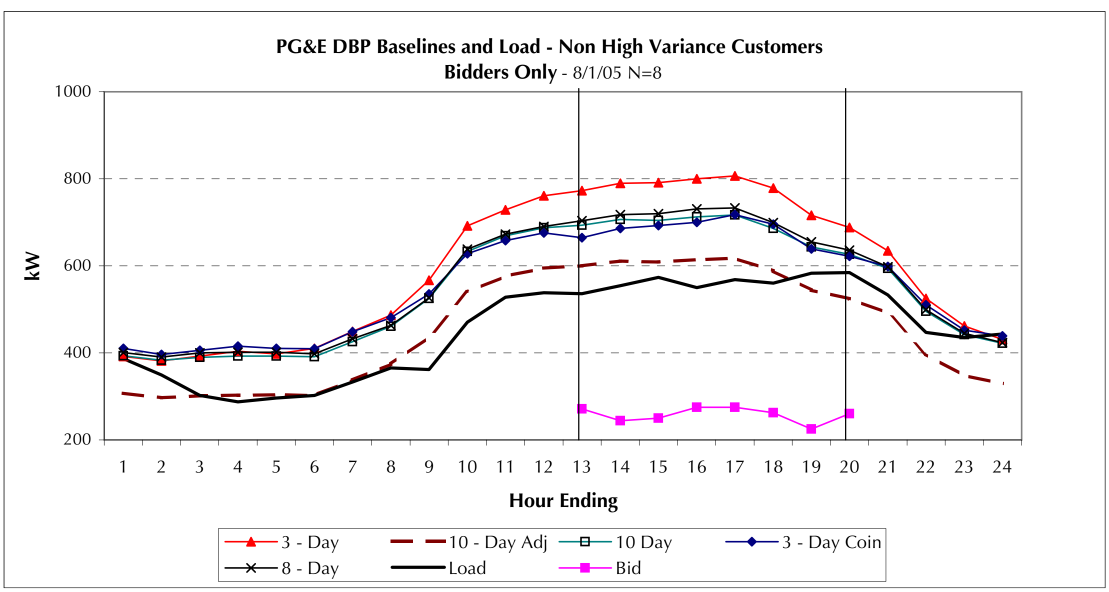
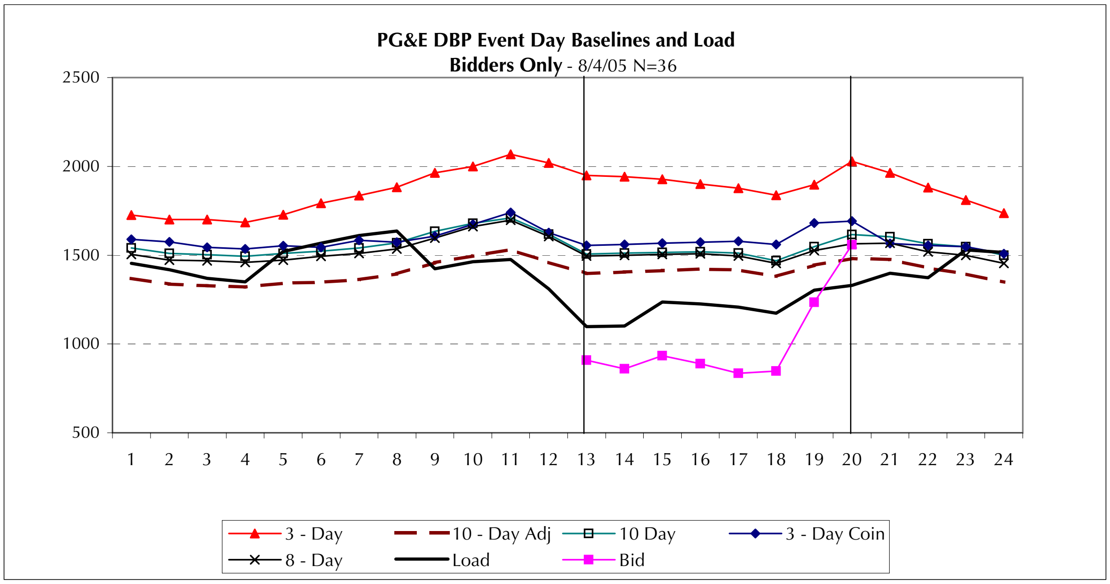
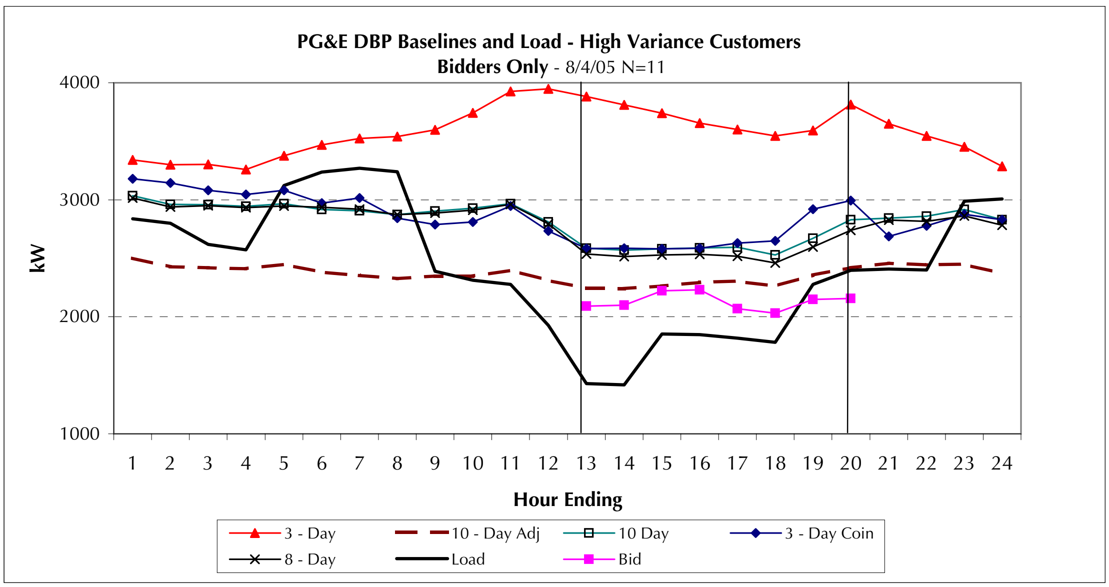
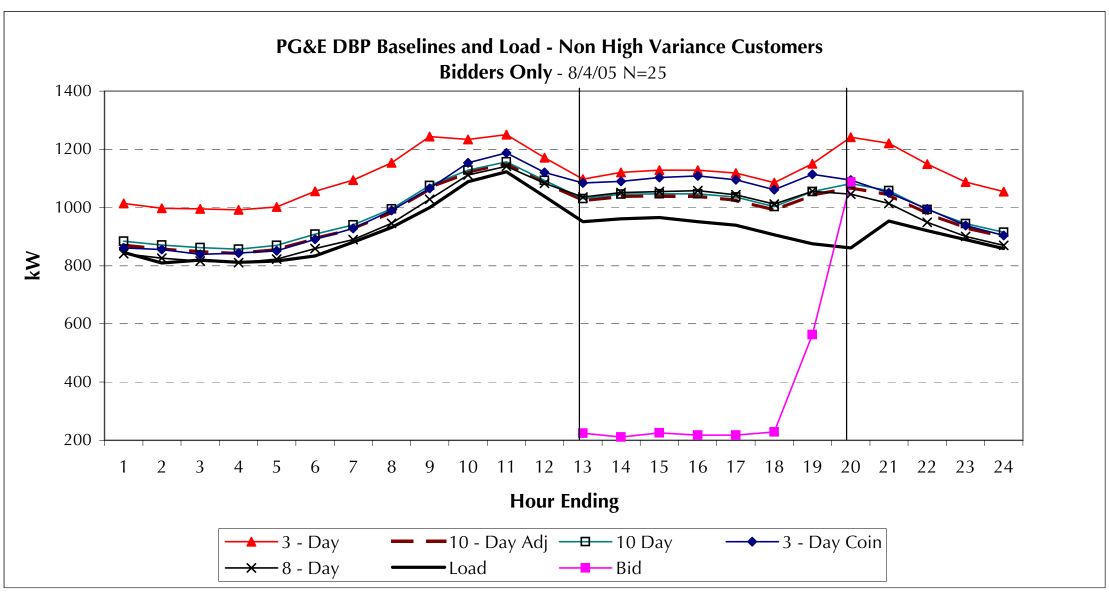
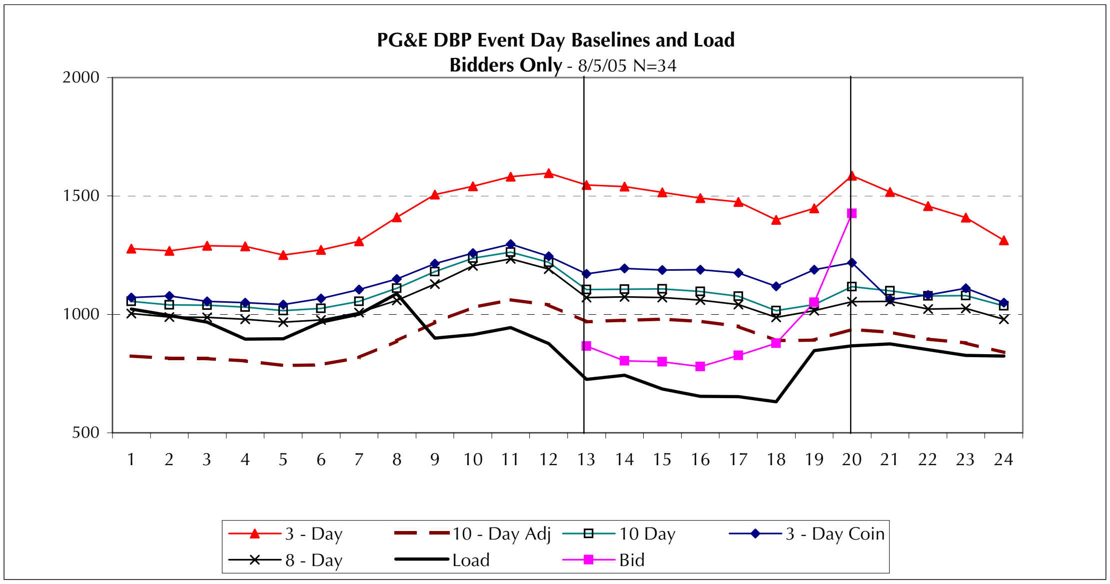


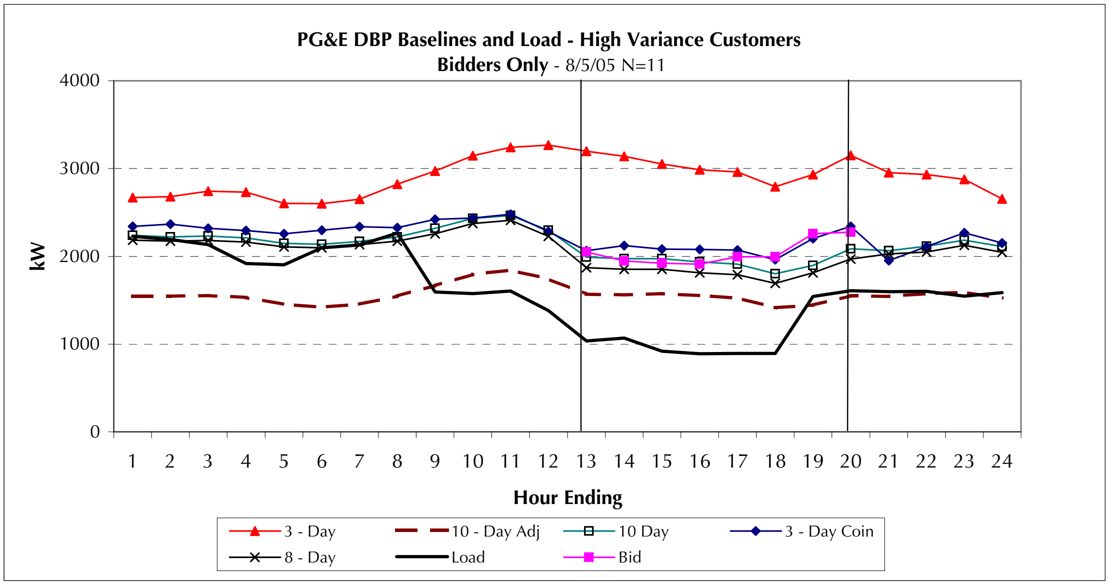
Exhibit D3-1 (Cont.)
PG&E DBP Event Day Baselines and Load








PG&E DBP Event Day Baselines and Load
Bidders Only - 8/5/05 N=34
2000
1500
1000
500
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
3 - Day
10 - Day Adj
10 Day
3 - Day Coin
8 - Day
Load
Bid


PG&E DBP Baselines and Load - High Variance Customers
Bidders Only - 8/5/05 N=11
kW
4000
3000
2000
1000
0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour Ending
3 - Day
10 - Day Adj
10 Day
3 - Day Coin
8 - Day
Load
Bid

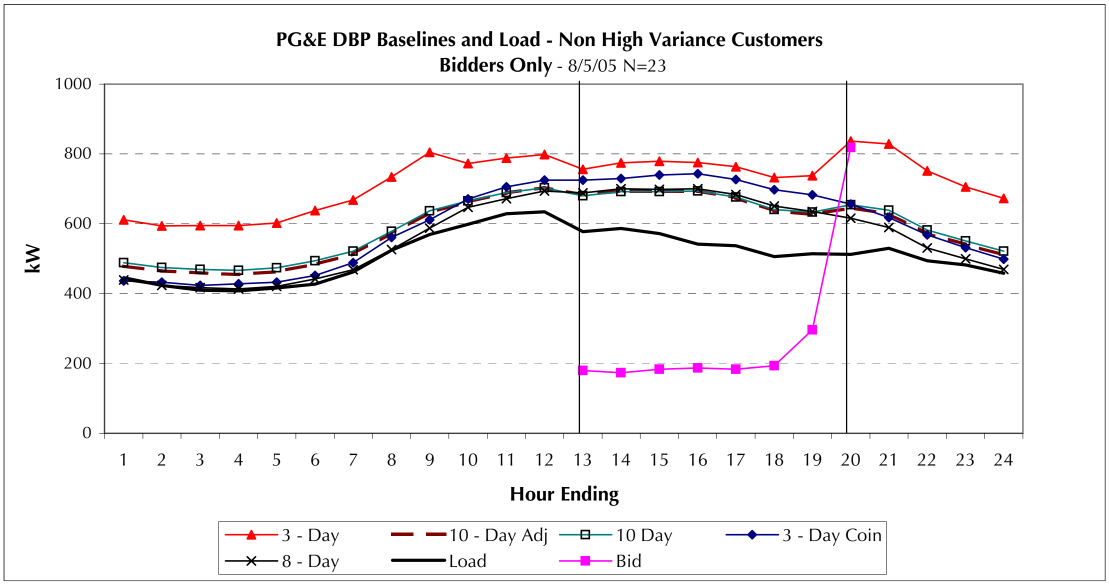
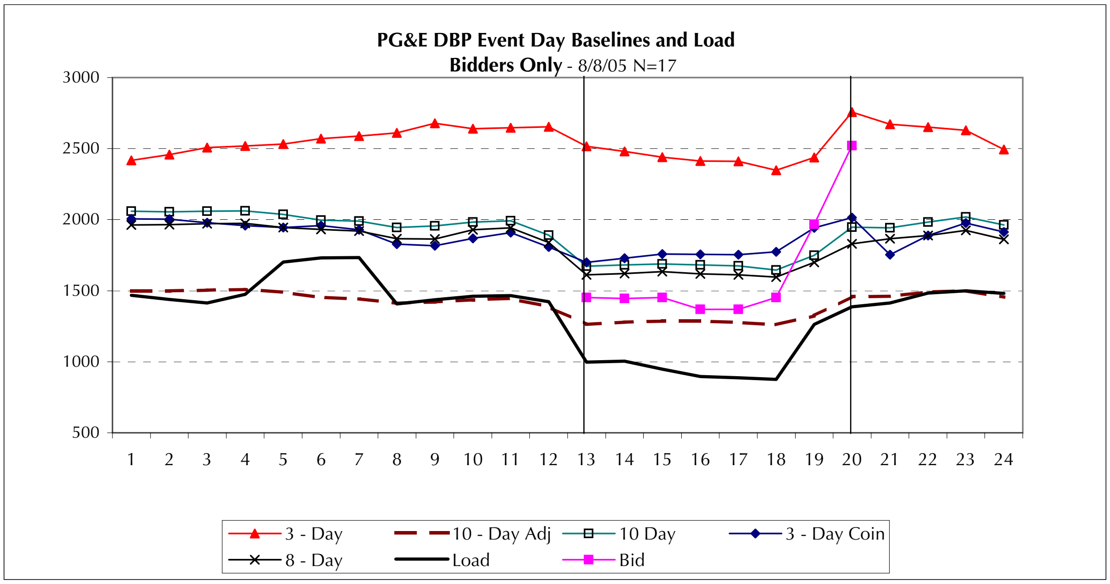
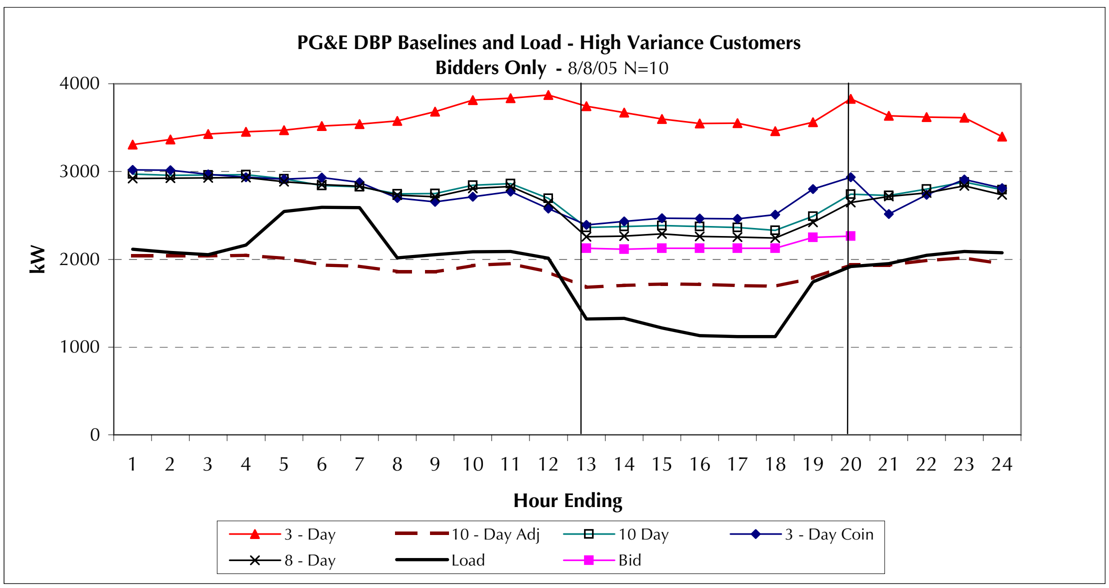

PG&E DBP Baselines and Load - Non High Variance Customers
Bidders Only - 8/5/05 N=23
kW
1000
800
600
400
200
0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour Ending
3 - Day
10 - Day Adj
10 Day
3 - Day Coin
8 - Day
Load
Bid

Exhibit D3-1 (Cont.)
PG&E DBP Event Day Baselines and Load





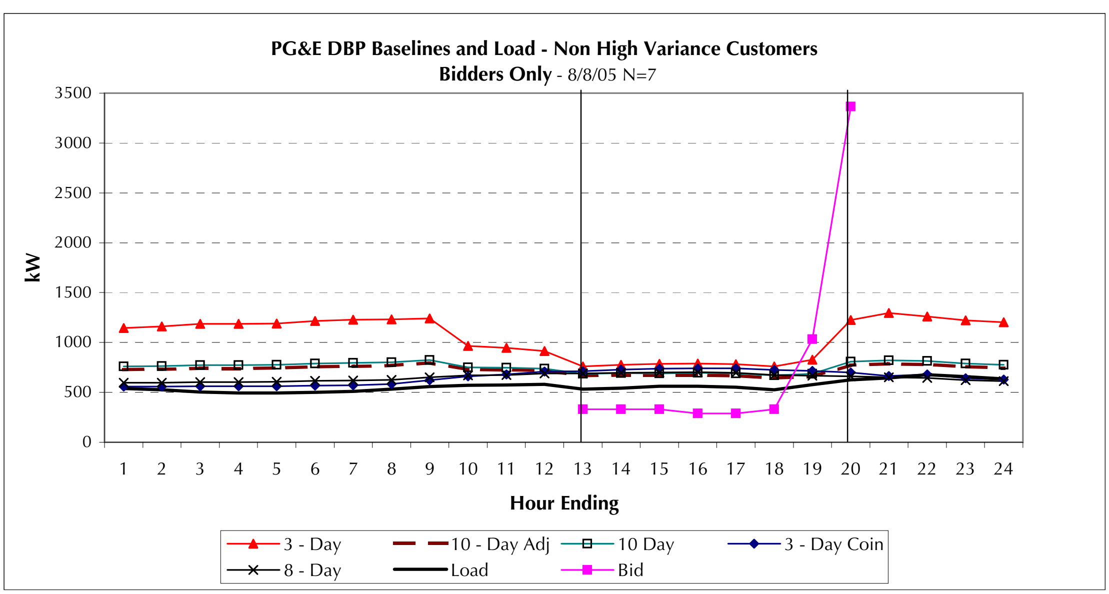
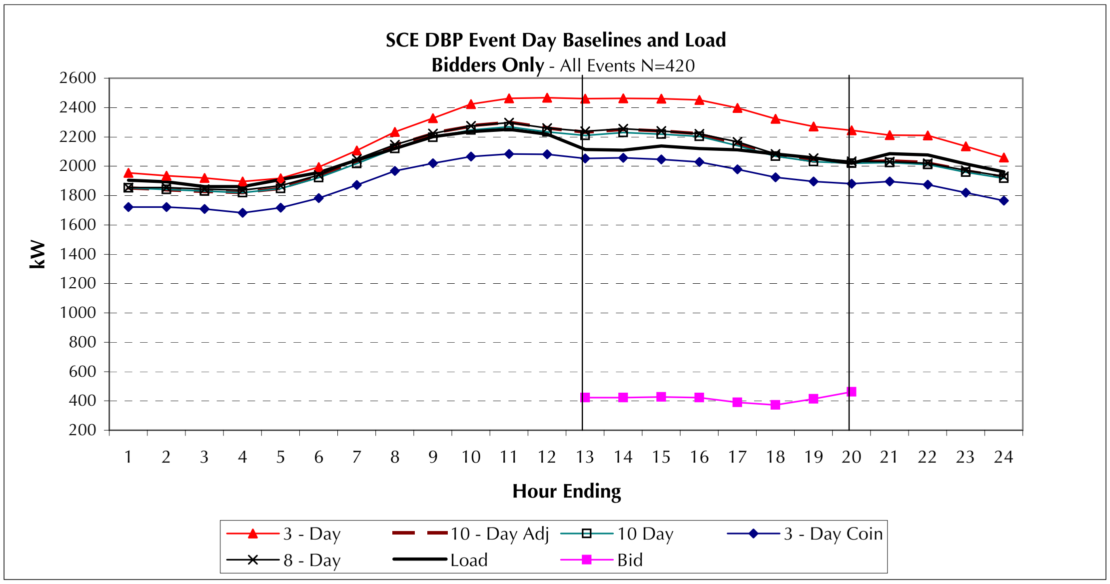
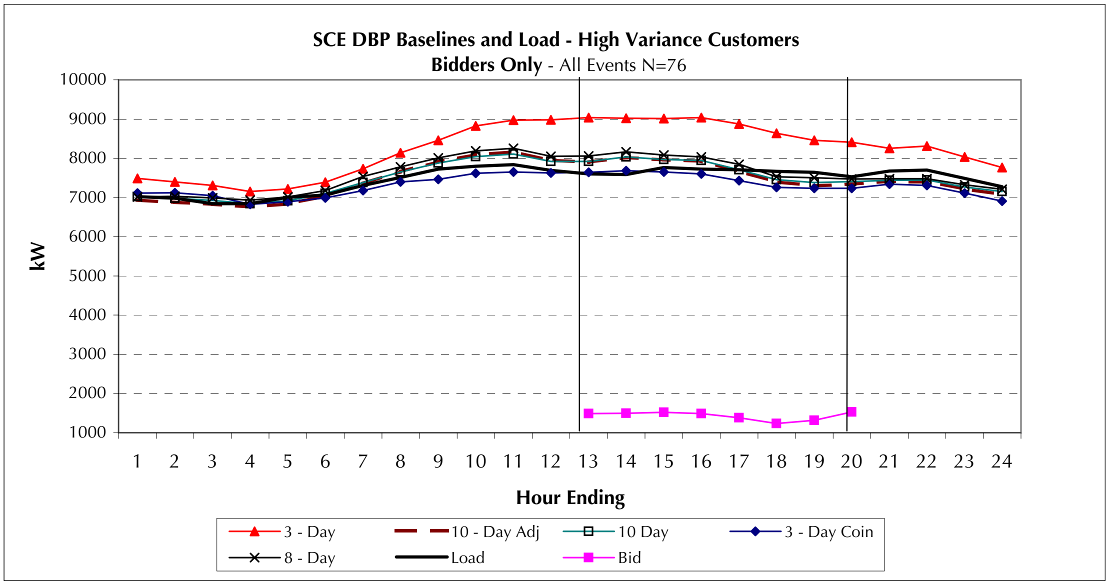


Exhibit D3-2
SCE DBP Event Day Baselines and Load





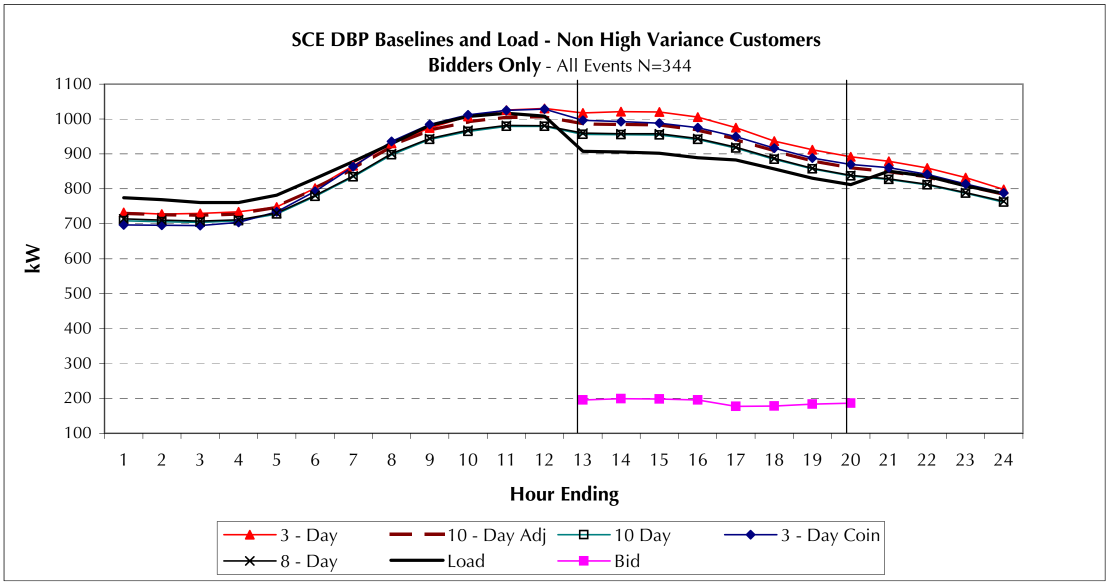
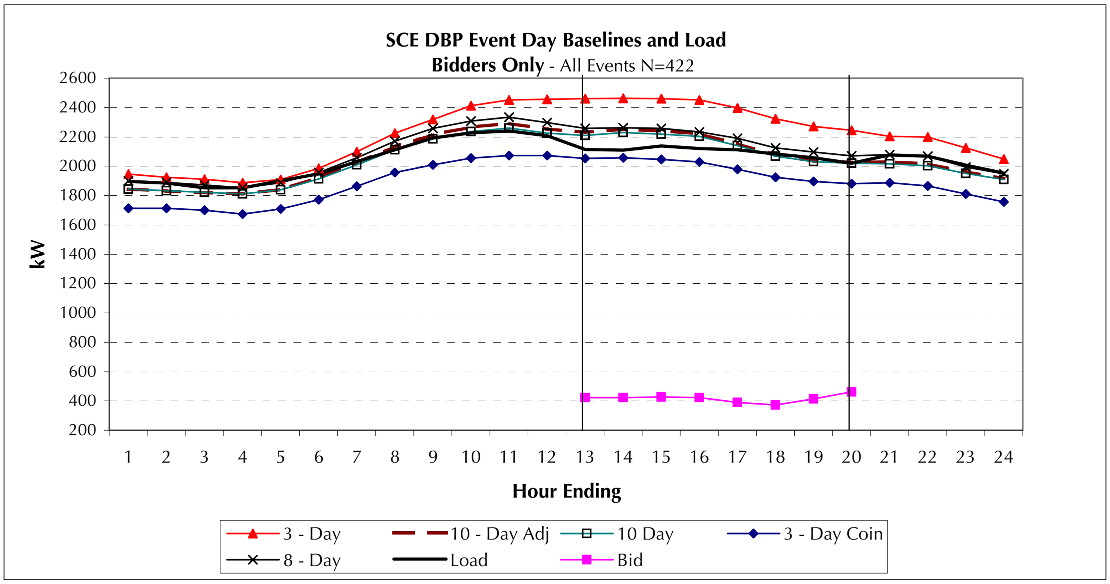
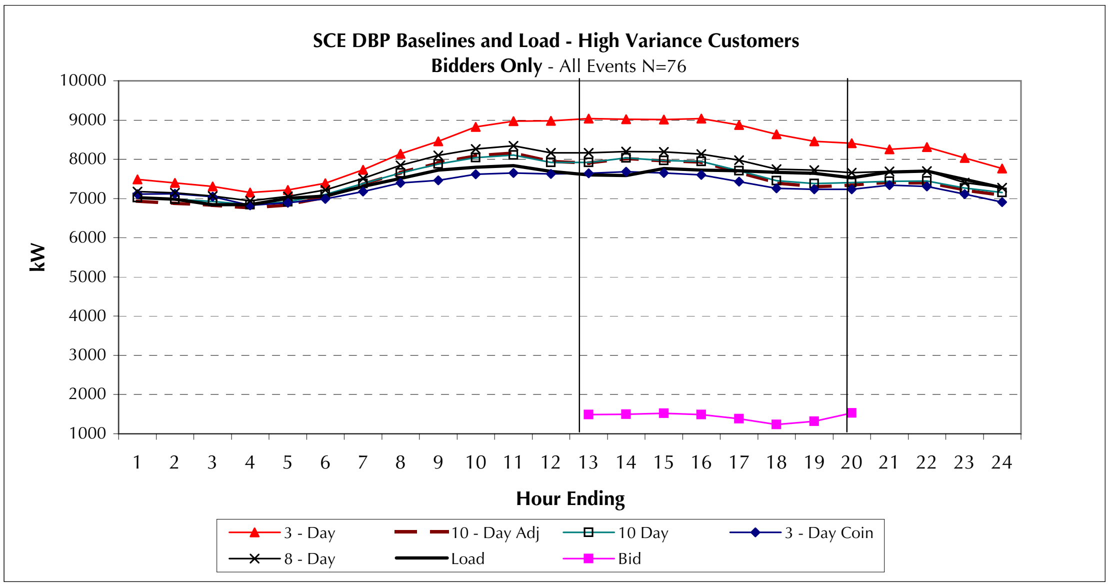


Exhibit D3-2 (Cont.)
SCE DBP Event Day Baselines and Load





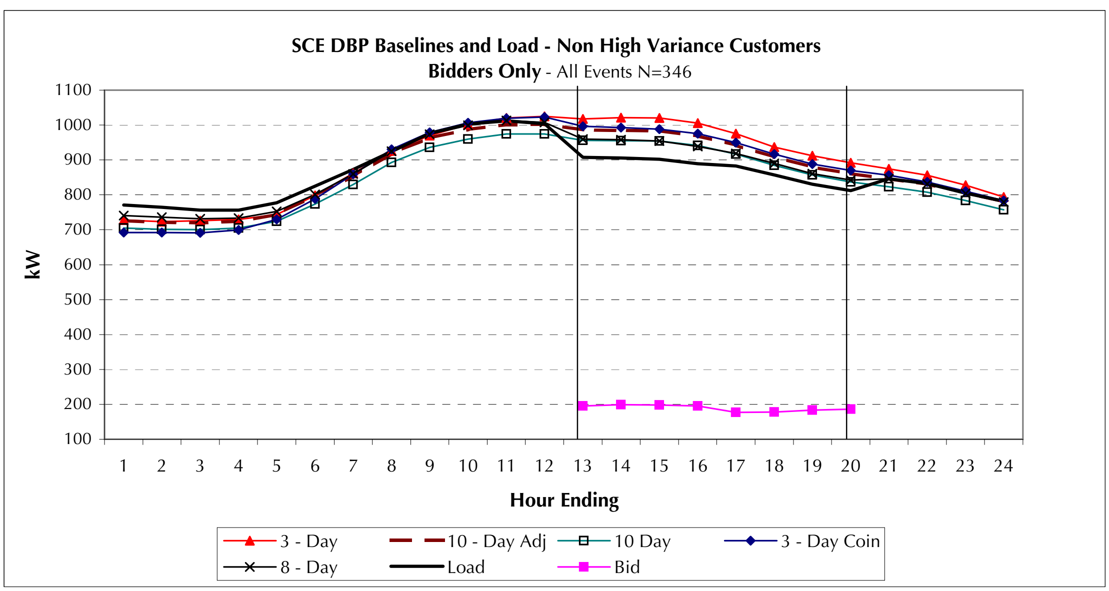
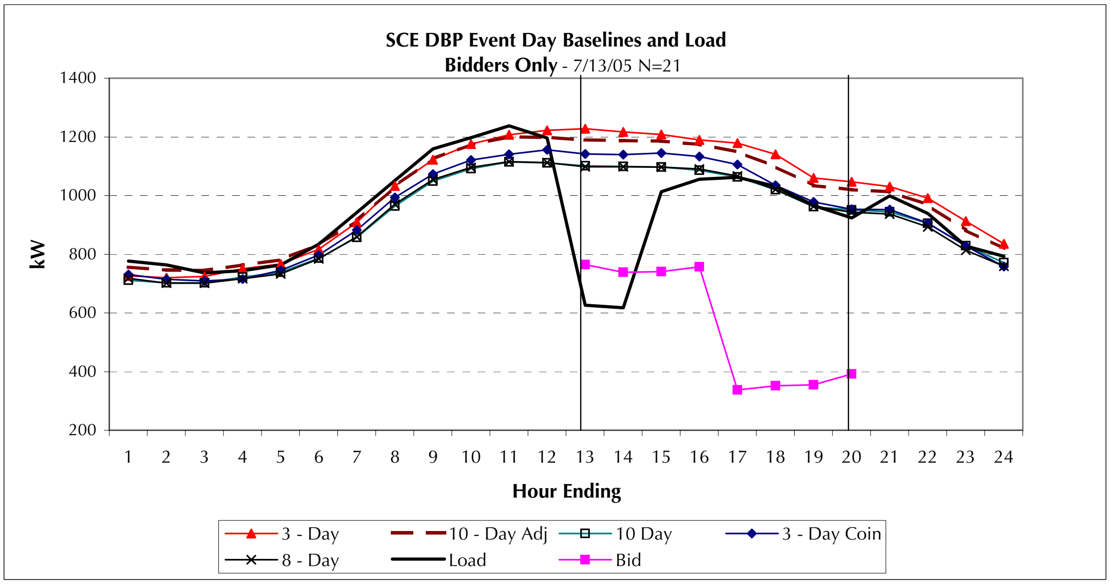
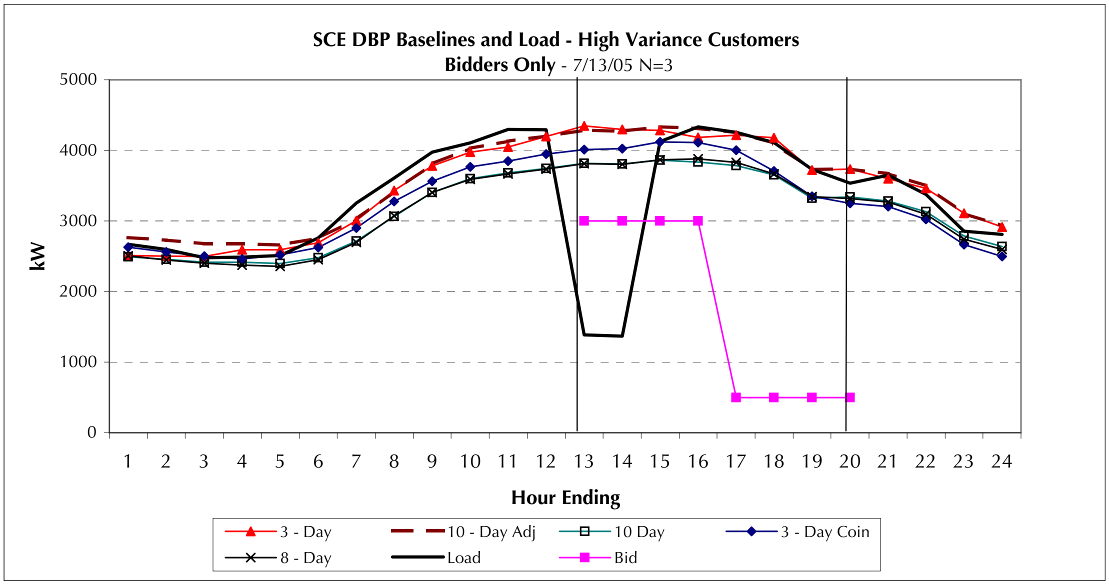


Exhibit D3-2 (Cont.)
SCE DBP Event Day Baselines and Load





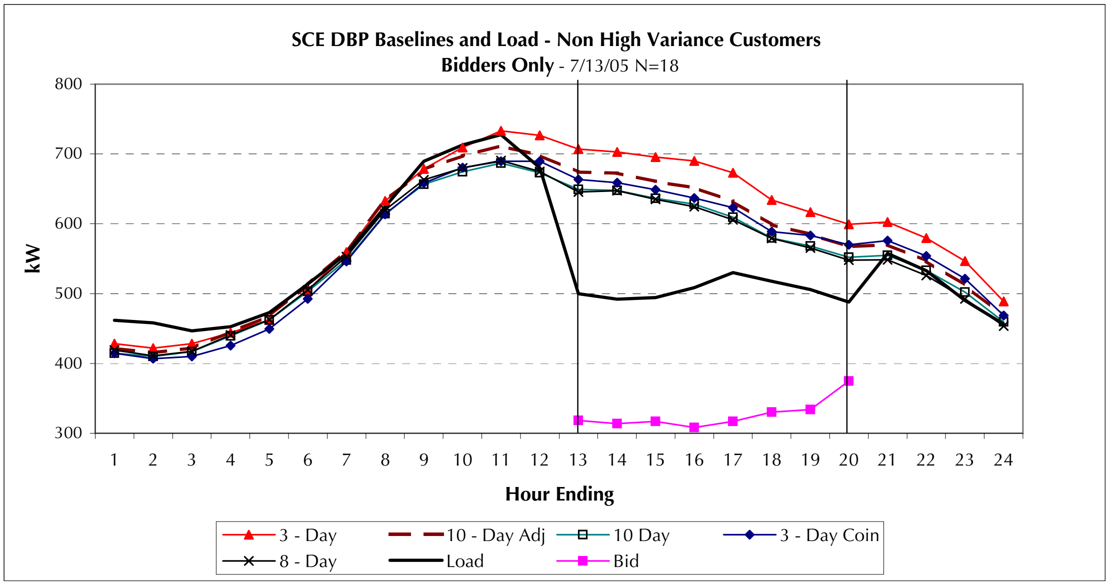
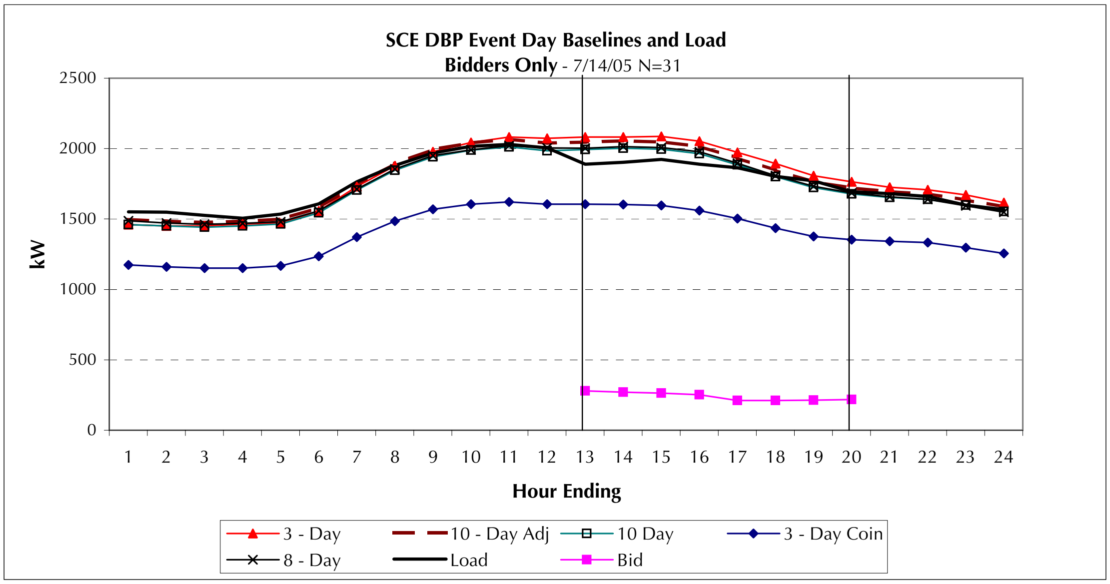
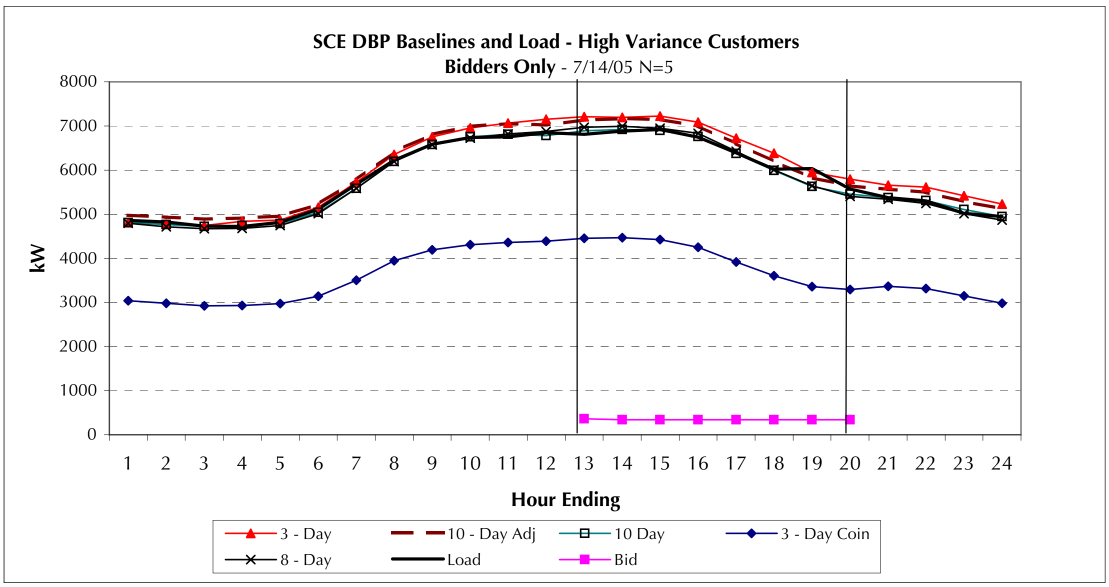


Exhibit D3-2 (Cont.)
SCE DBP Event Day Baselines and Load





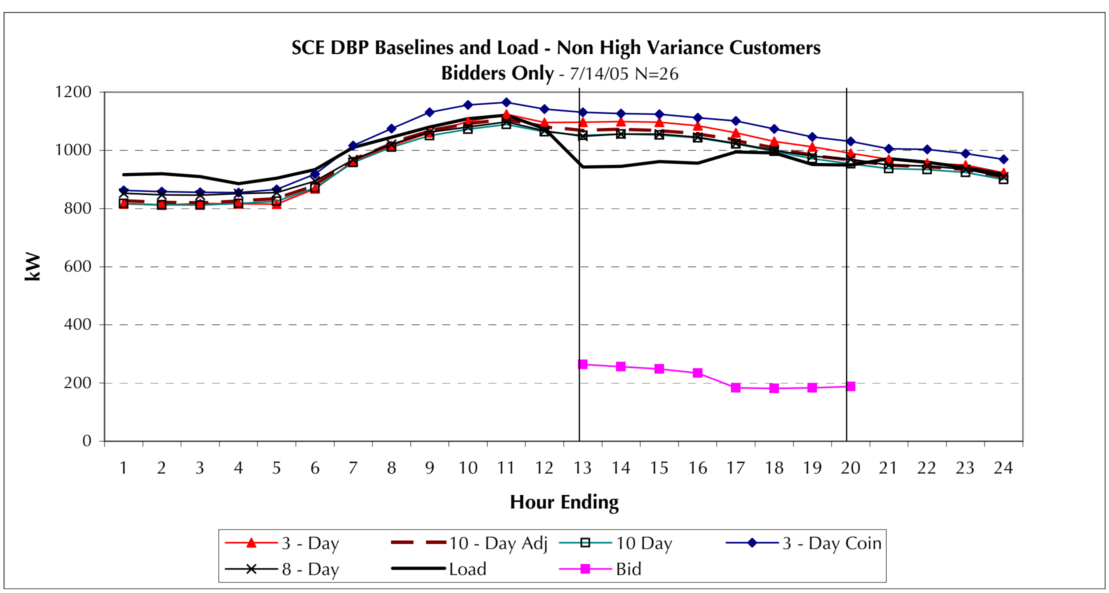
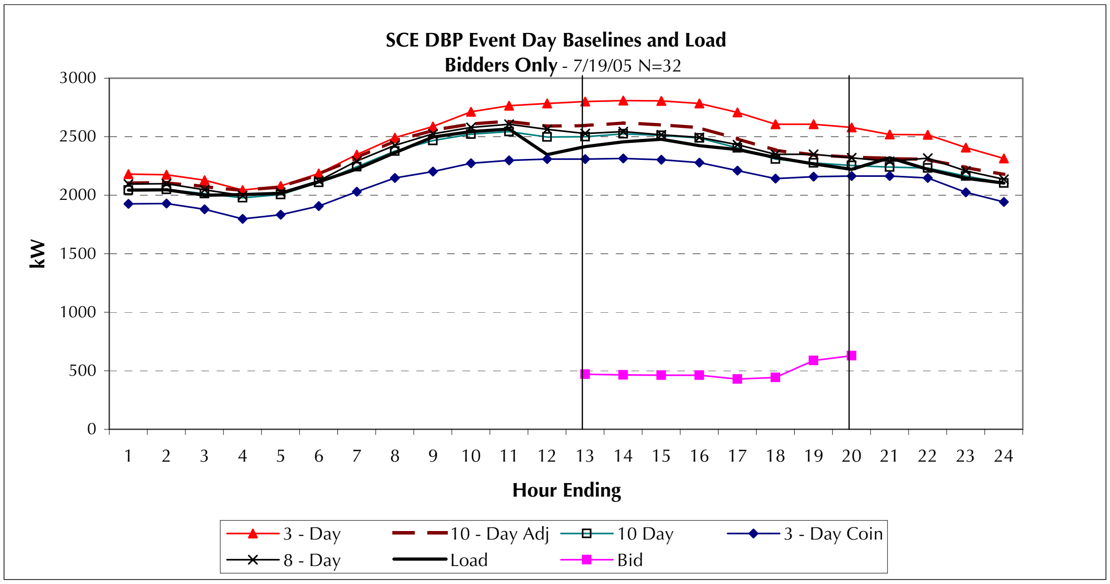
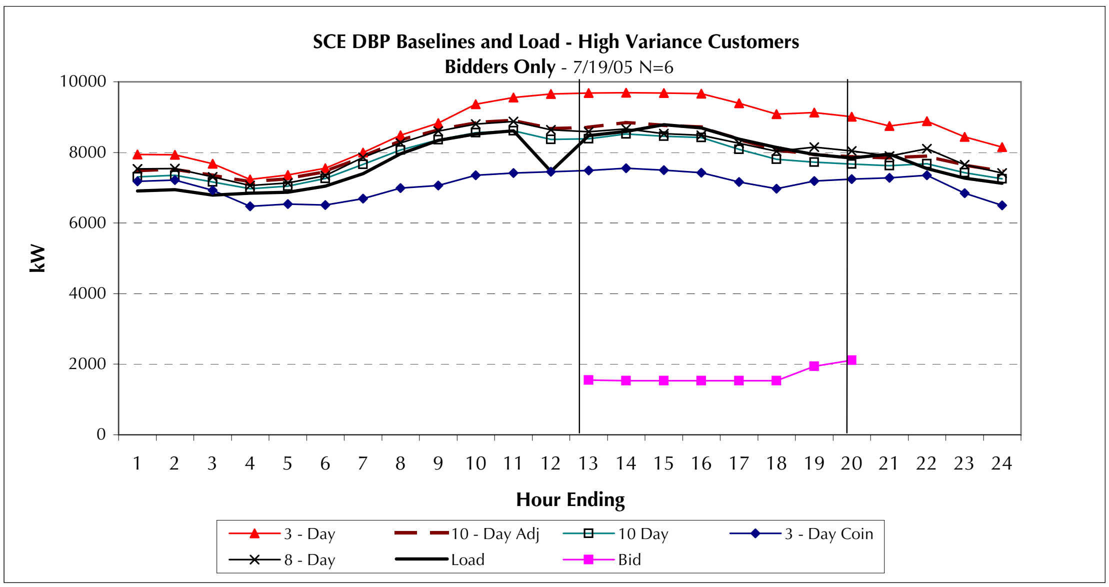
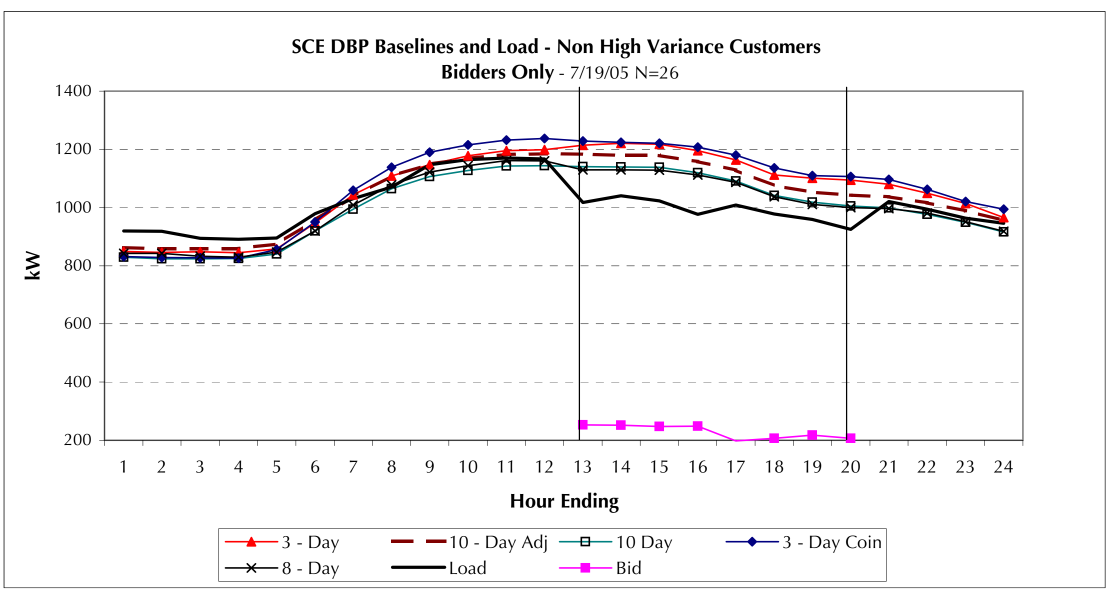


Exhibit D3-2 (Cont.)
SCE DBP Event Day Baselines and Load







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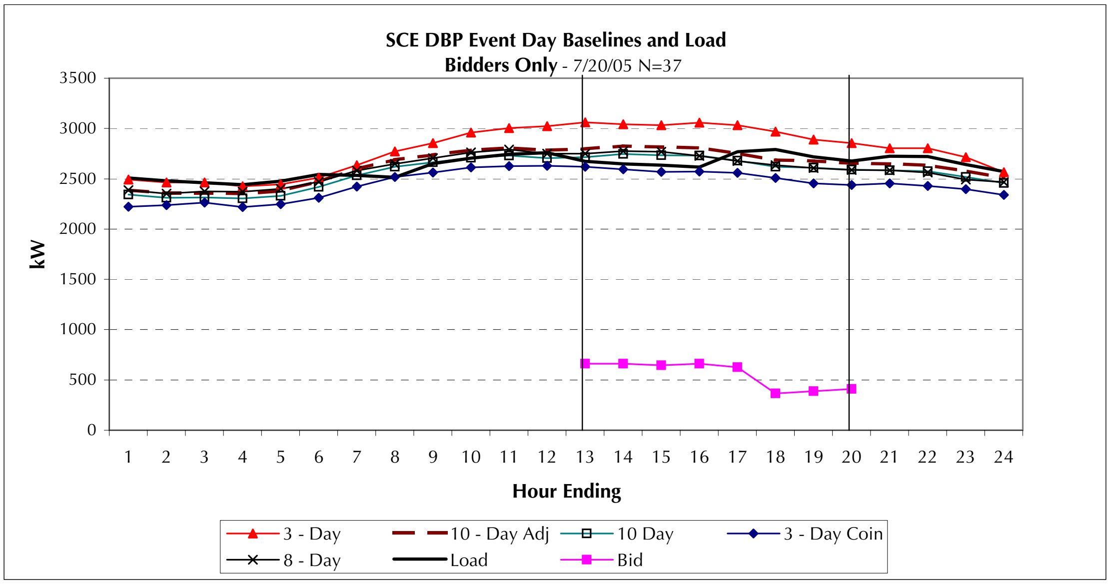
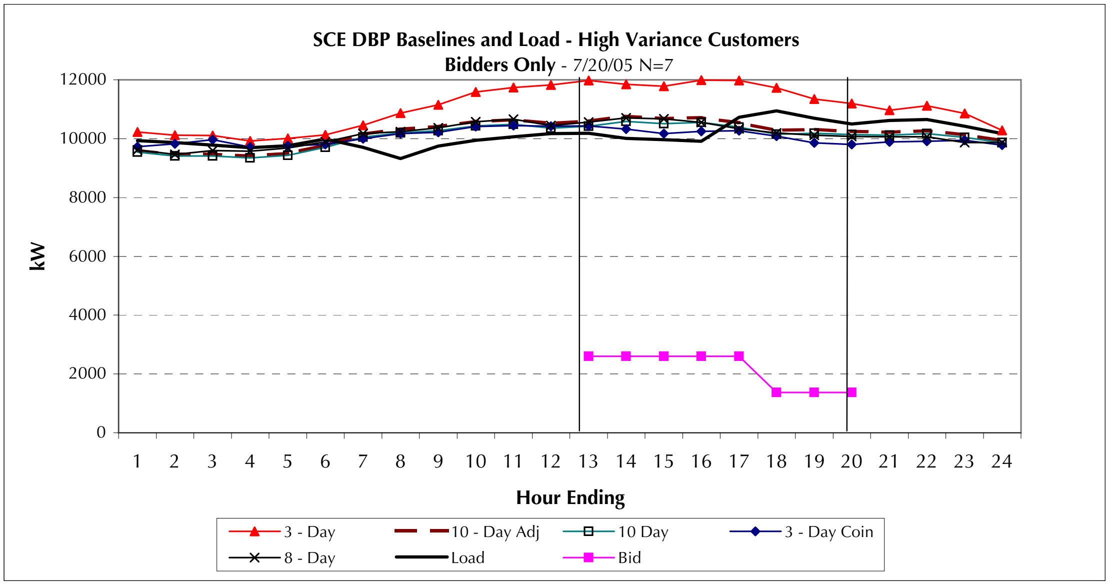
SCE DBP Event Day Baselines and Load





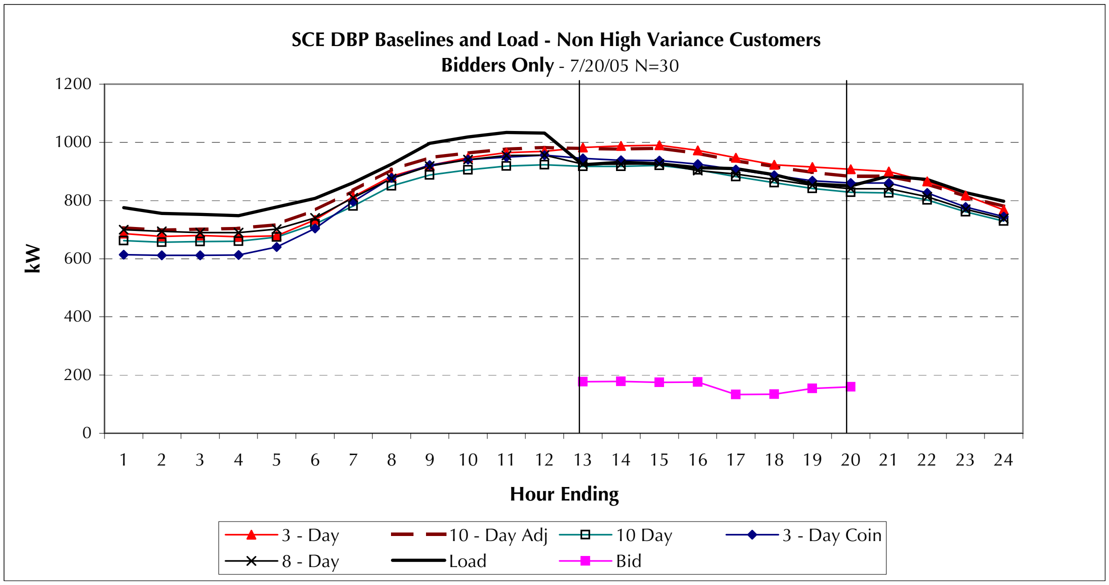
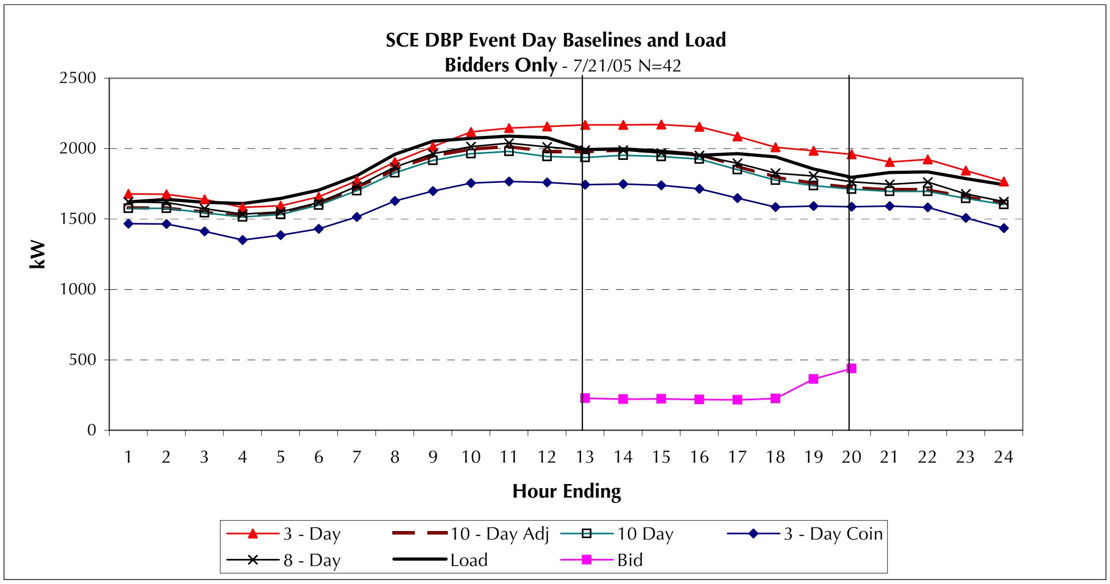
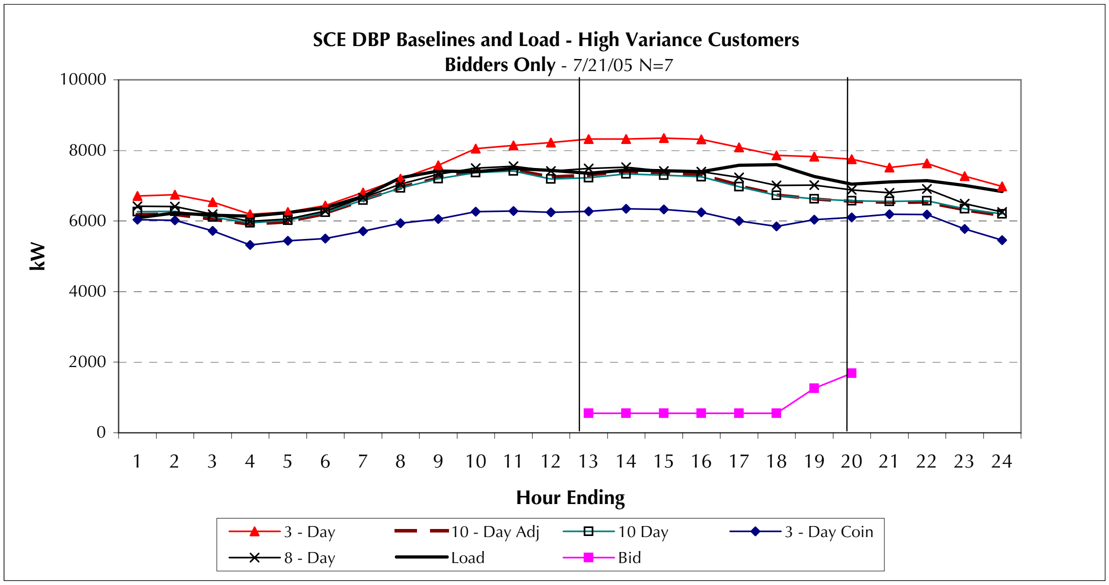
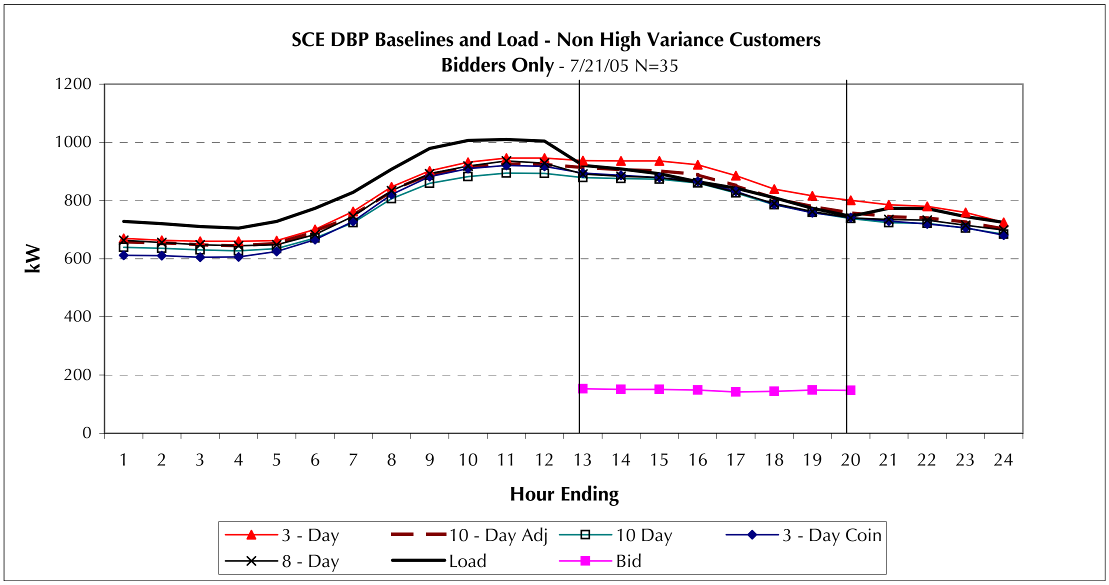


Exhibit D3-2 (Cont.)
SCE DBP Event Day Baselines and Load







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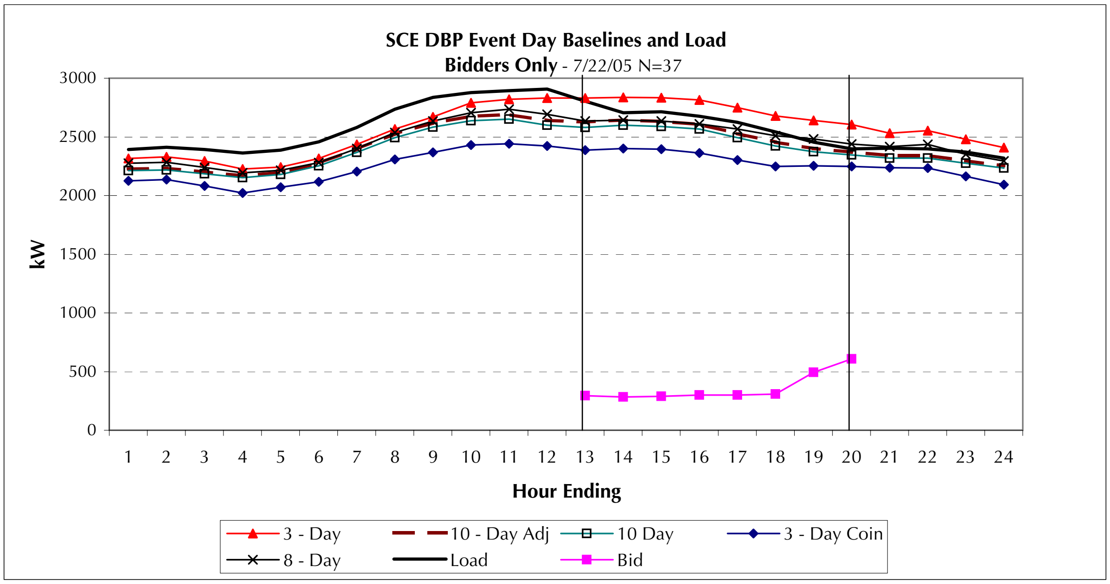
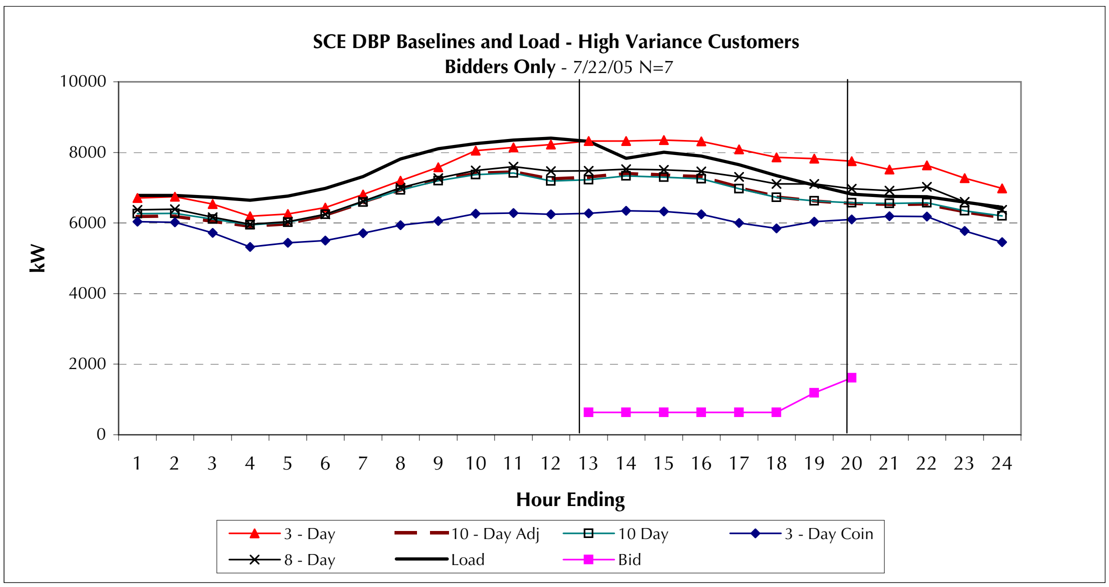
SCE DBP Event Day Baselines and Load





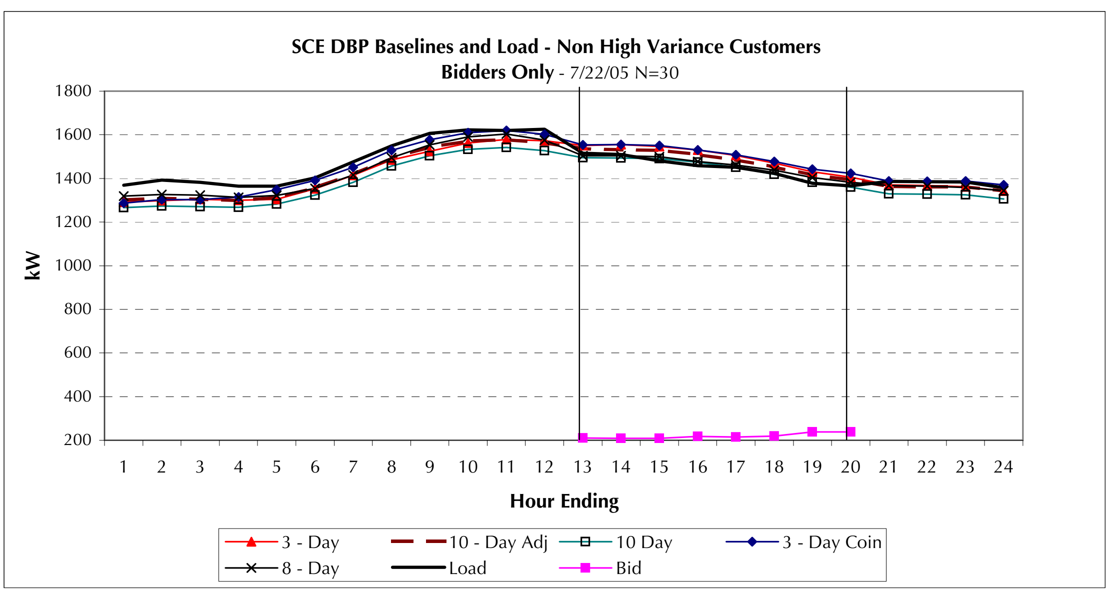
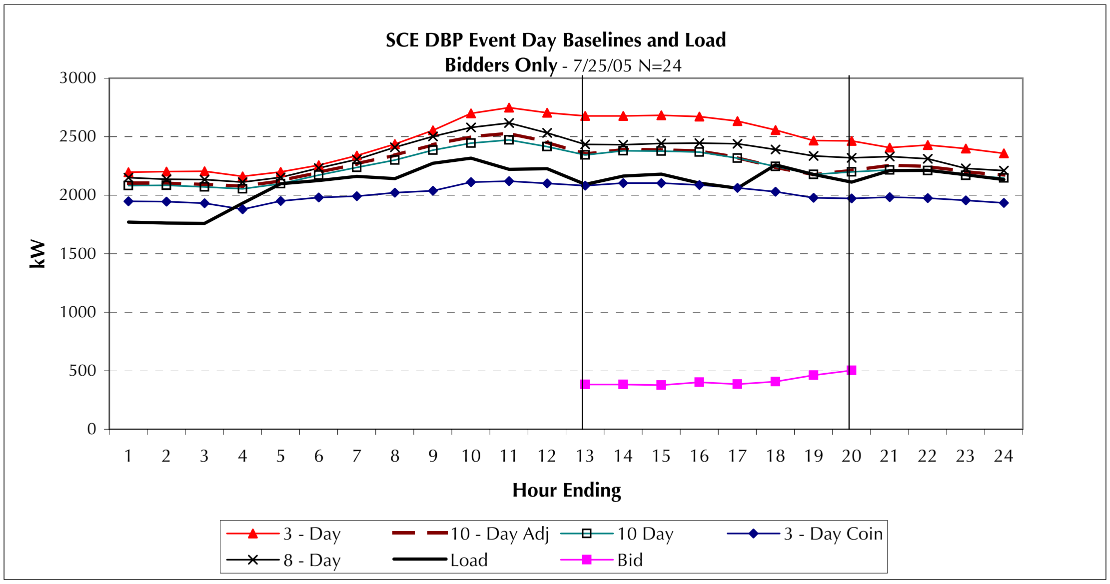
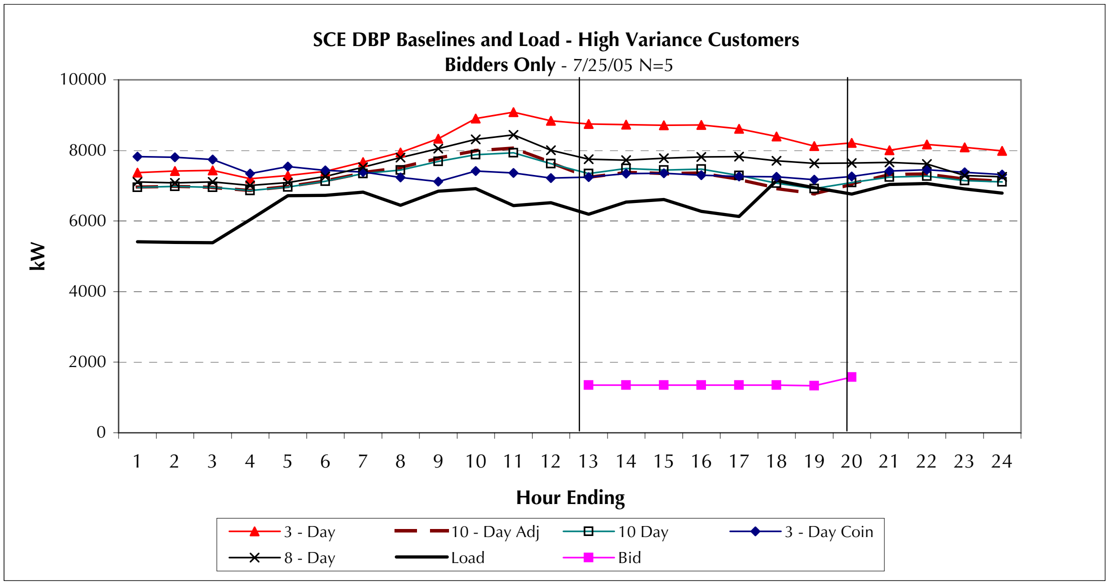


Exhibit D3-2 (Cont.)
SCE DBP Event Day Baselines and Load





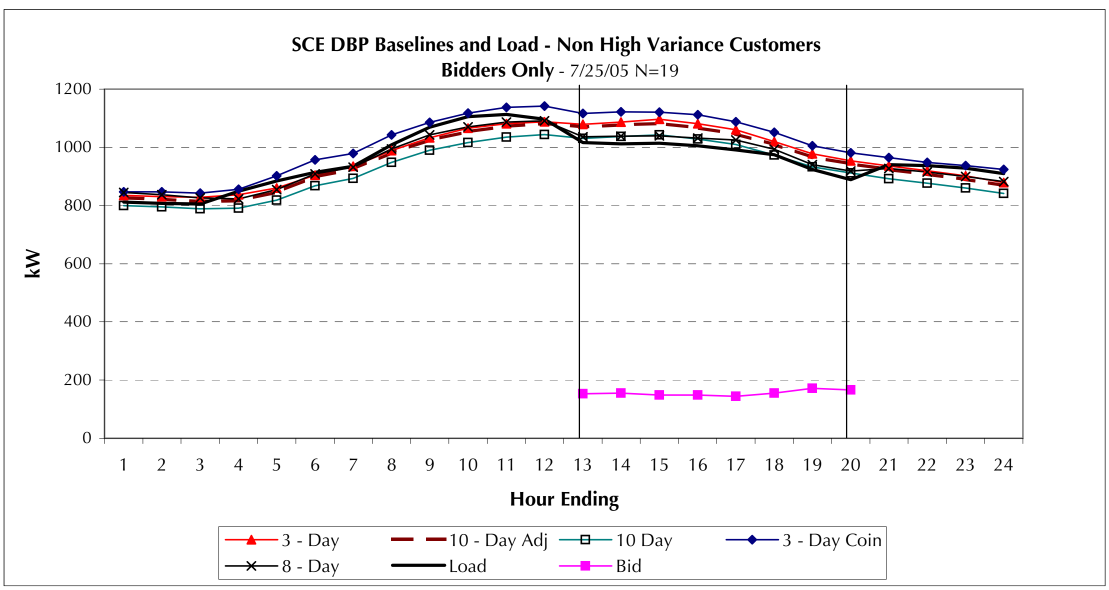
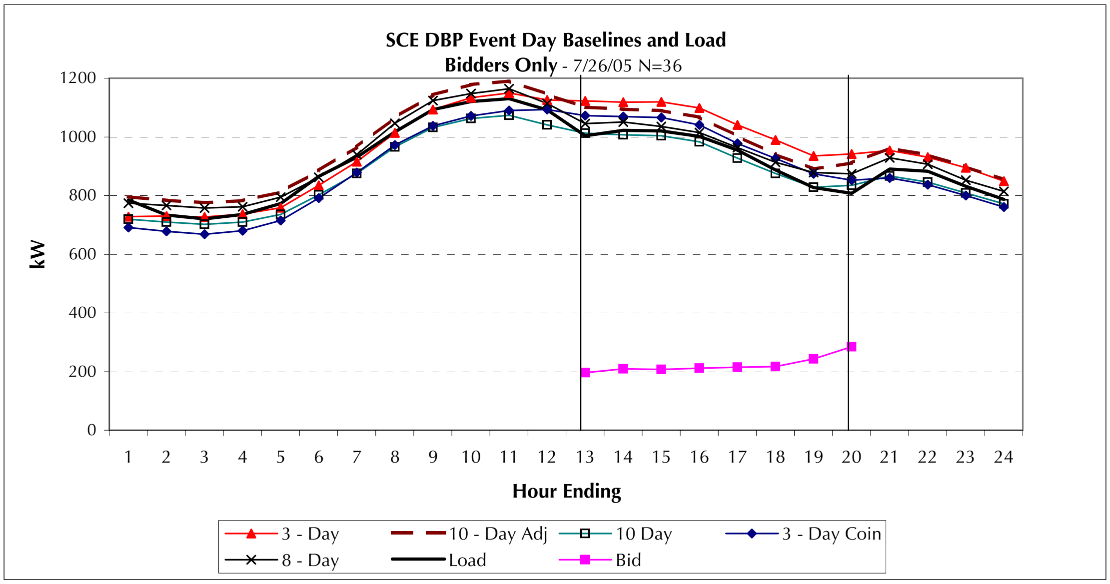
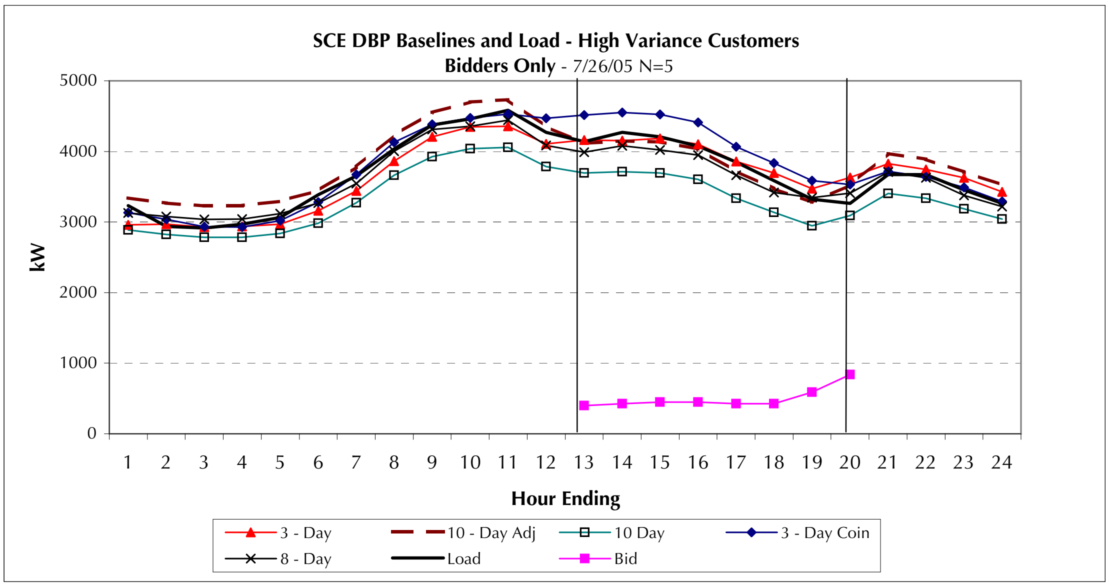


Exhibit D3-2 (Cont.)
SCE DBP Event Day Baselines and Load





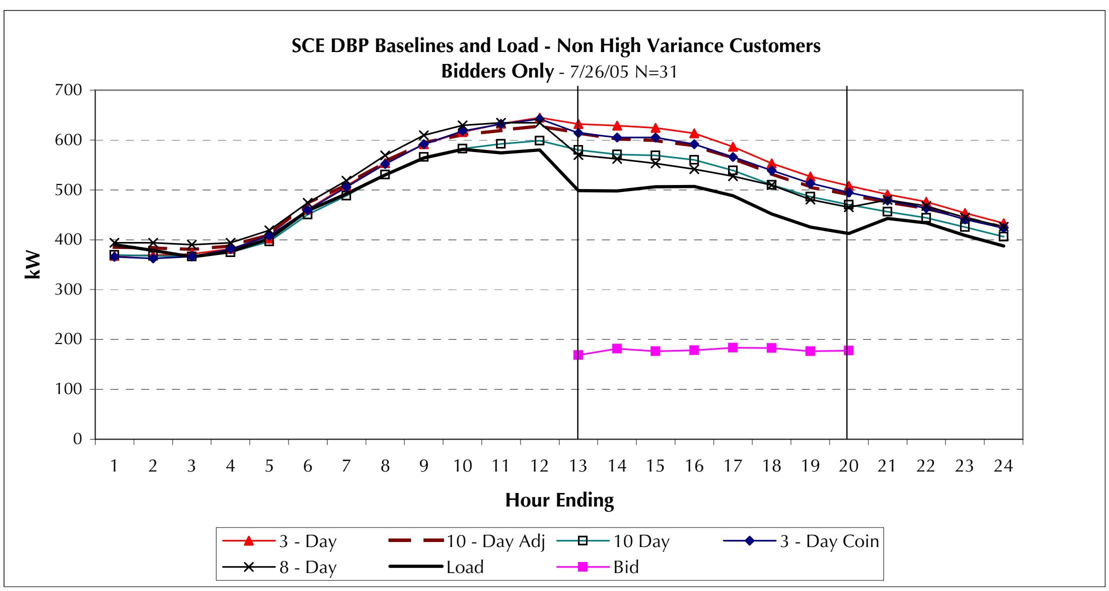
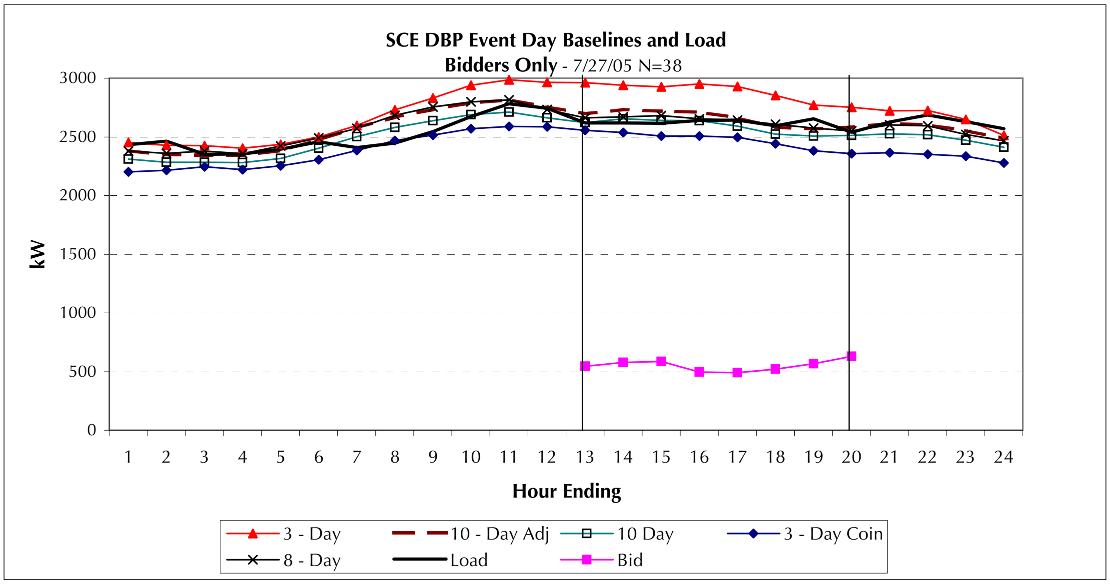
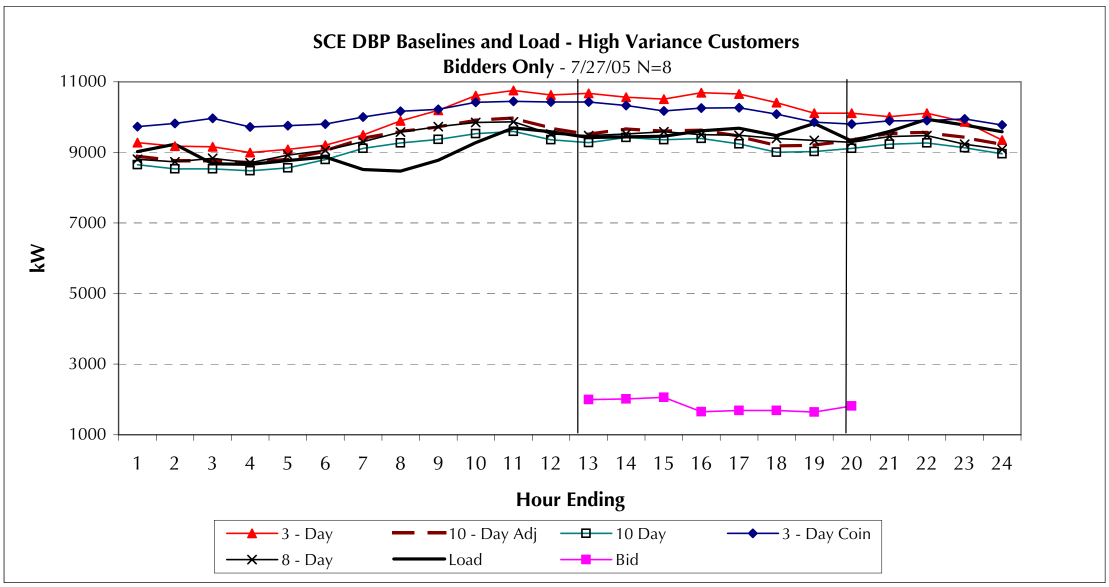


Exhibit D3-2 (Cont.)
SCE DBP Event Day Baselines and Load





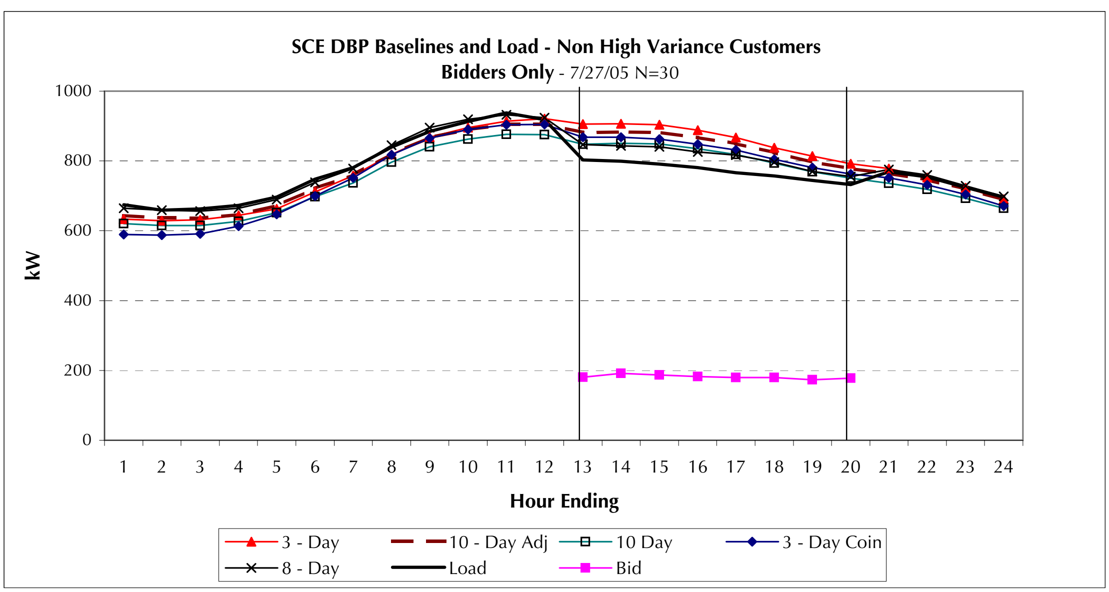
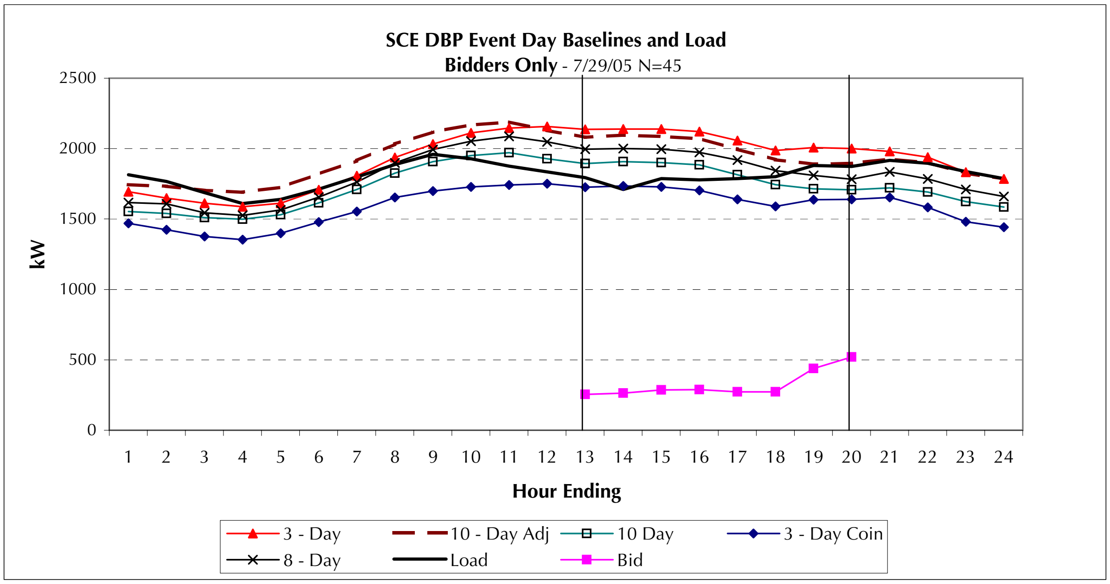
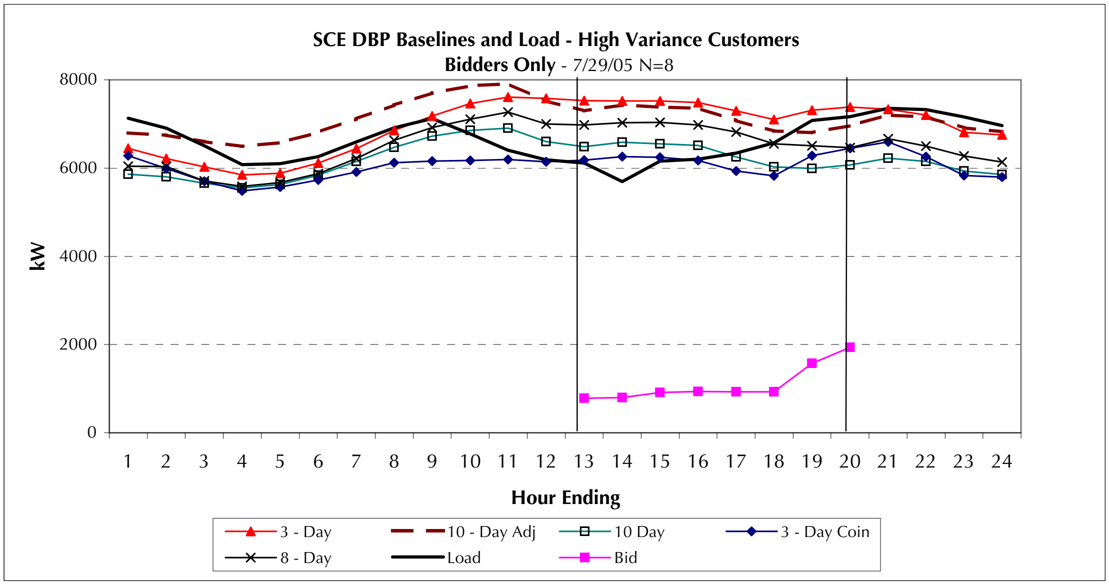


Exhibit D3-2 (Cont.)
SCE DBP Event Day Baselines and Load





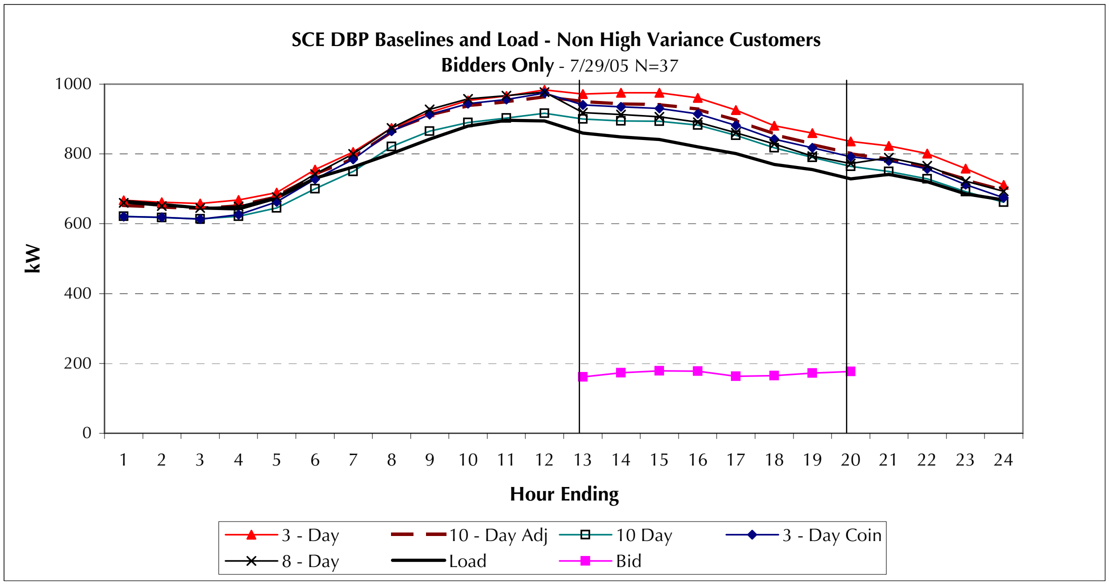
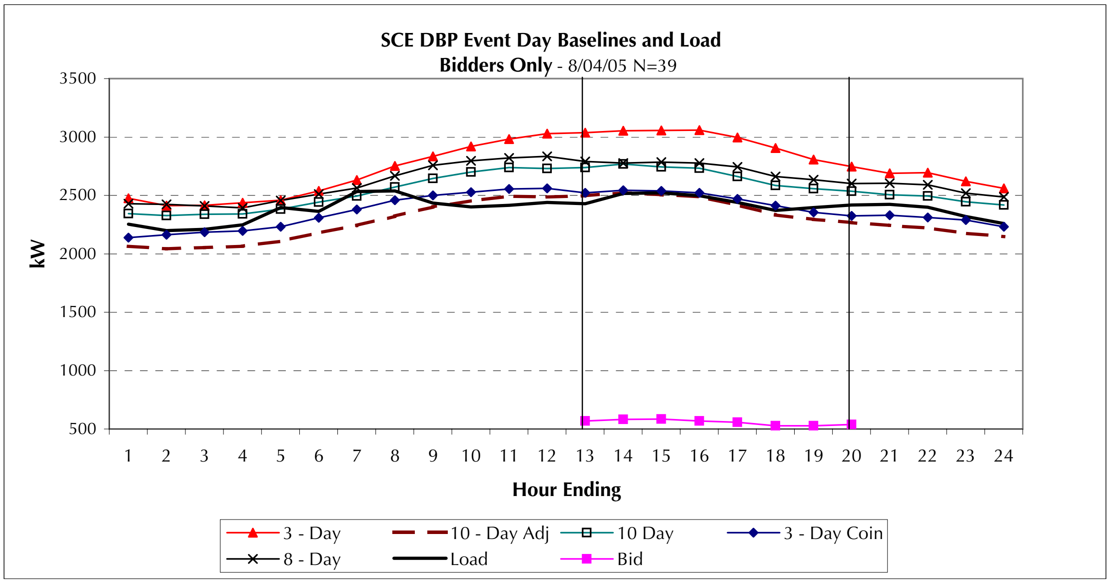
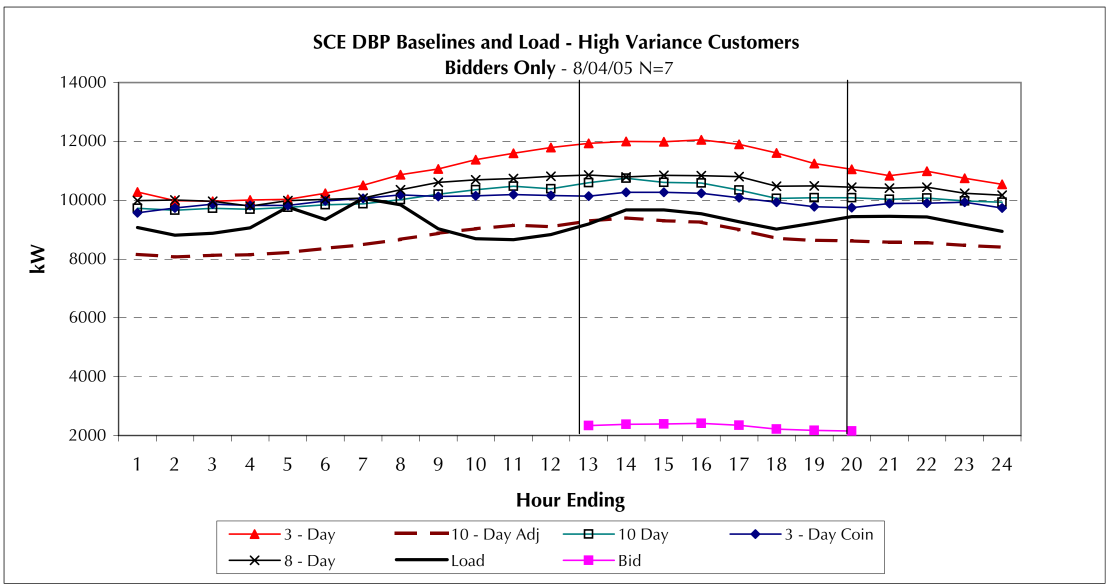


Exhibit D3-2 (Cont.)
SCE DBP Event Day Baselines and Load





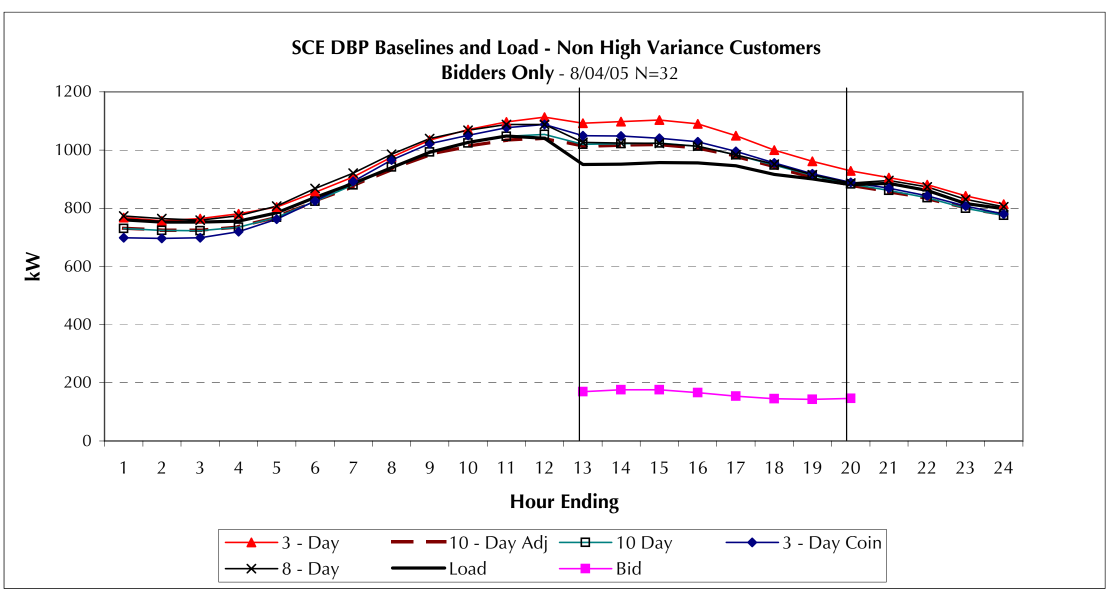
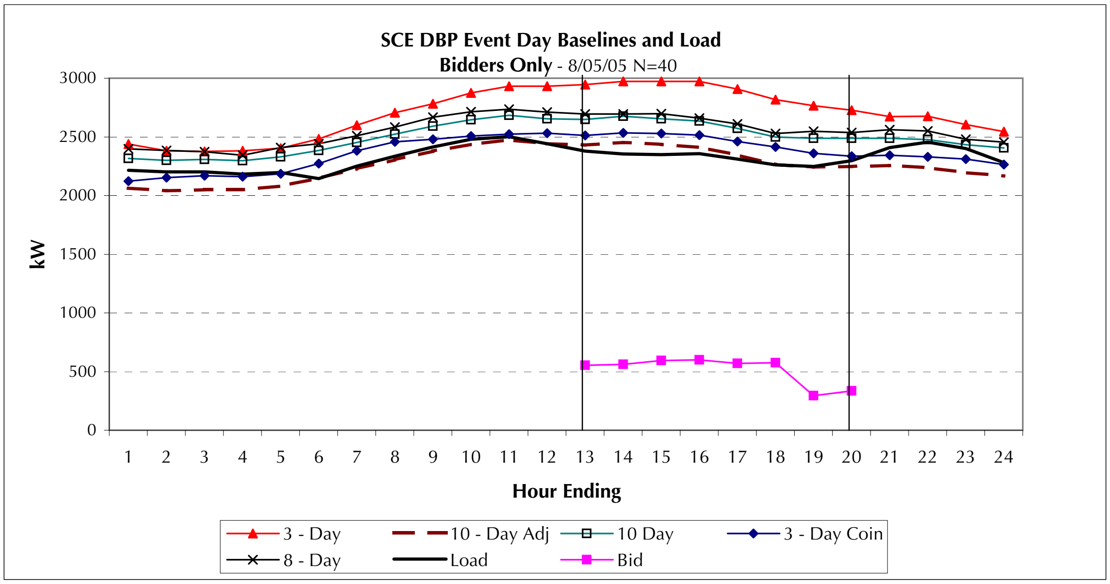
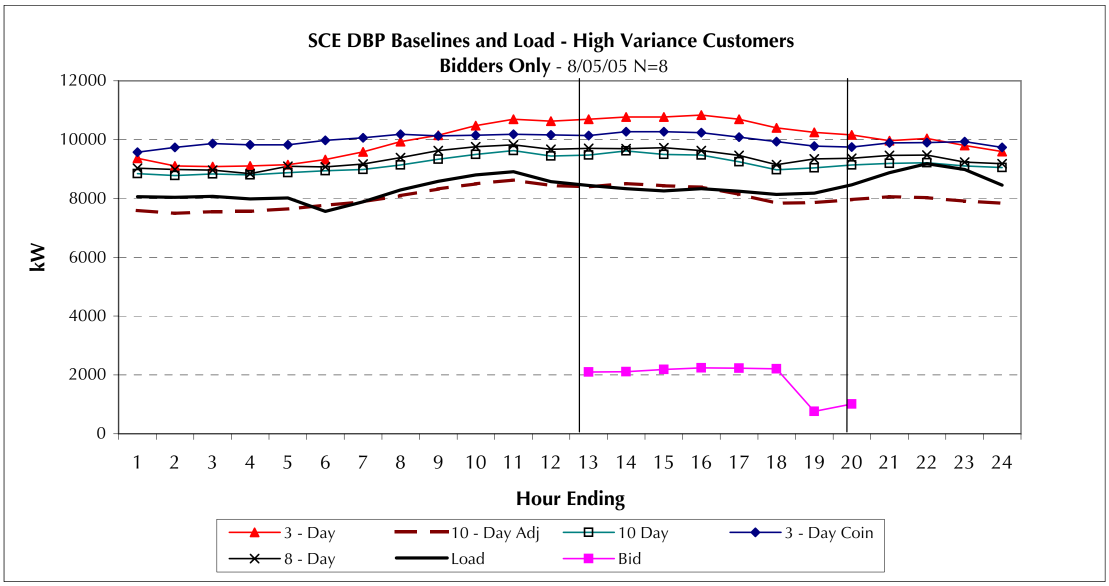


Exhibit D3-2 (Cont.)
SCE DBP Event Day Baselines and Load





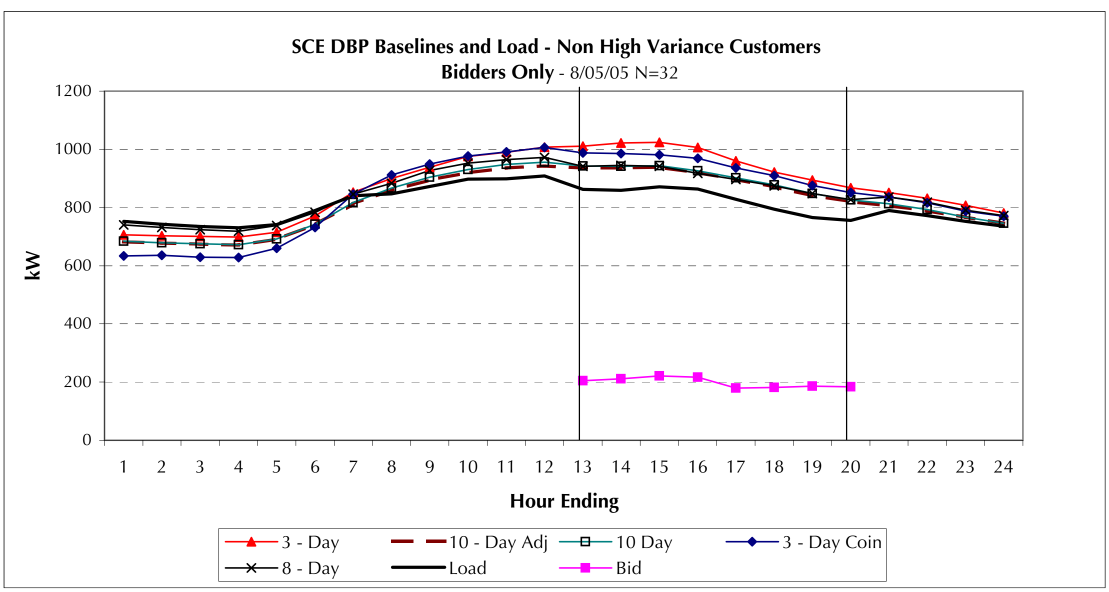


Exhibit D3-3
SDG&E DBP Event Day Baselines and Load

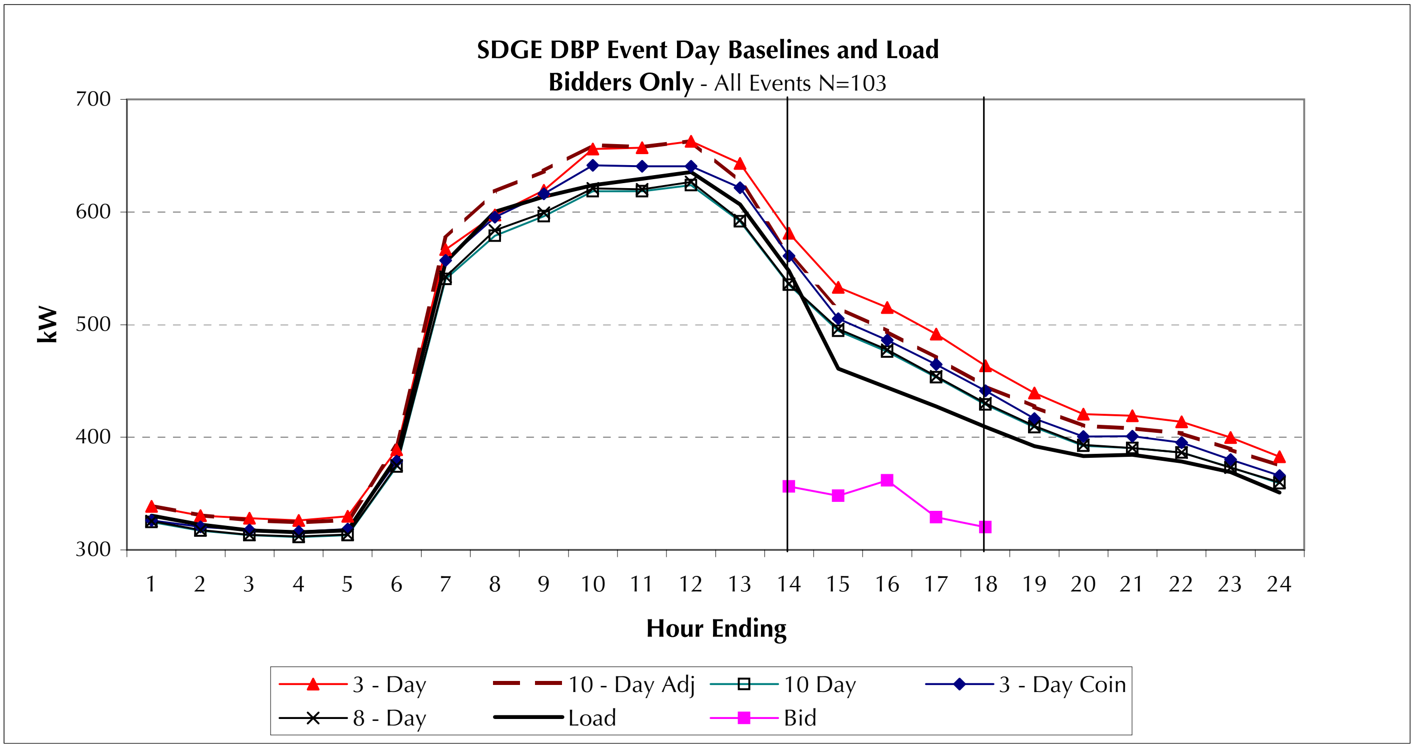
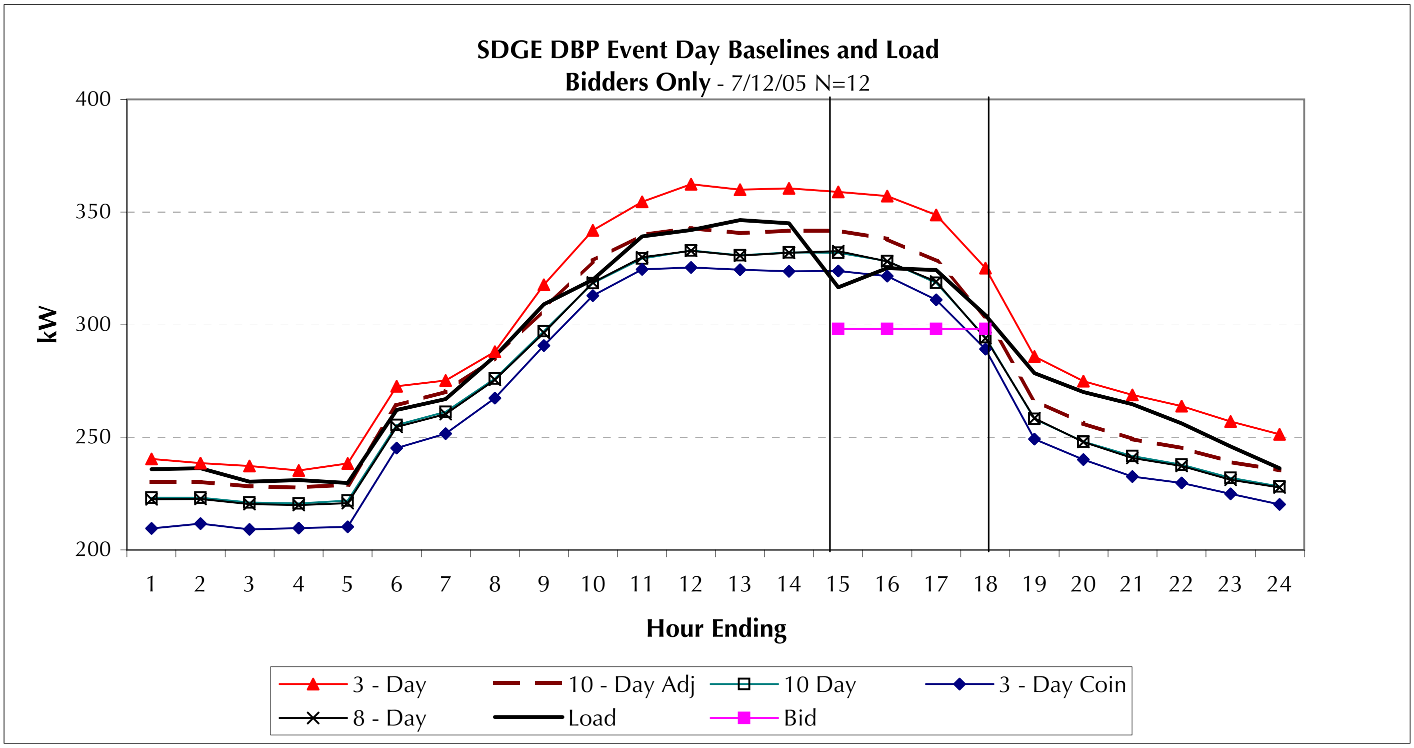


Exhibit D3-3 (Cont.)
SDG&E DBP Event Day Baselines and Load



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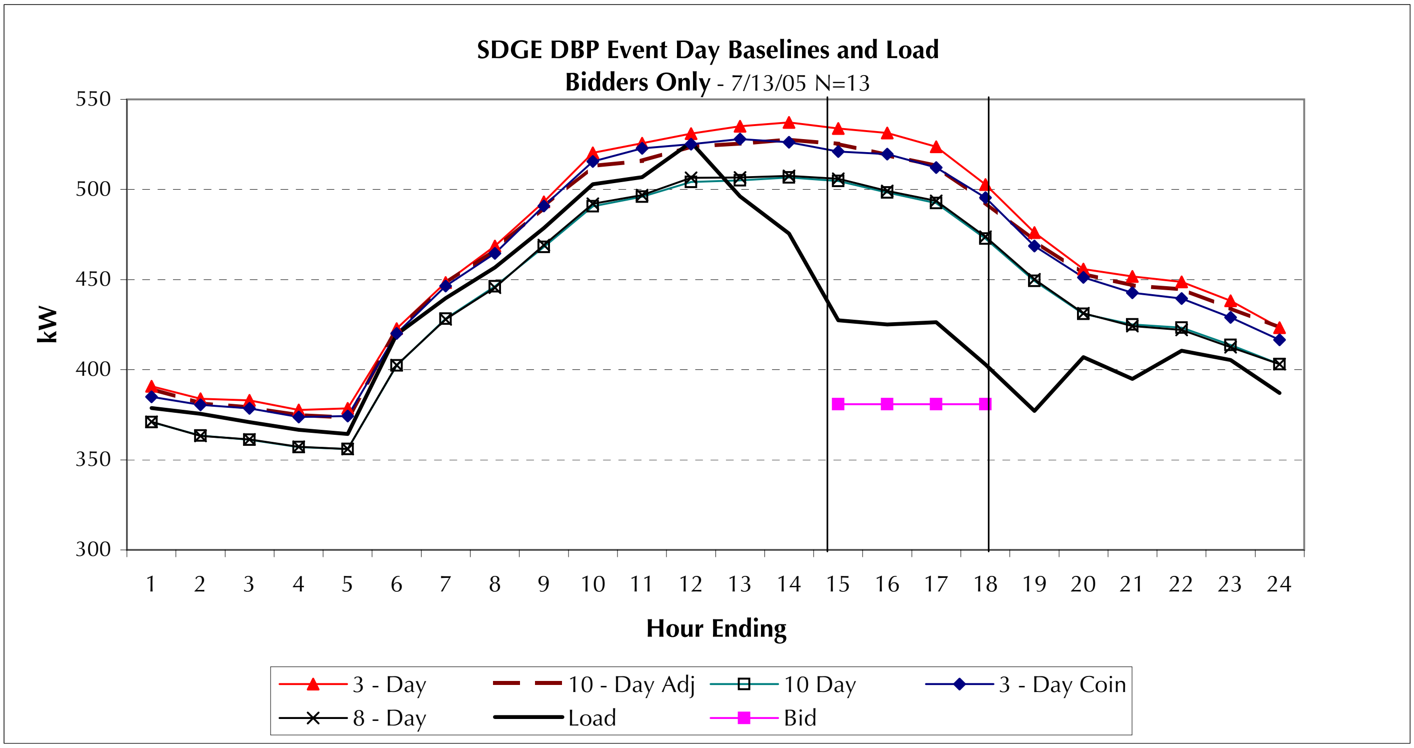
SDG&E DBP Event Day Baselines and Load



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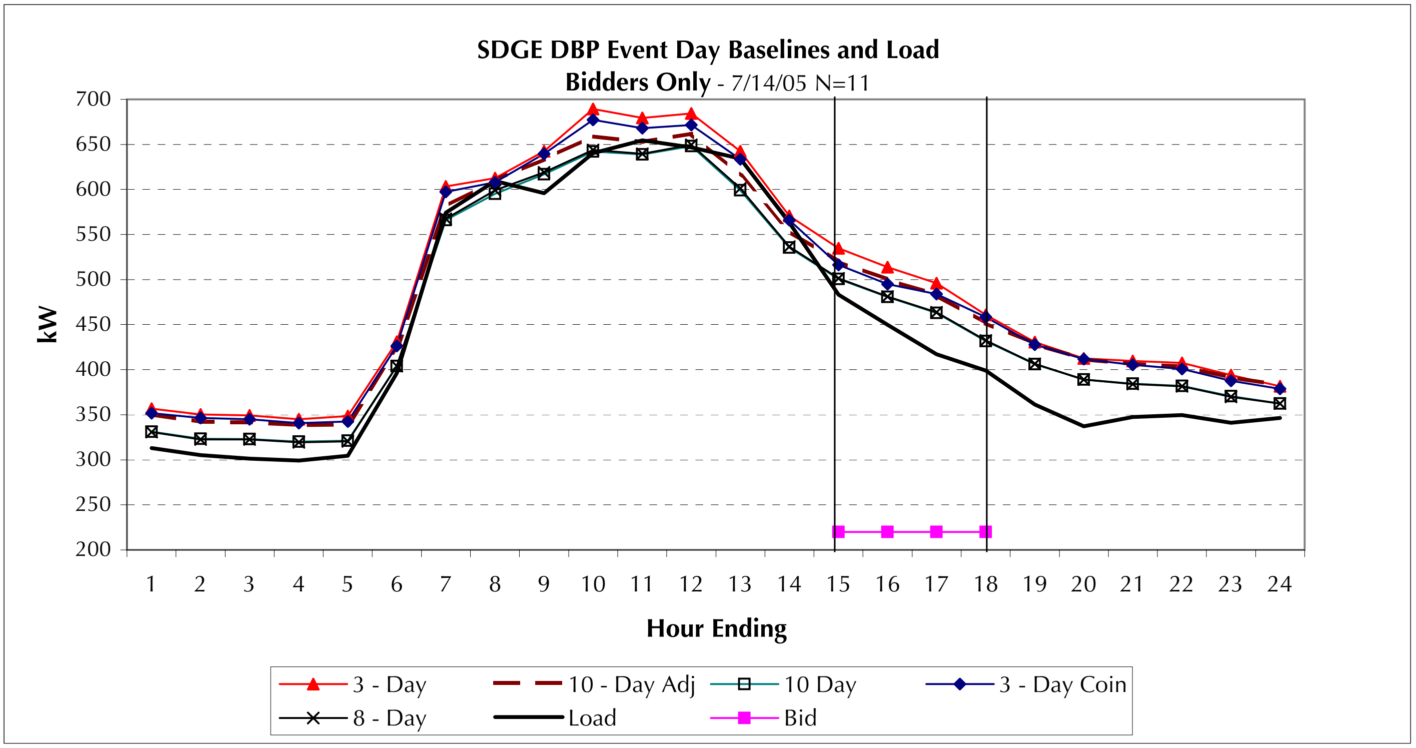
SDG&E DBP Event Day Baselines and Load



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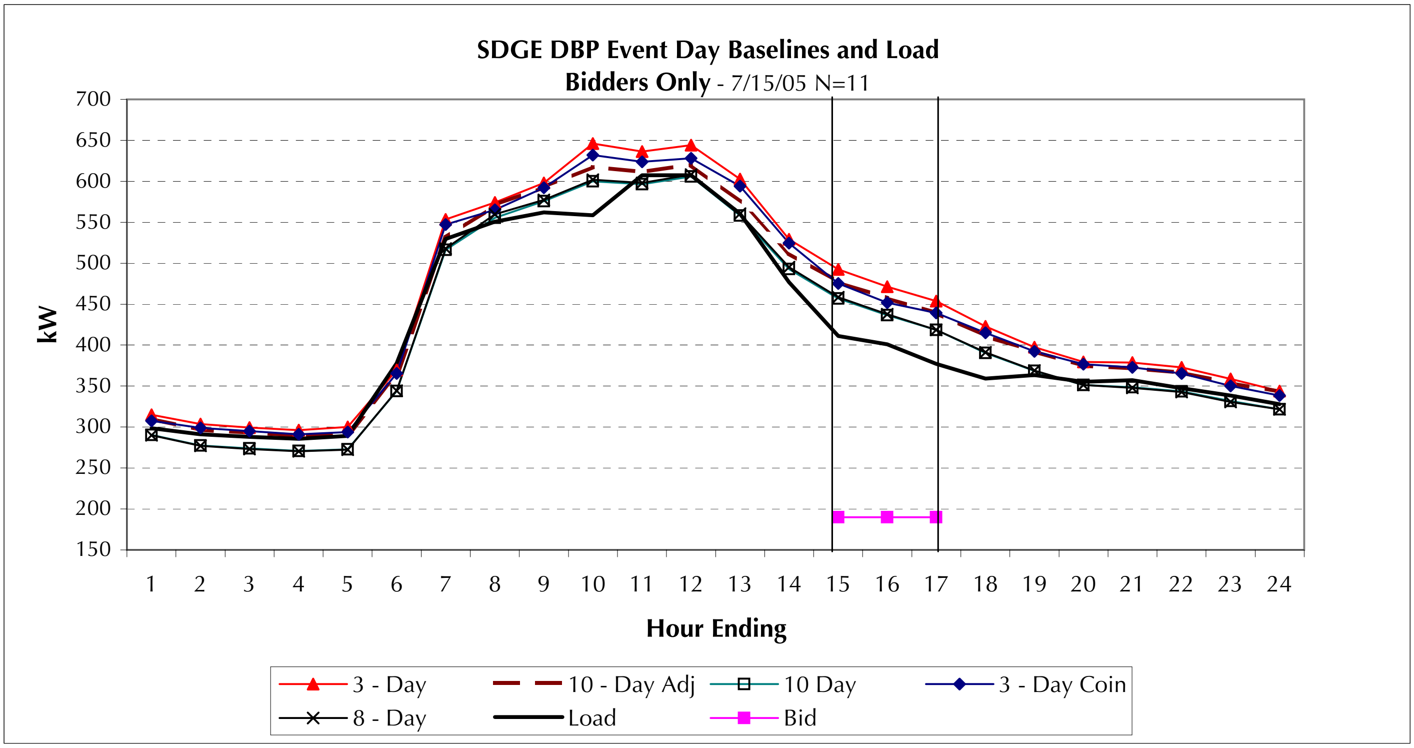
SDG&E DBP Event Day Baselines and Load



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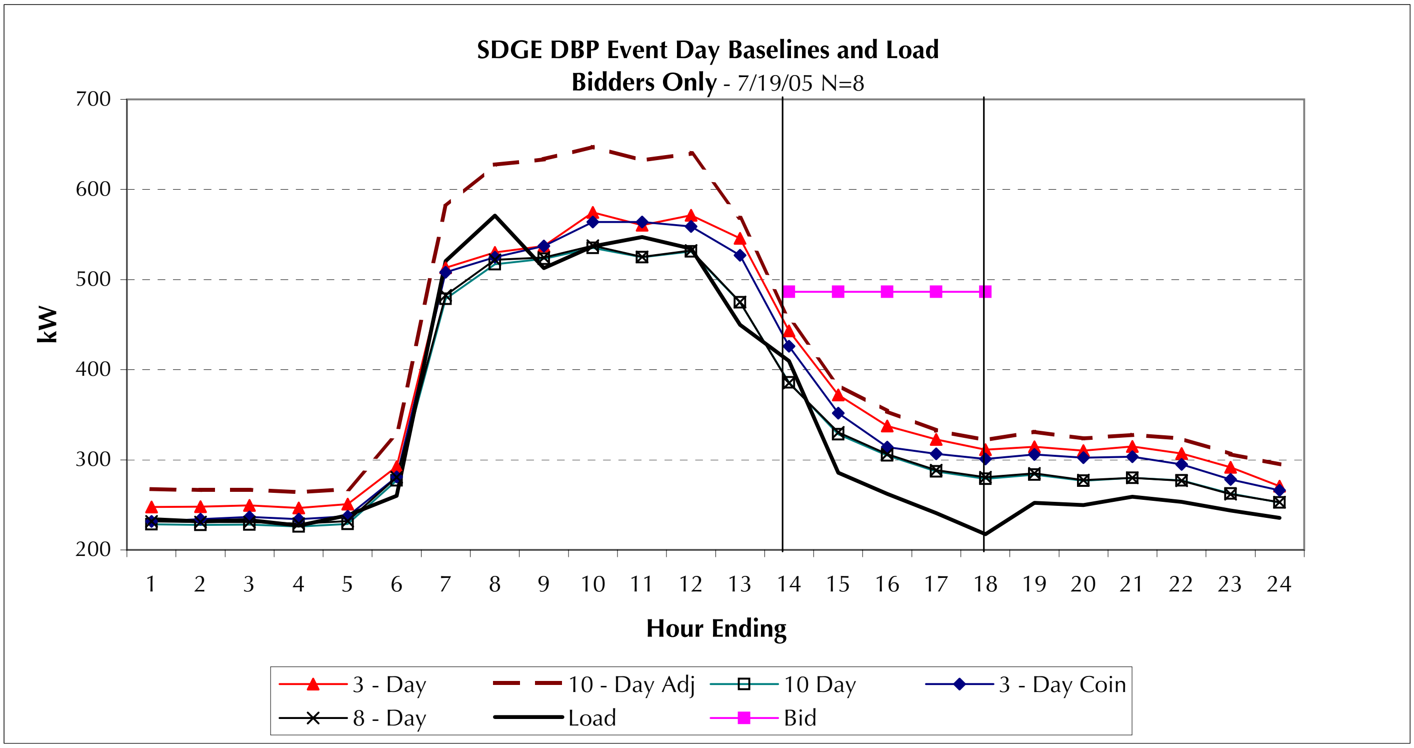

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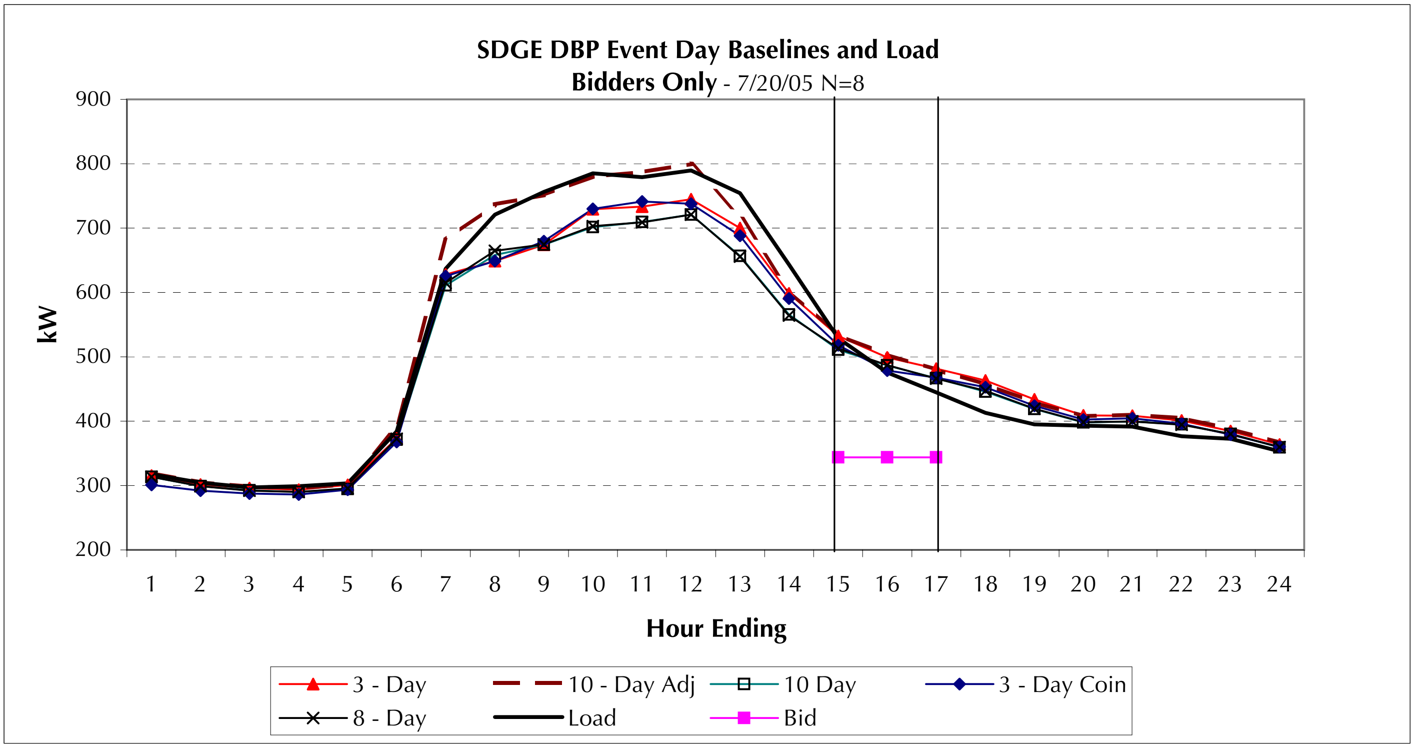

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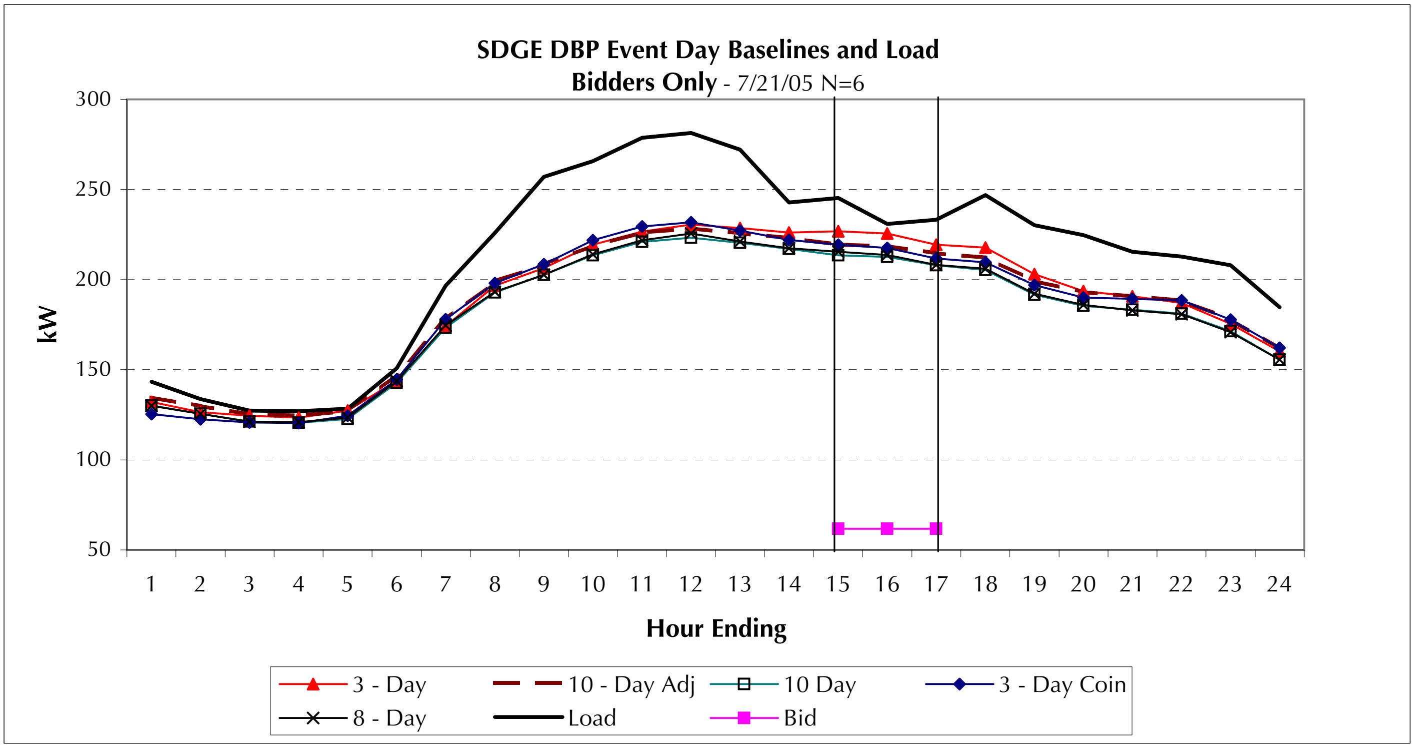

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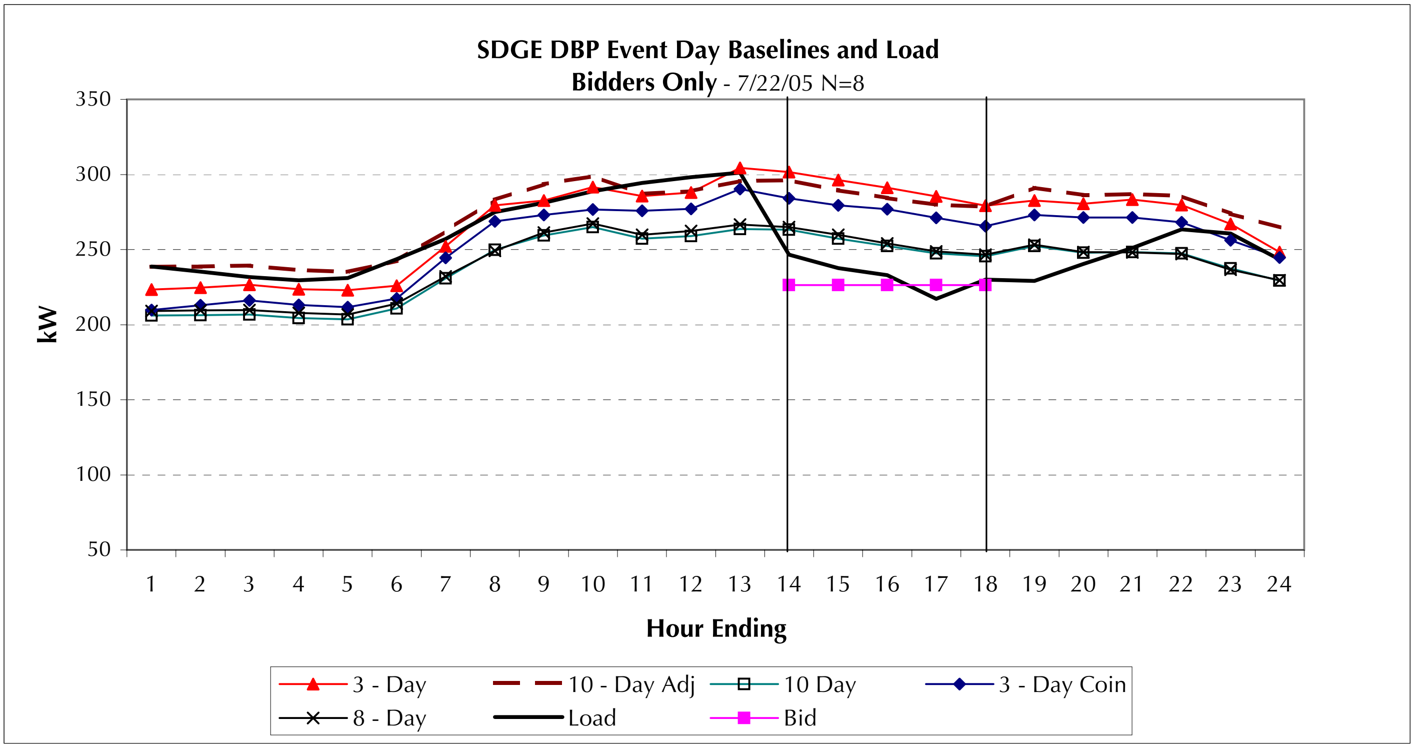

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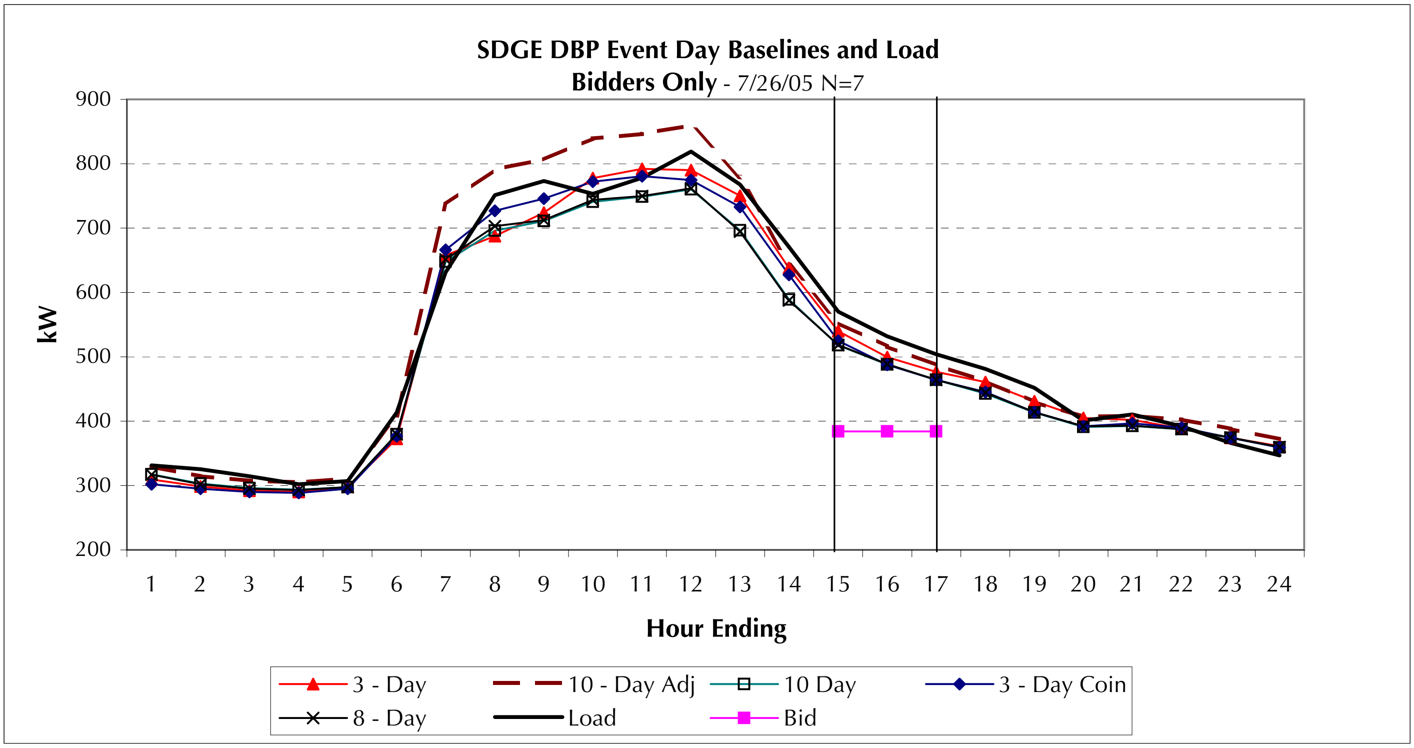

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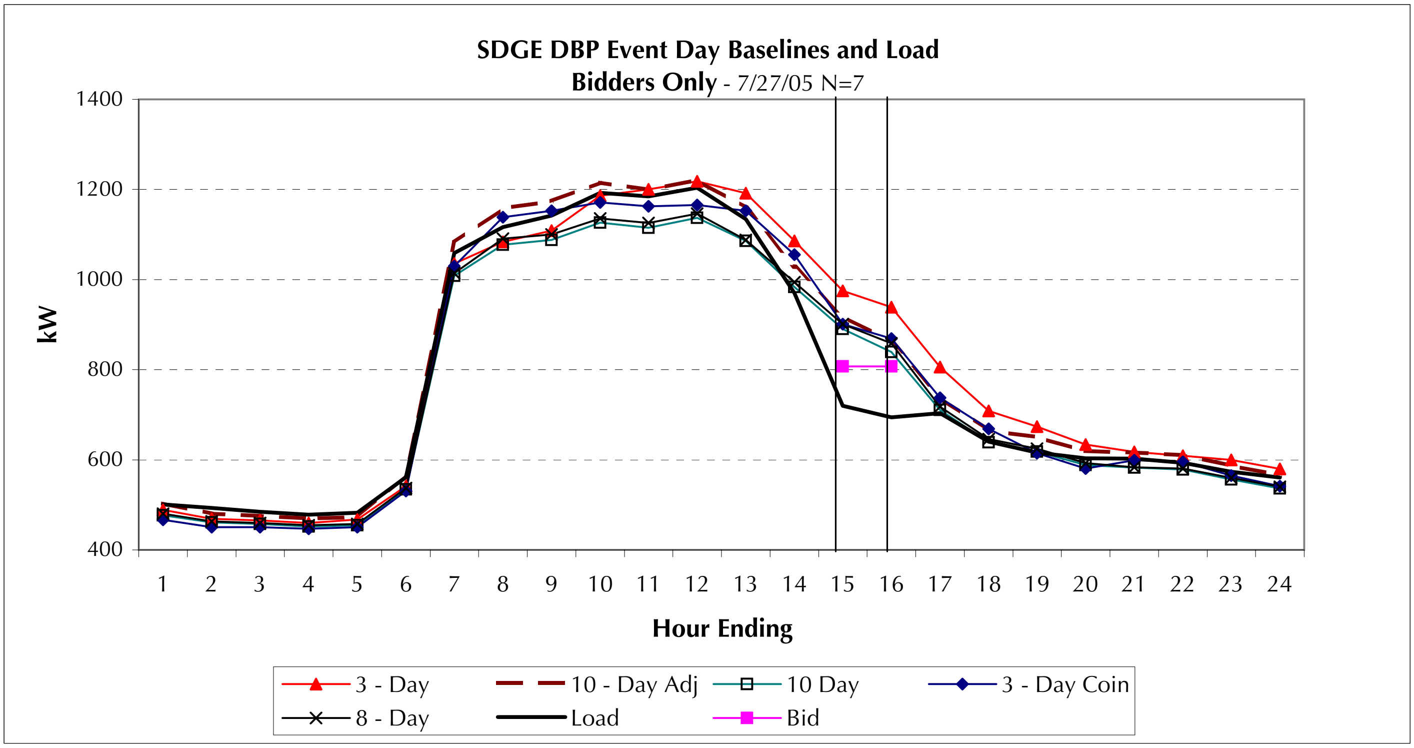

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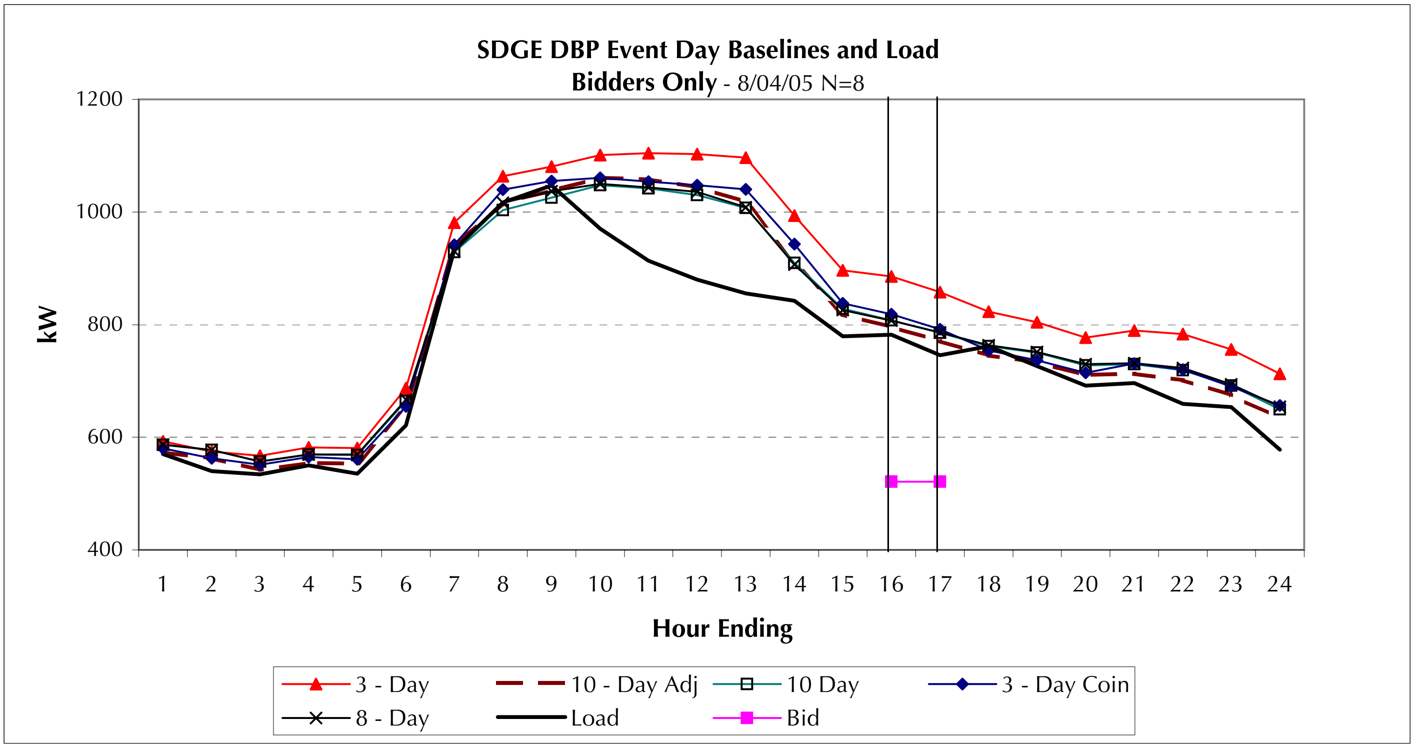

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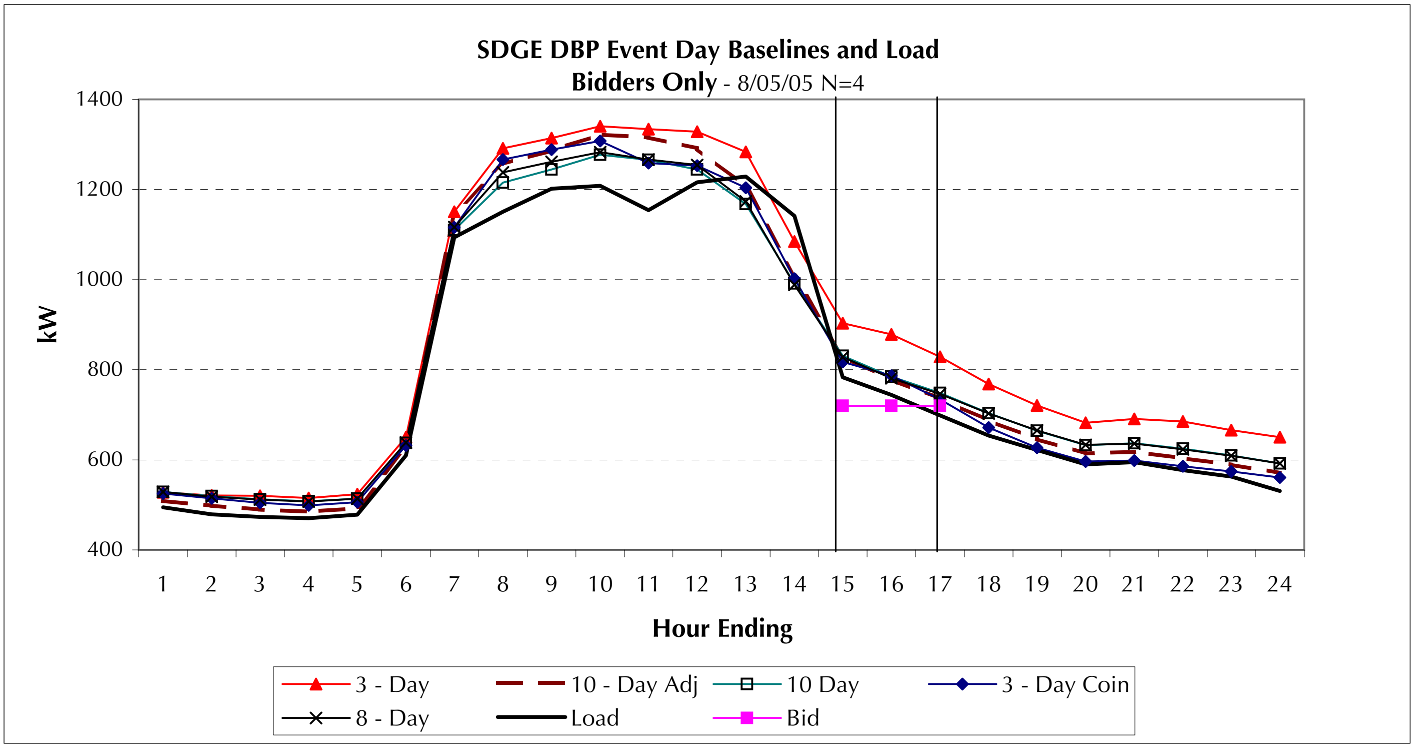
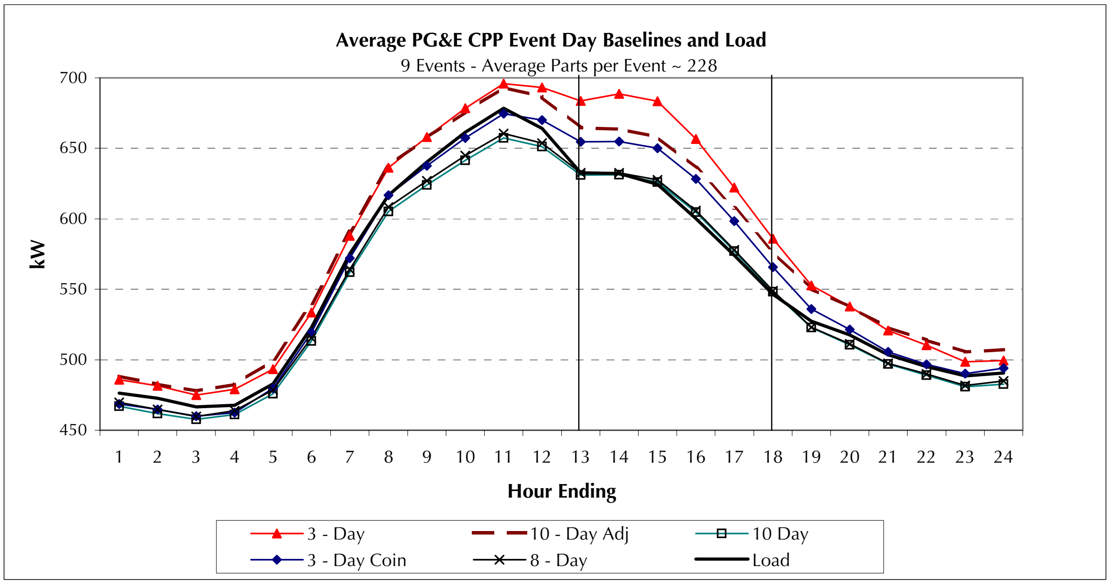
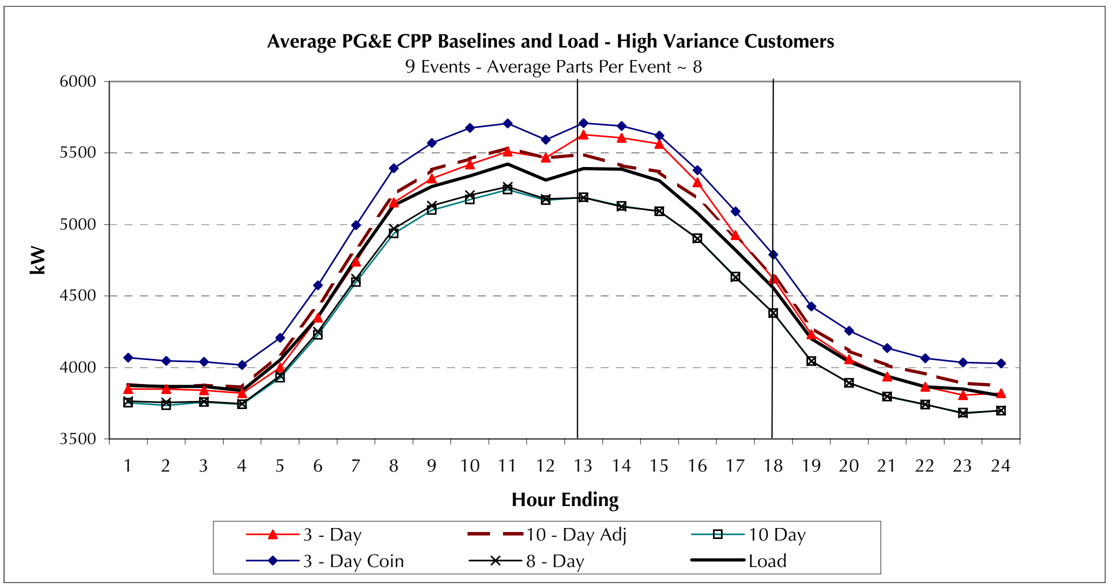
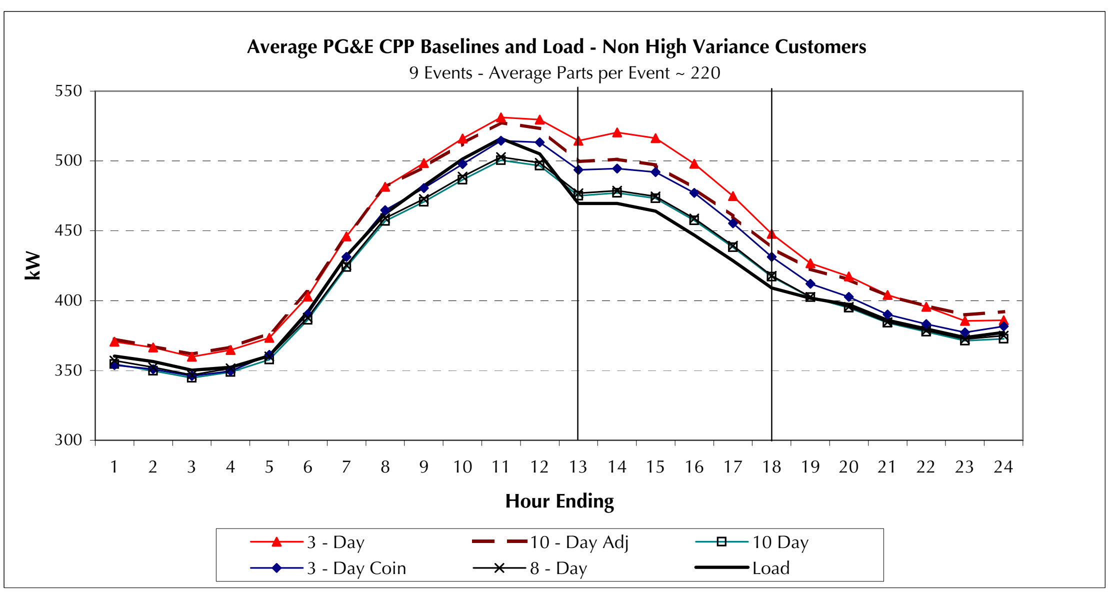


Exhibit D3-4
PGE CPP Event Day Baselines and Load







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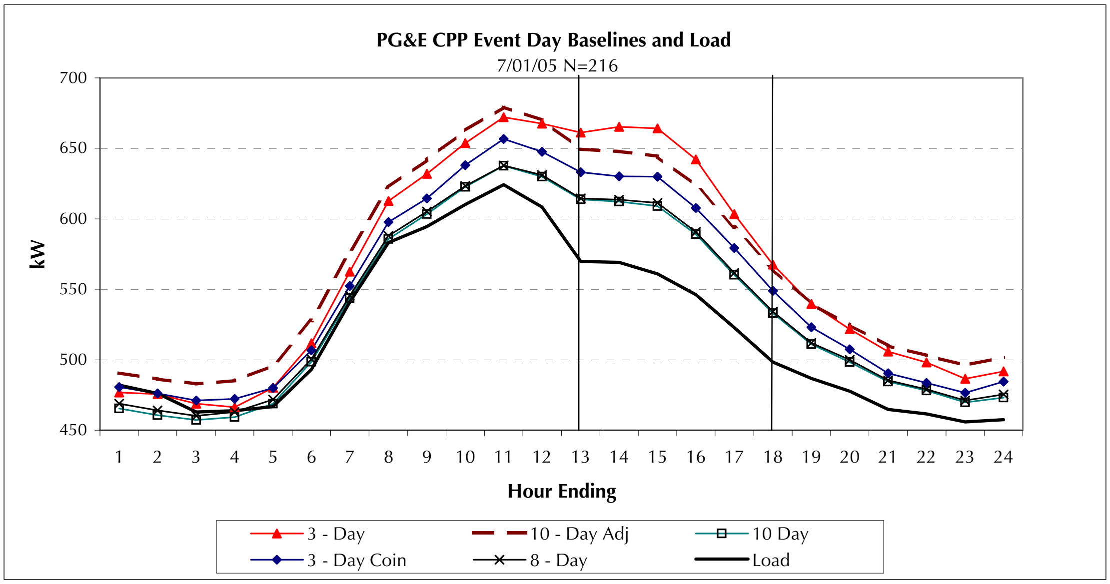

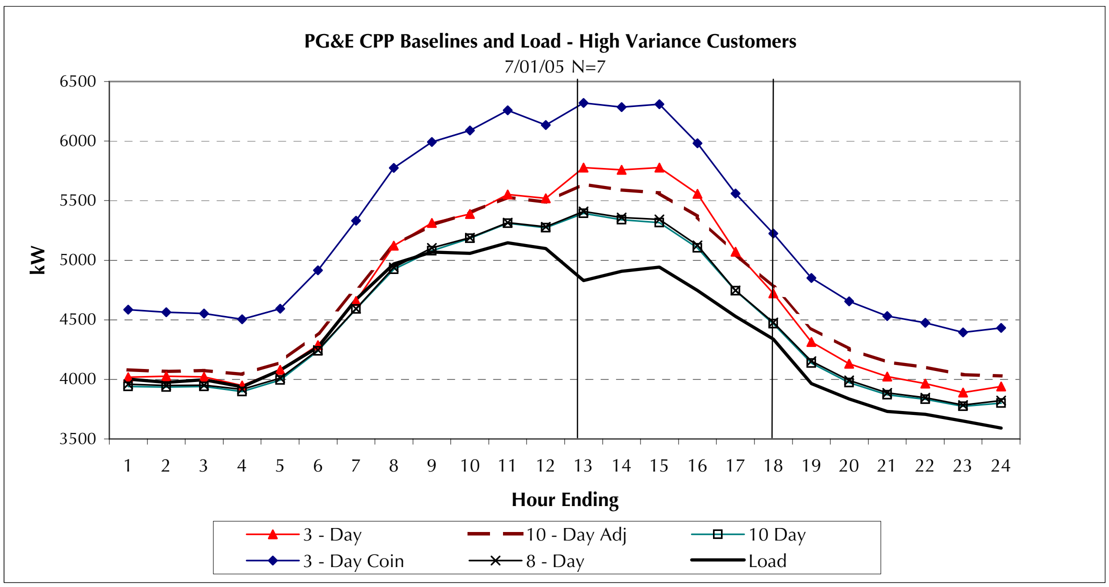

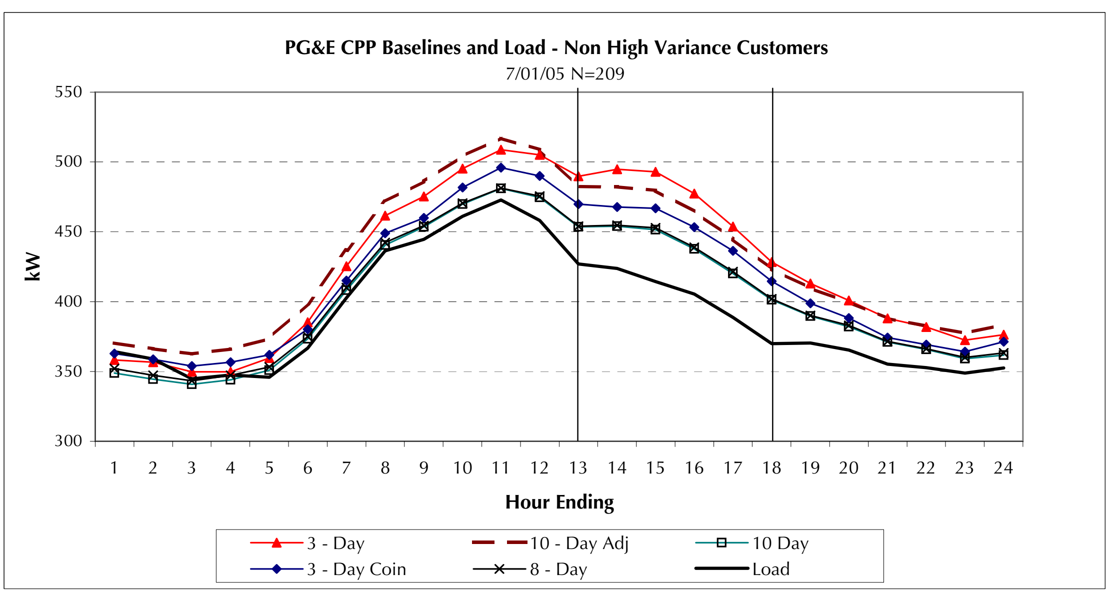

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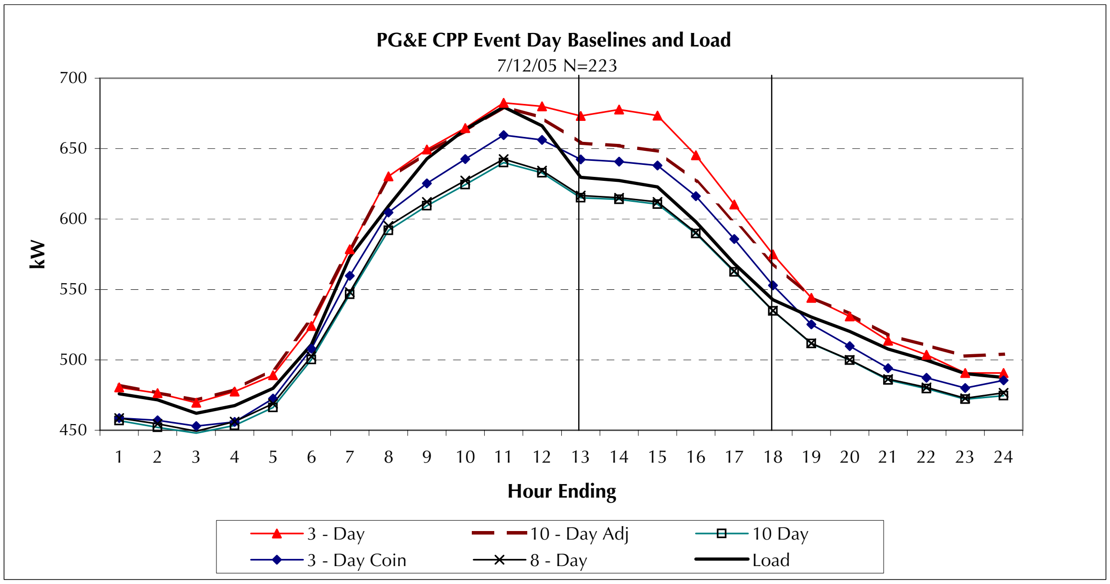
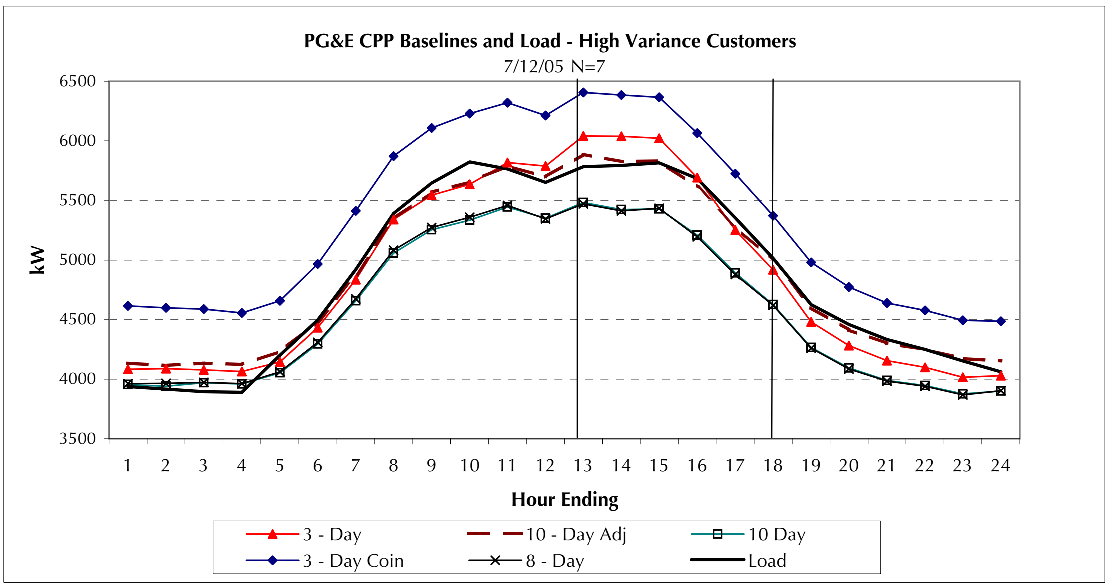
PGE CPP Event Day Baselines and Load





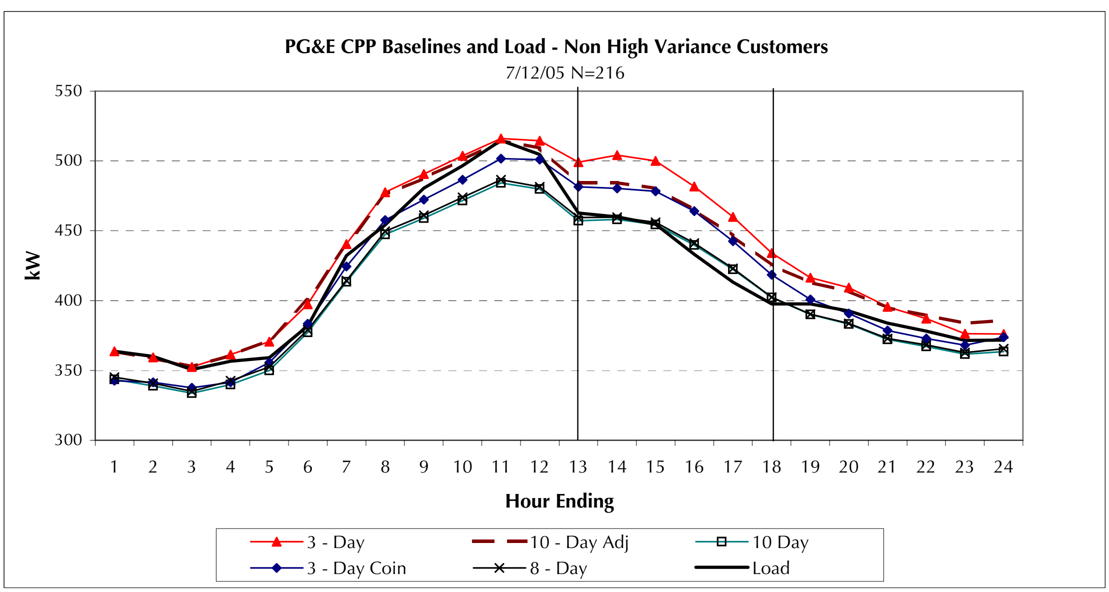
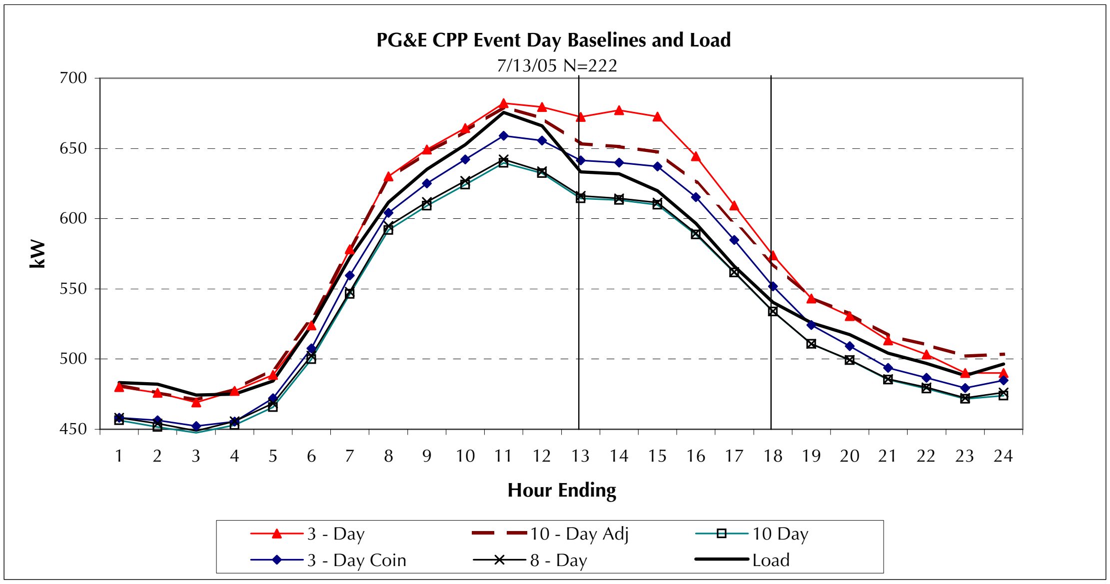
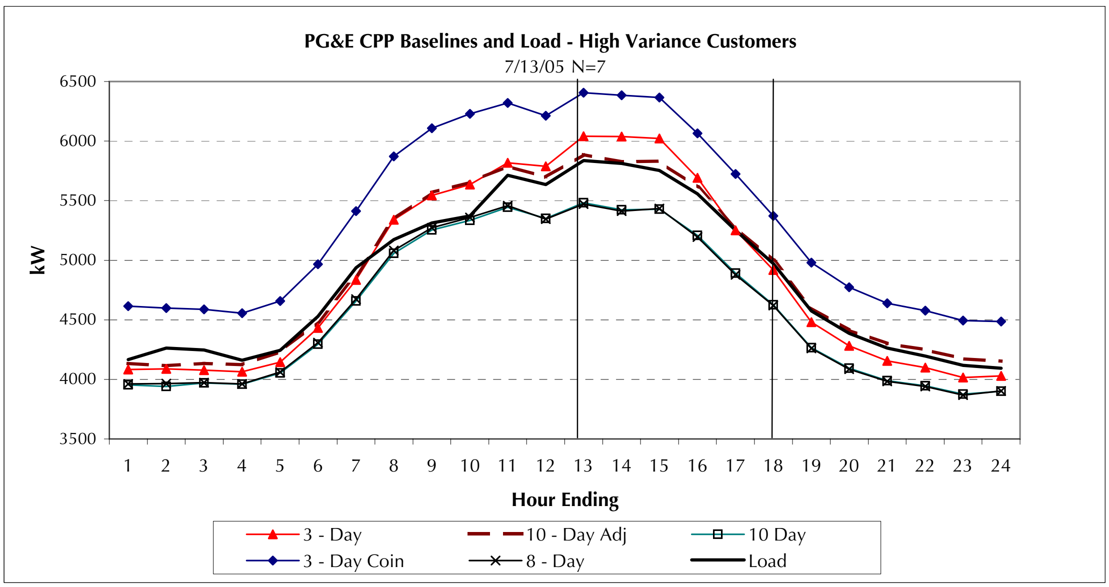
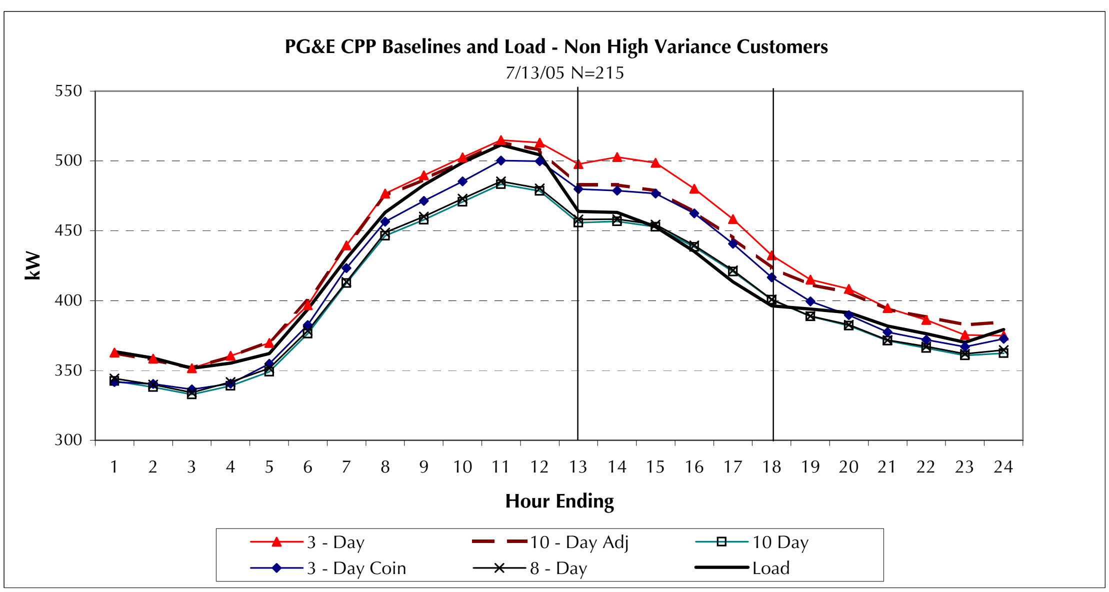


Exhibit D3-4 (Cont.)
PGE CPP Event Day Baselines and Load







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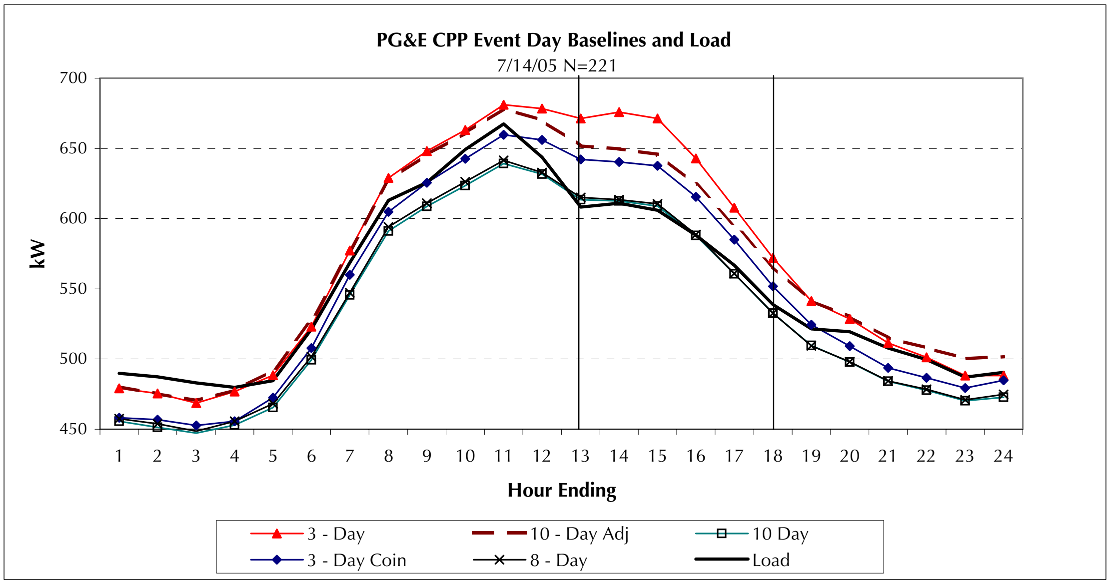
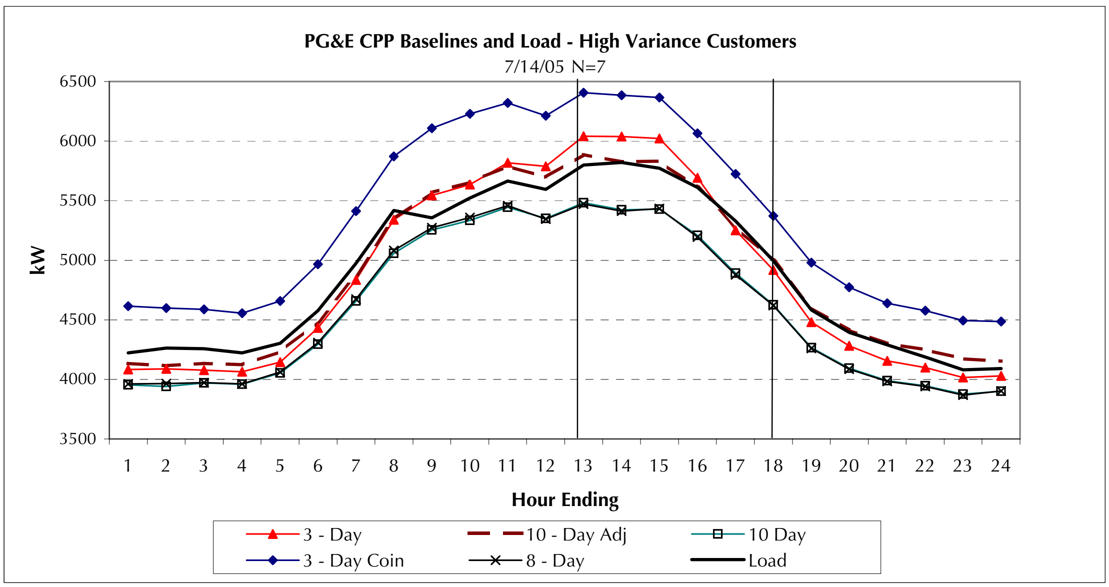
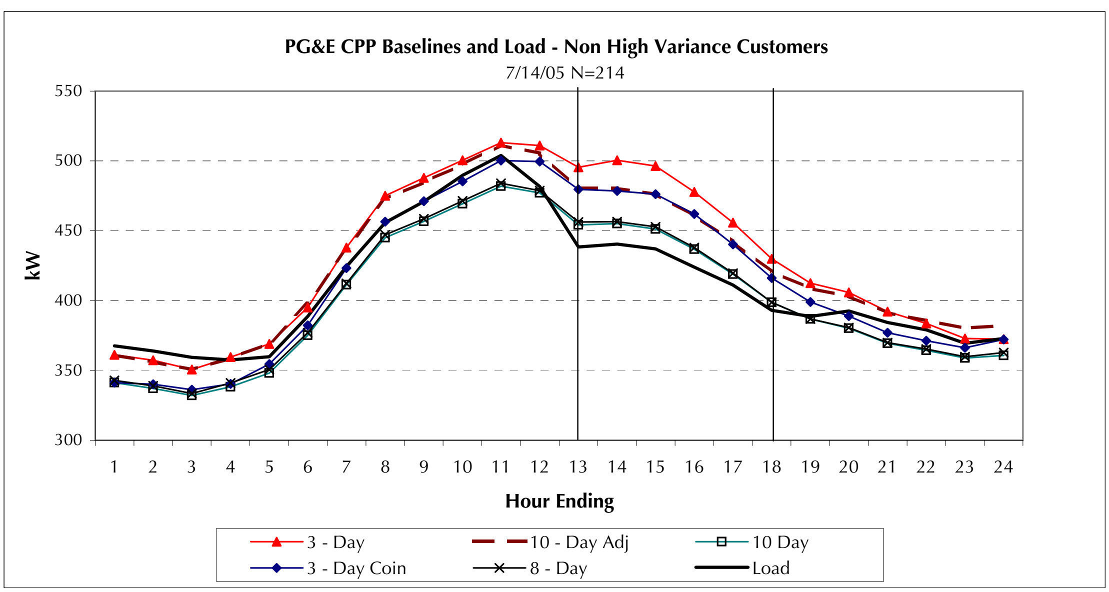
PGE CPP Event Day Baselines and Load







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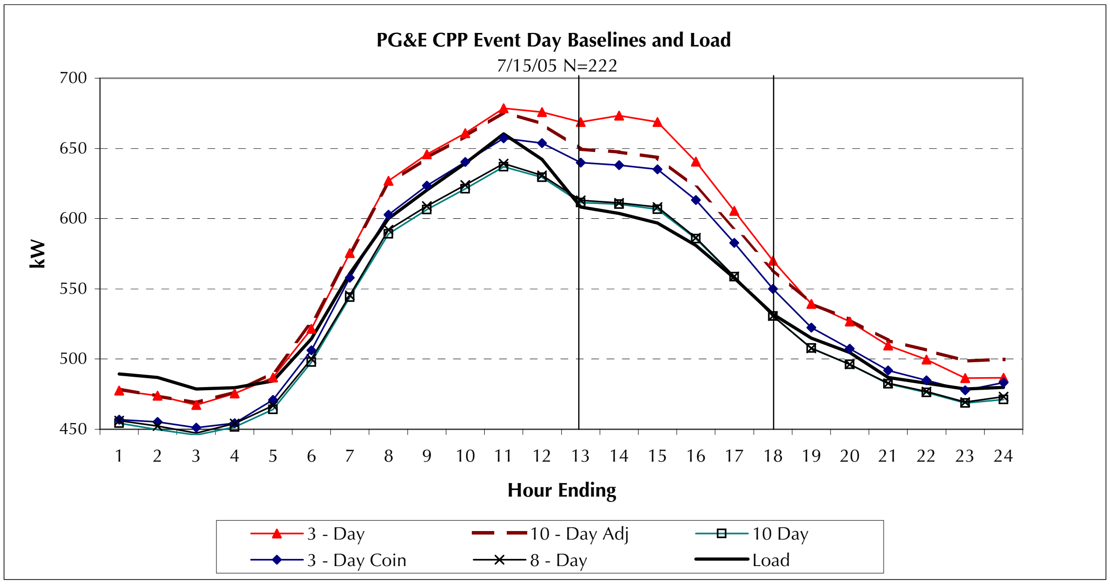
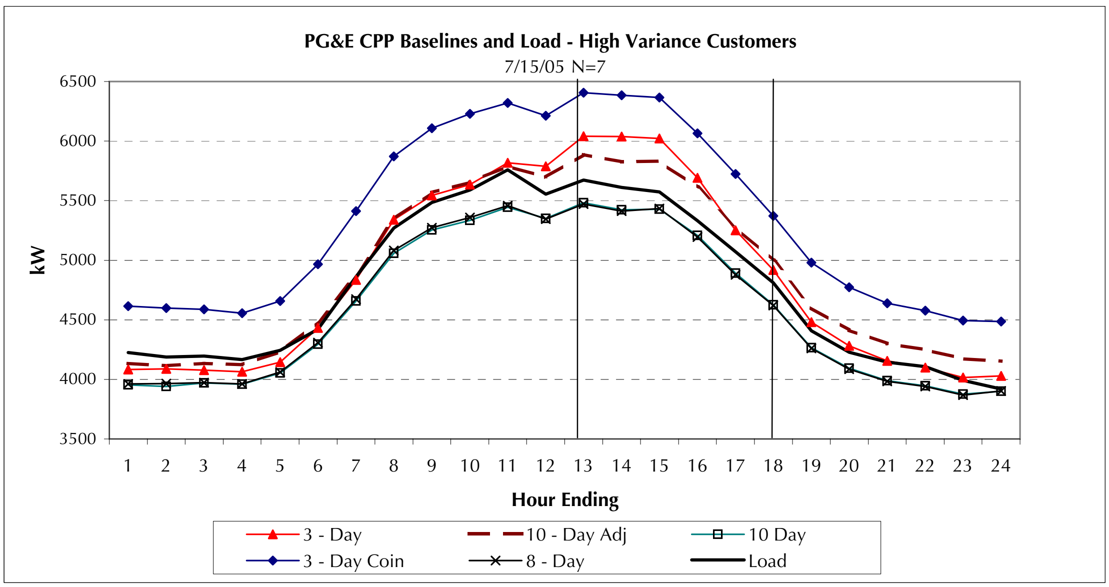
PGE CPP Event Day Baselines and Load





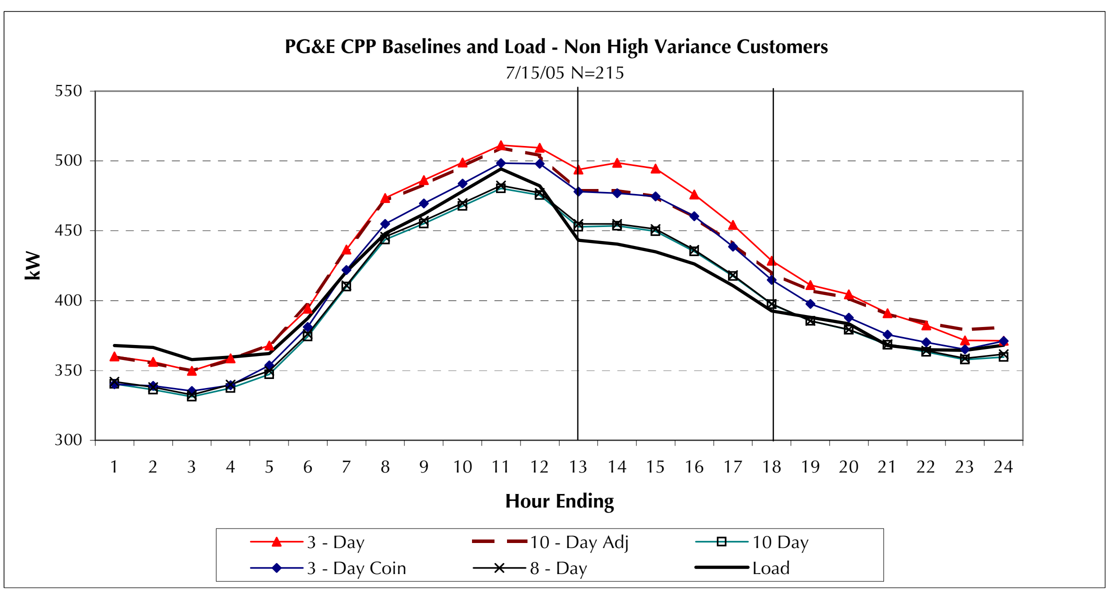
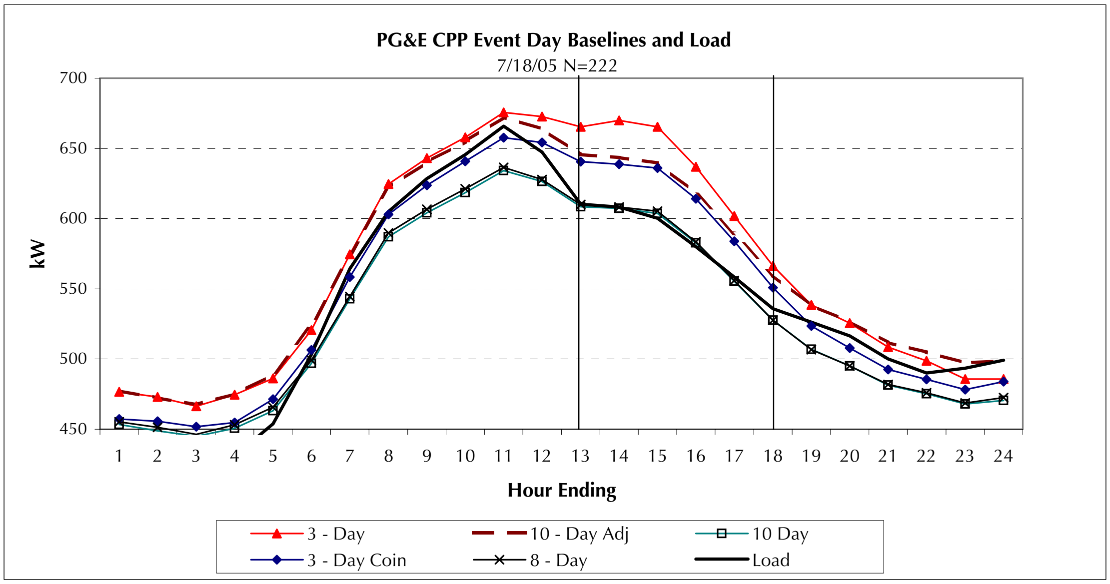
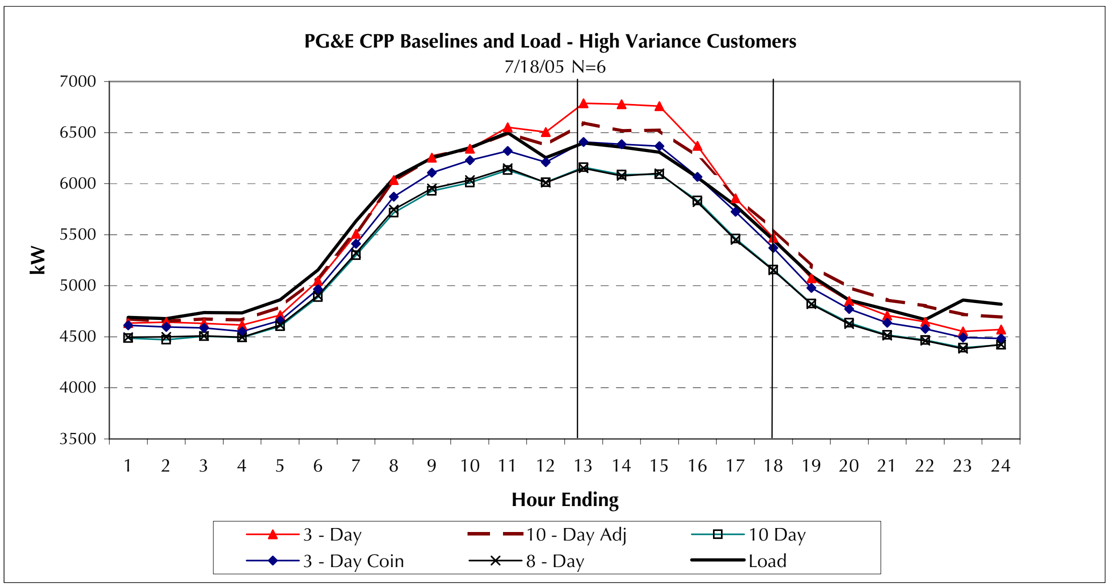
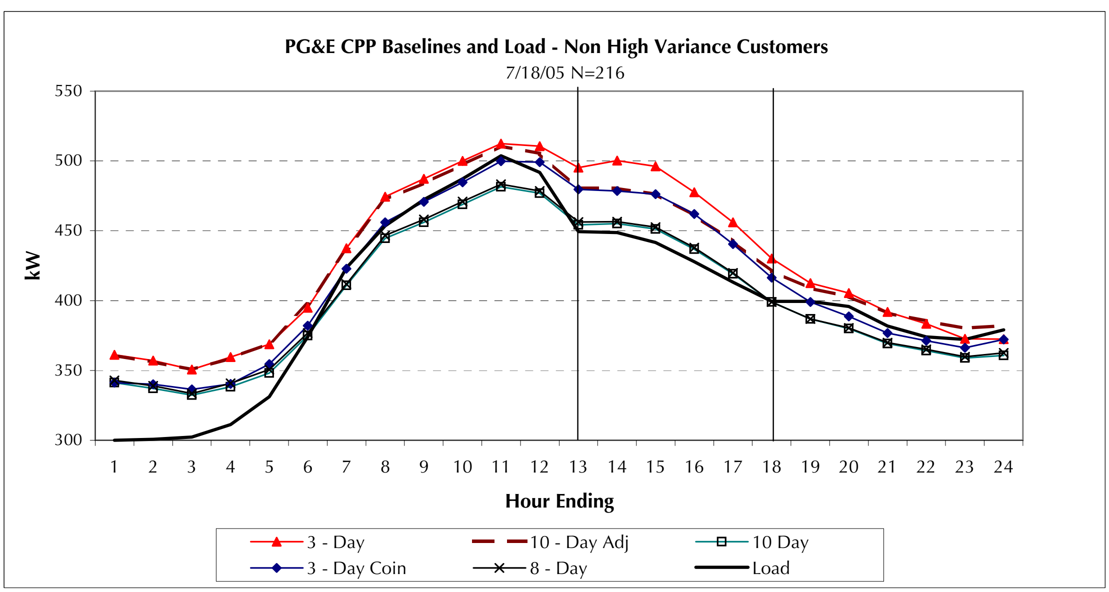


Exhibit D3-4 (Cont.)
PGE CPP Event Day Baselines and Load







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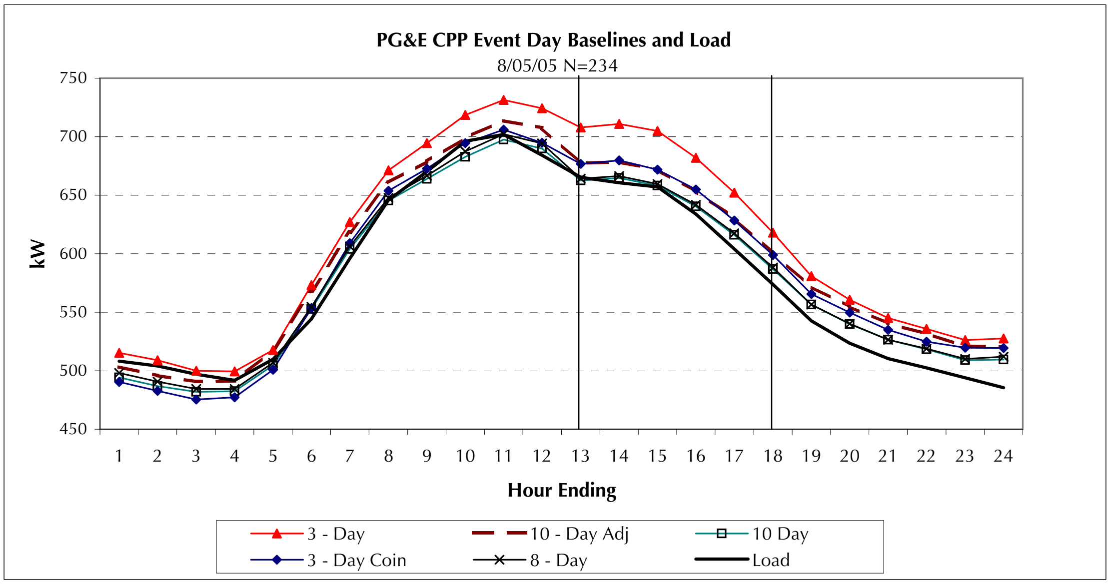
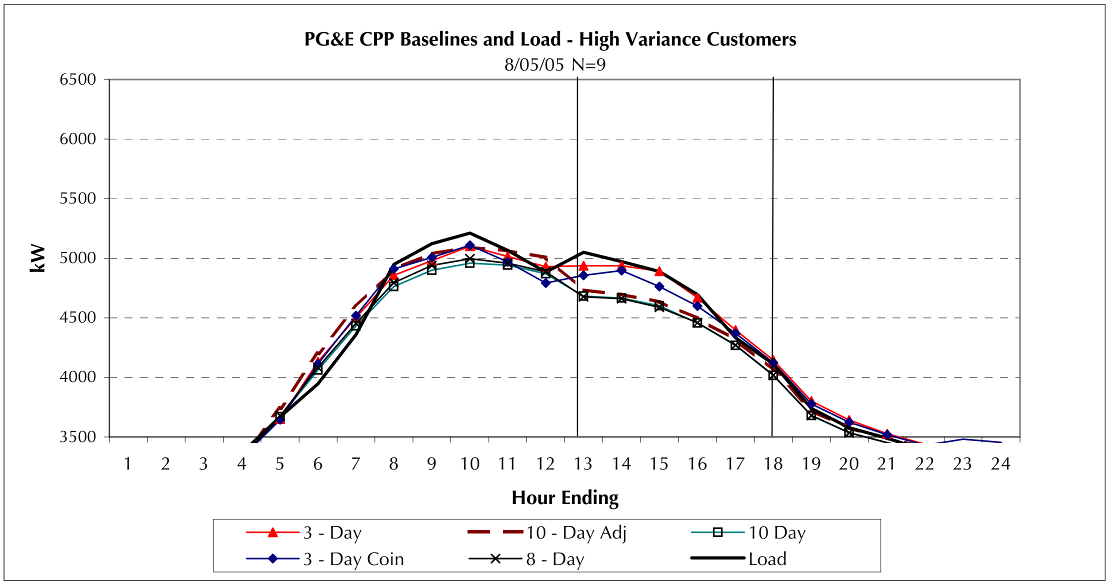
PGE CPP Event Day Baselines and Load





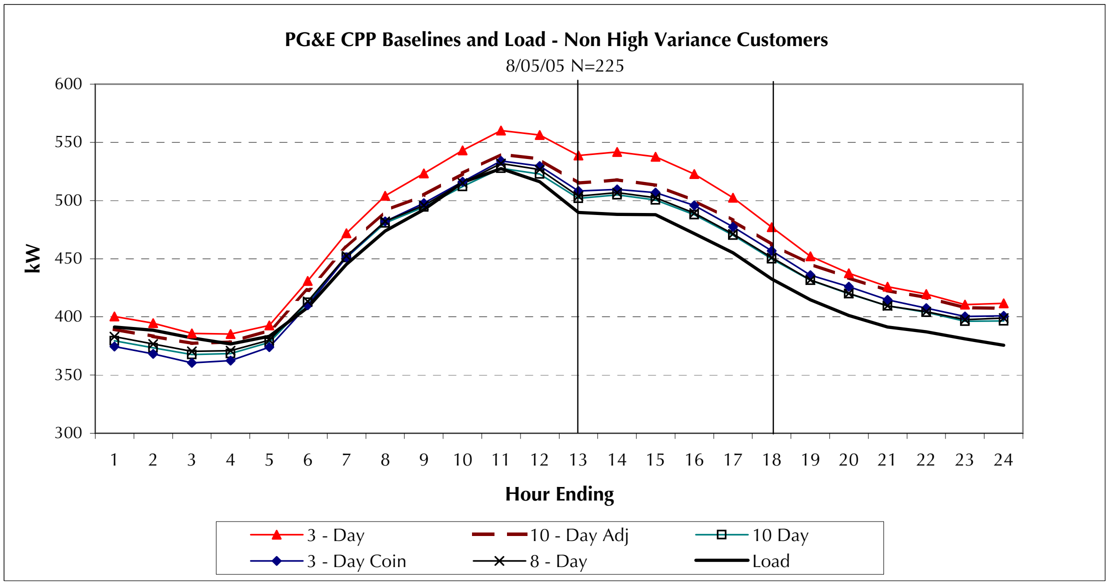
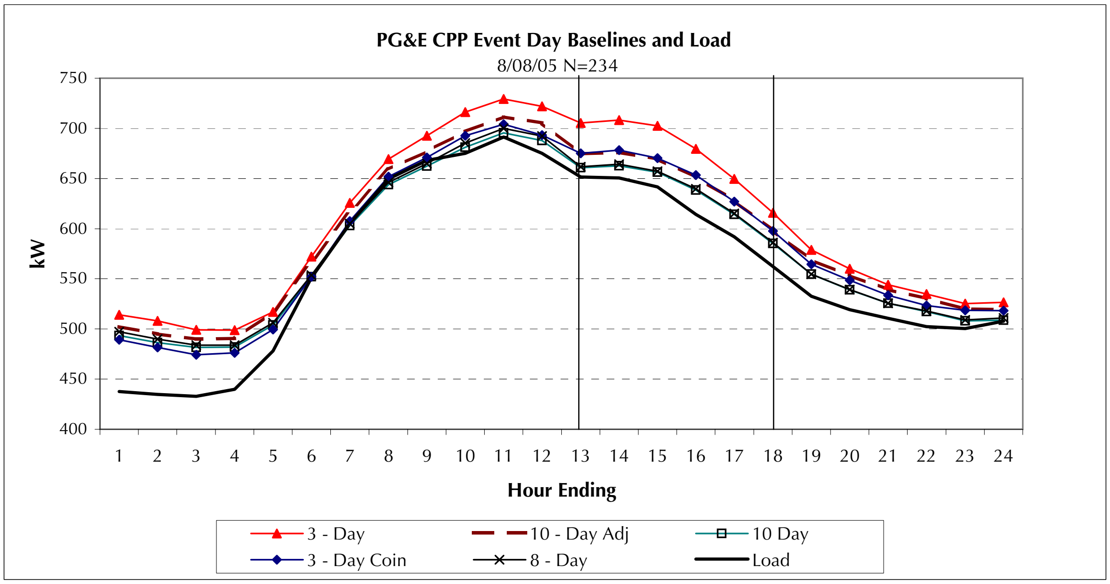
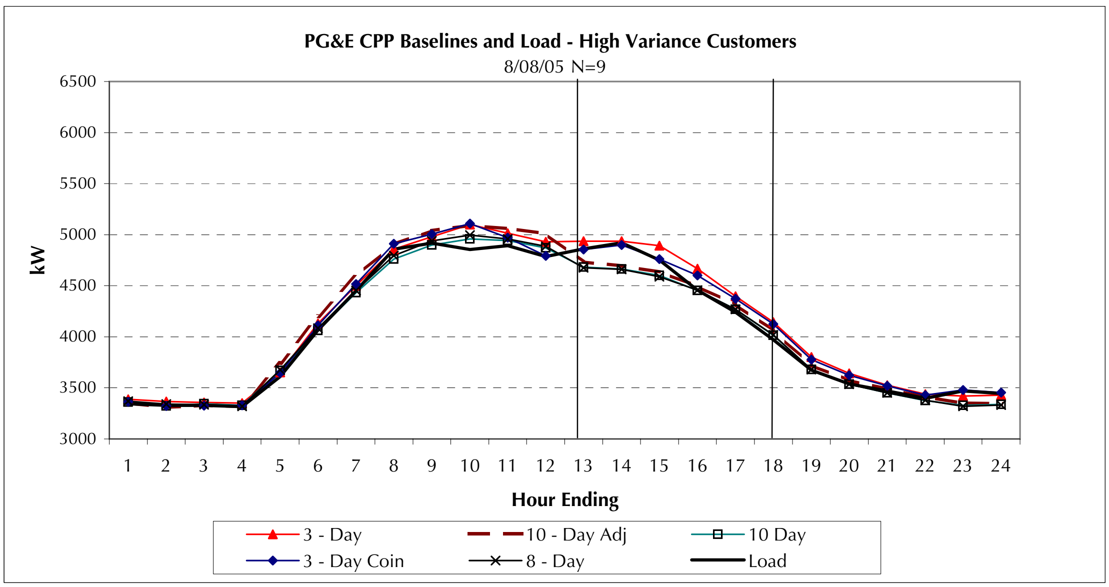


Exhibit D3-4 (Cont.)
PGE CPP Event Day Baselines and Load





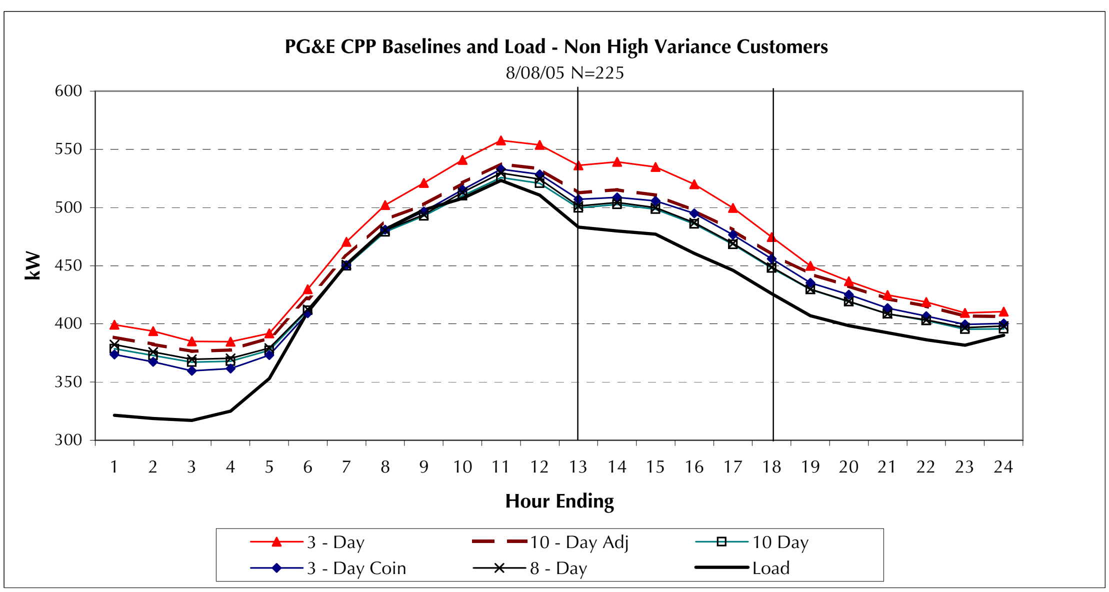
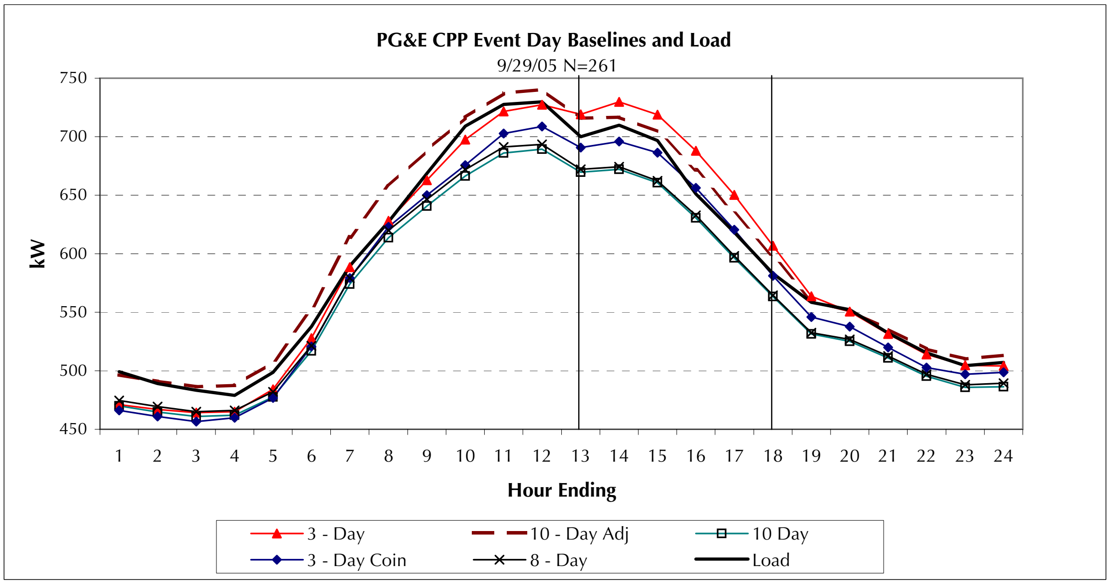
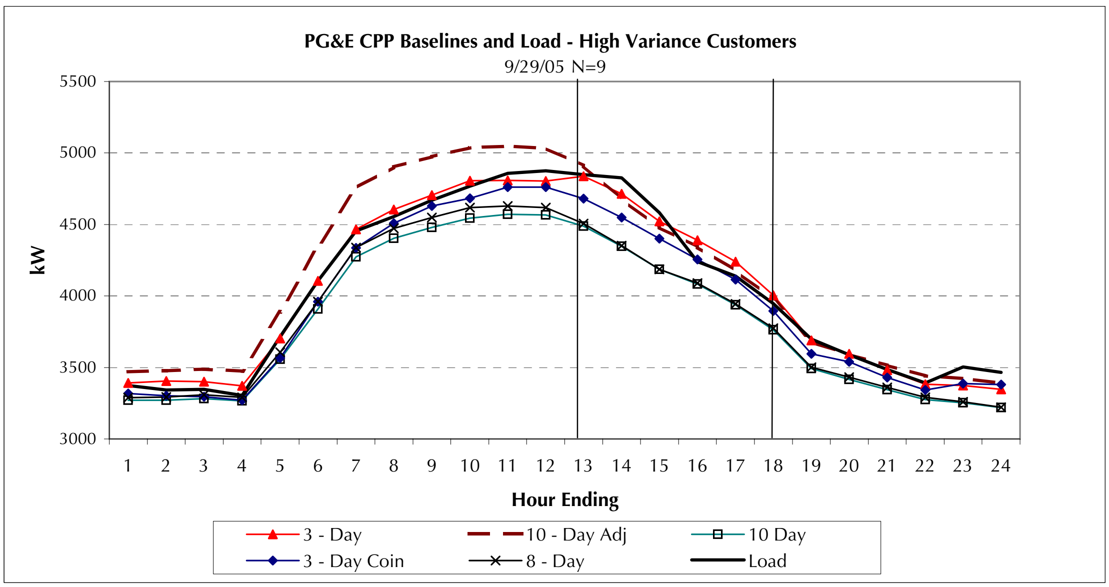


Exhibit D3-4 (Cont.)
PGE CPP Event Day Baselines and Load





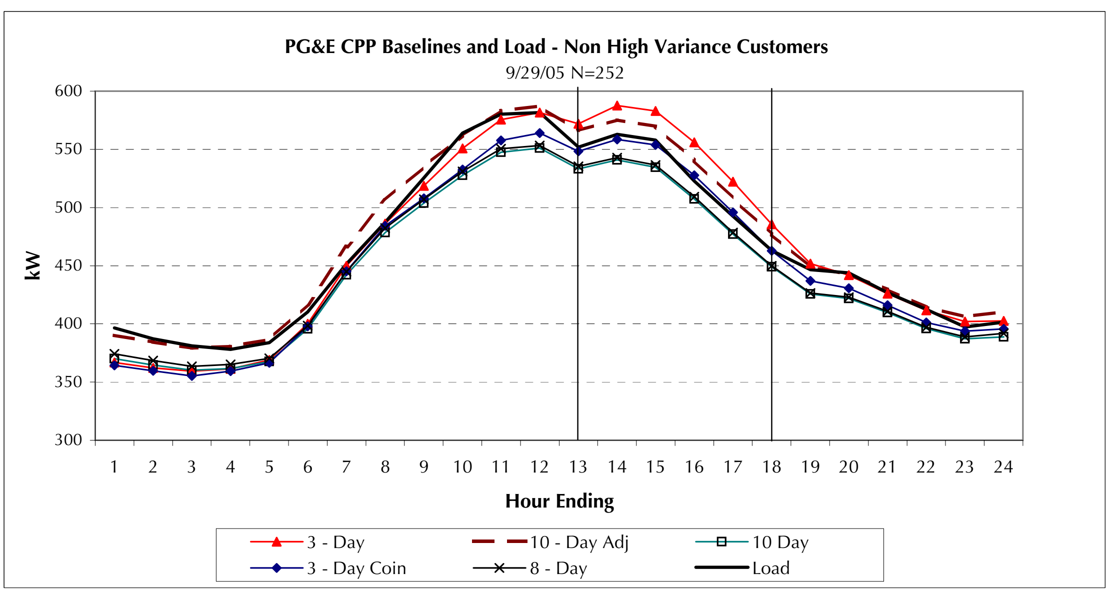


Exhibit D3-5
SCE CPP Event Day Baselines and Load

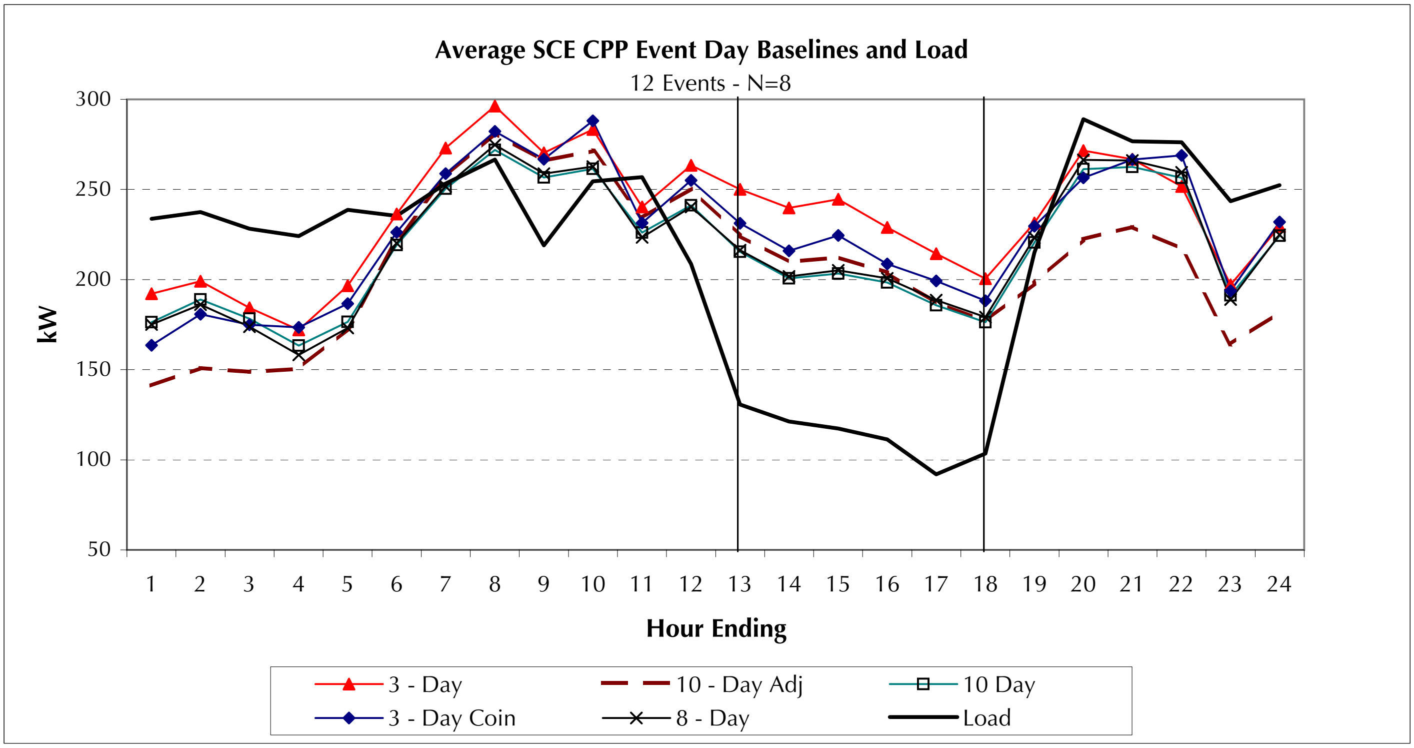
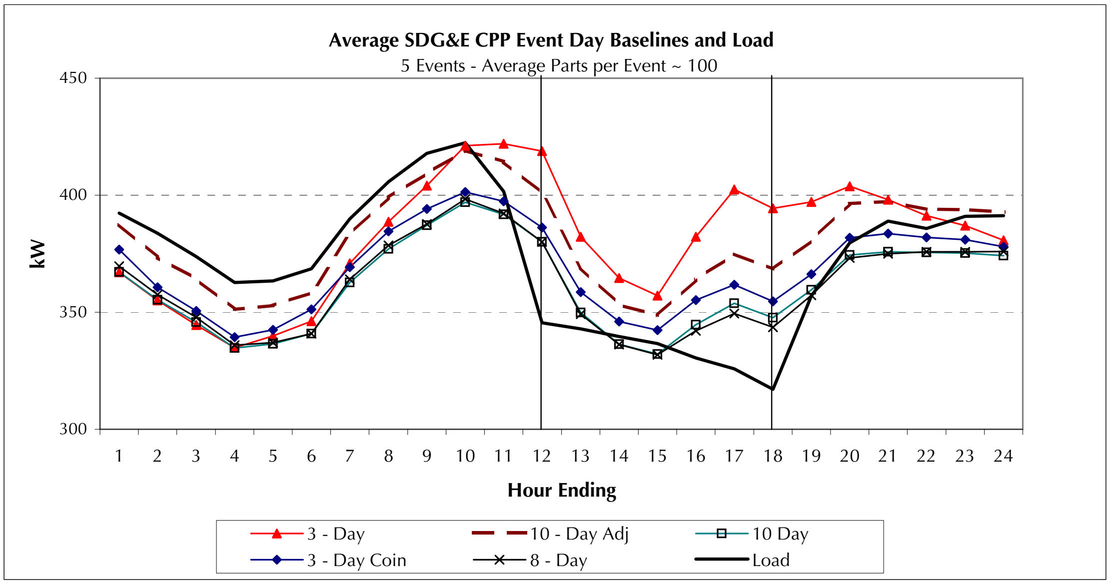
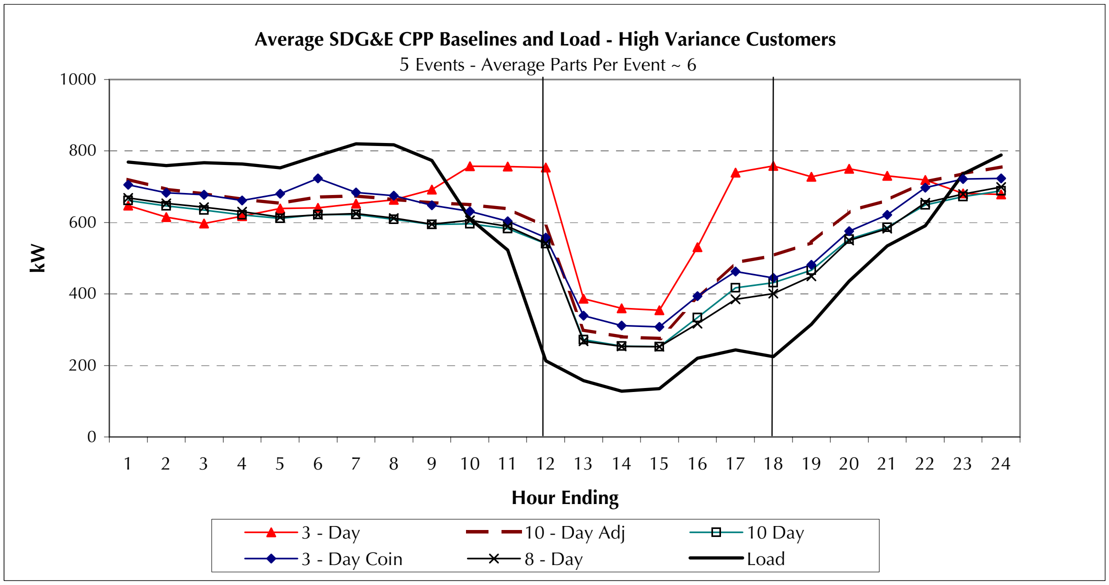
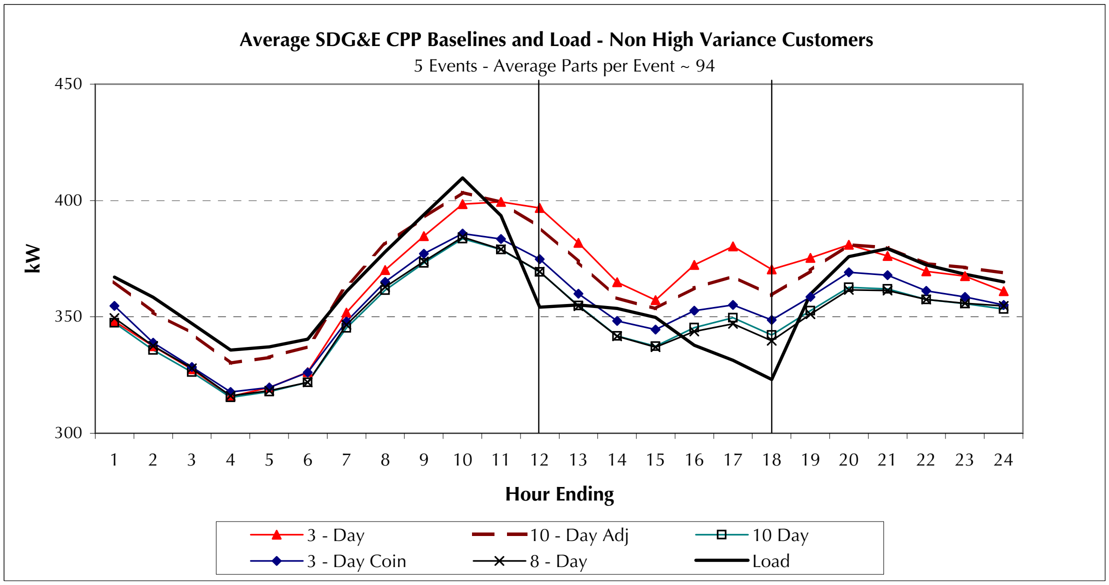


Exhibit D3-6
SDG&E CPP Event Day Baselines and Load







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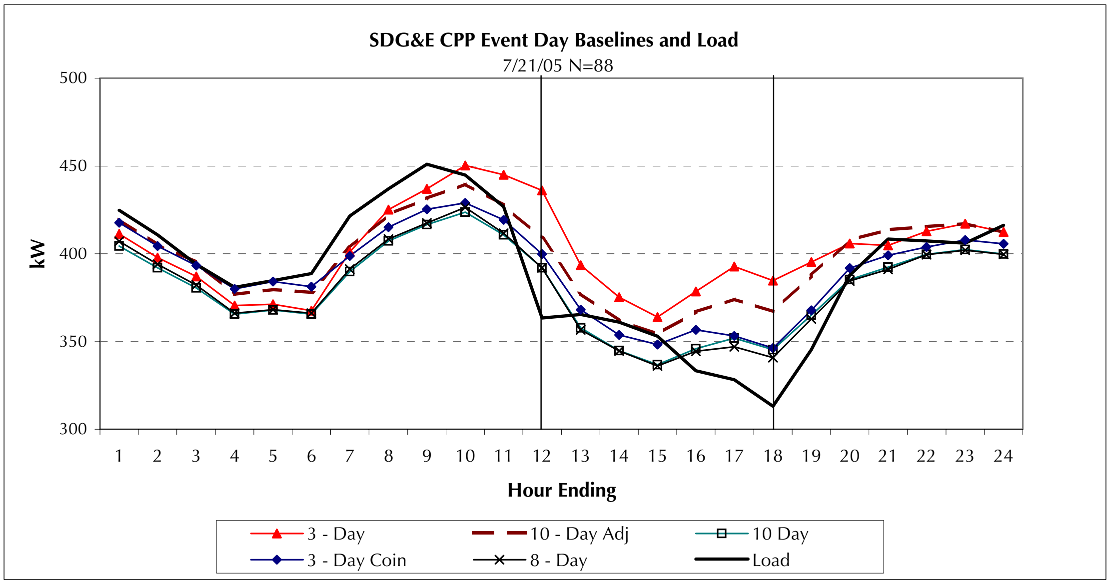
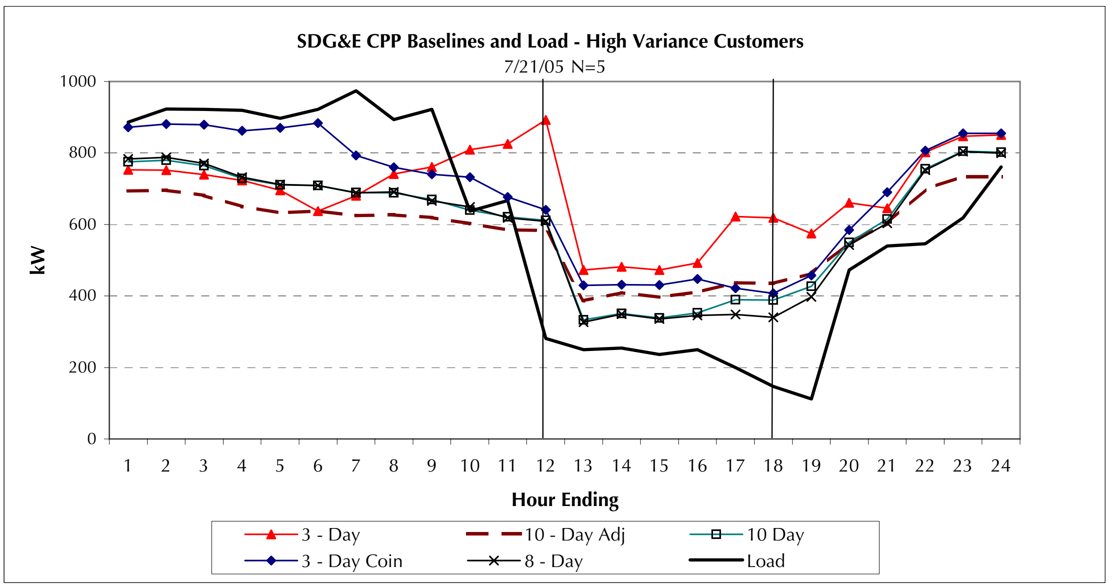
SDG&E CPP Event Day Baselines and Load





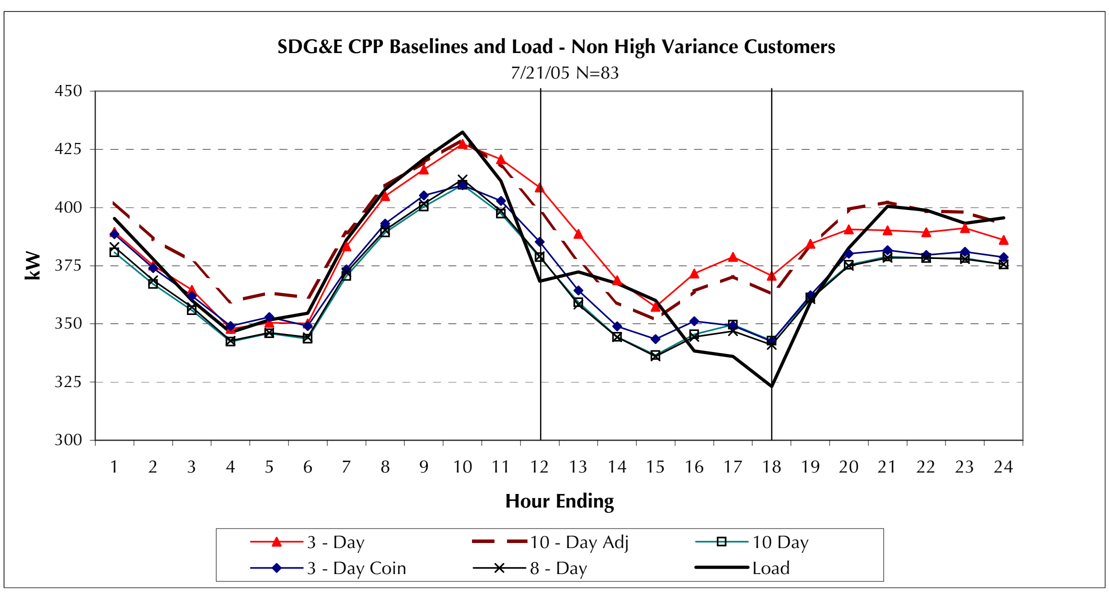
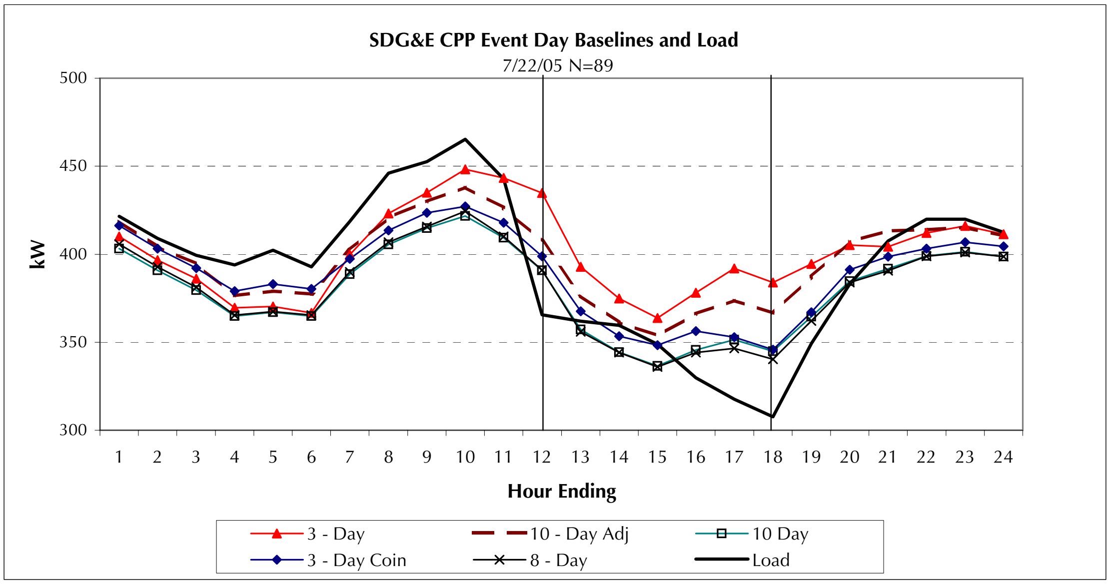
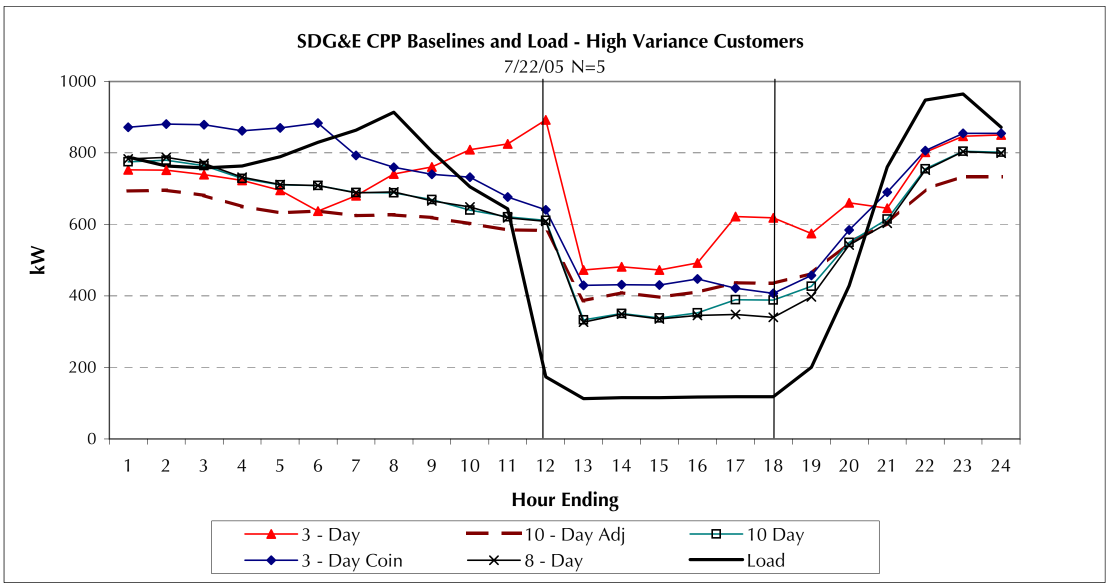


Exhibit D3-6 (Cont.)
SDG&E CPP Event Day Baselines and Load





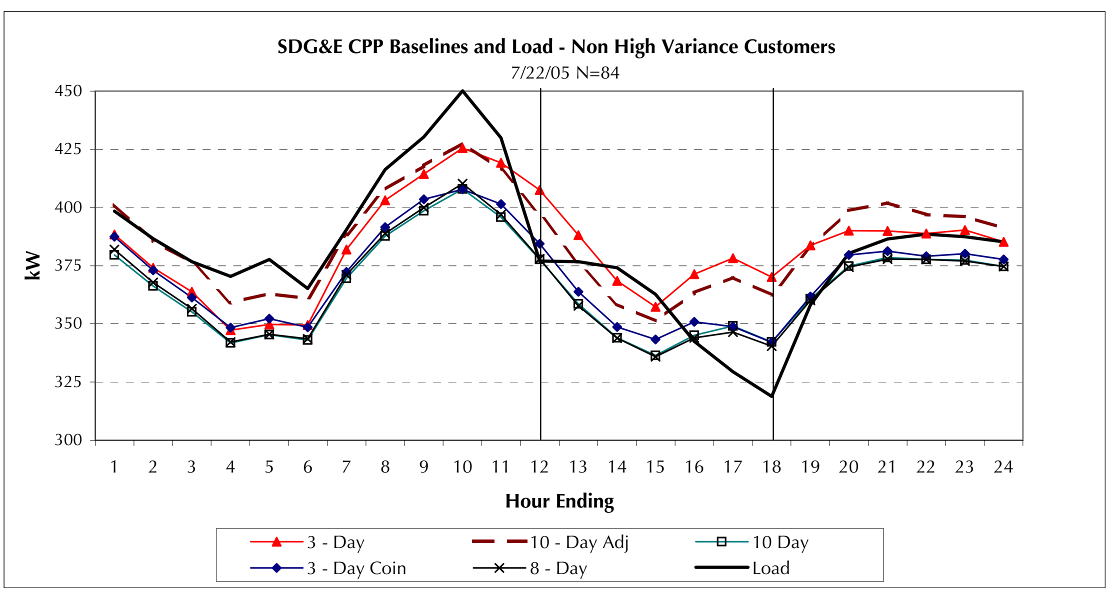
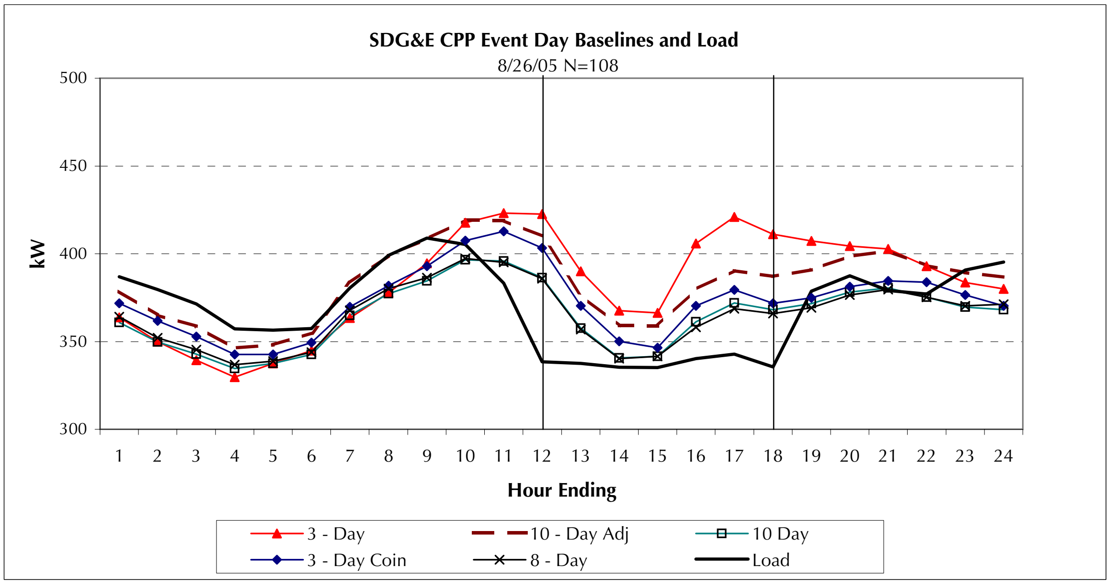
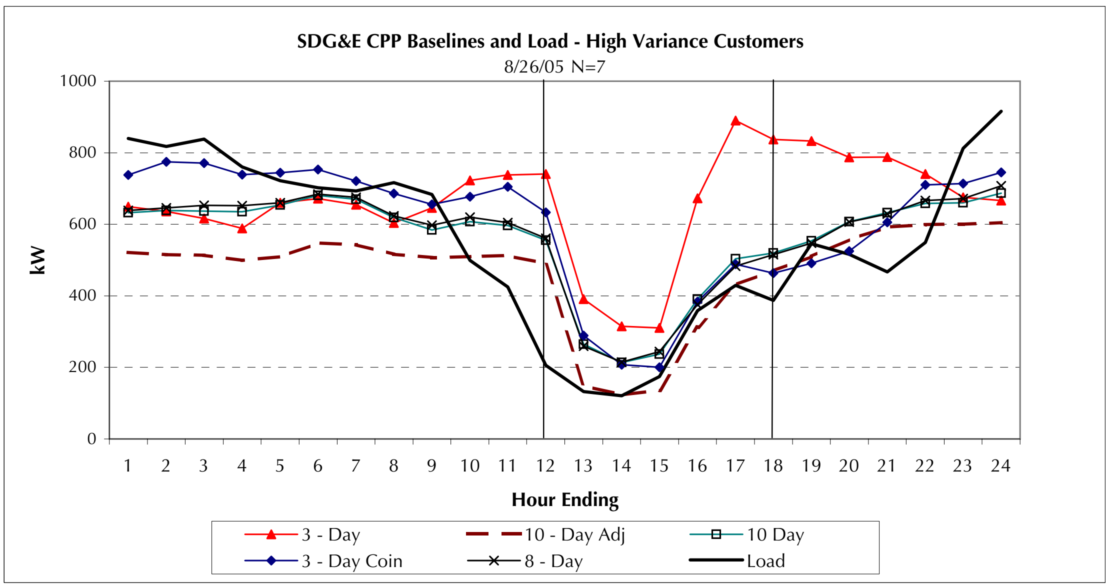


Exhibit D3-6 (Cont.)
SDG&E CPP Event Day Baselines and Load





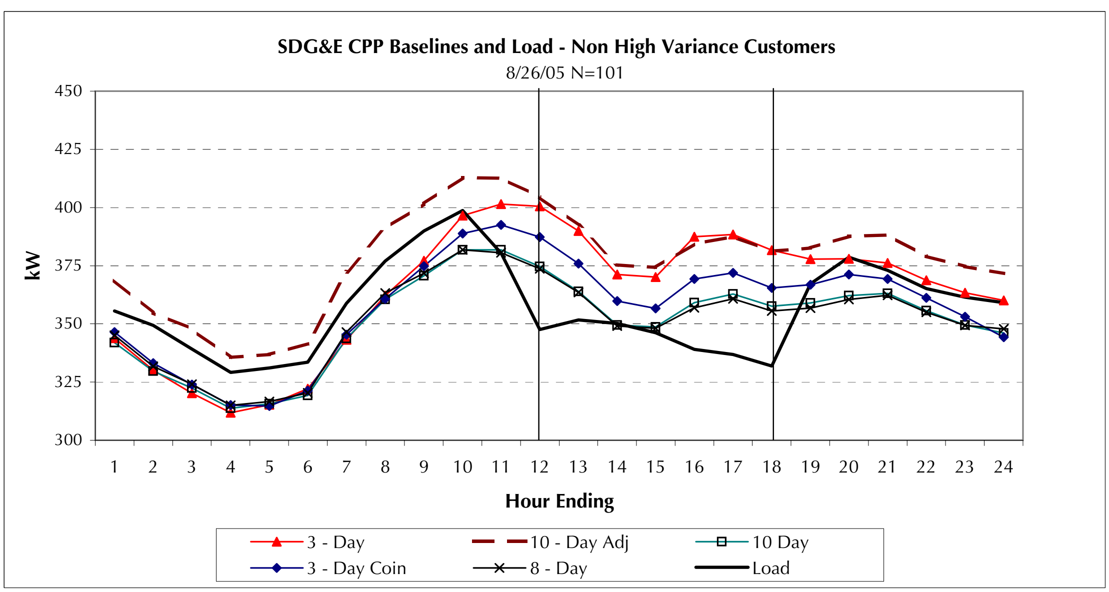
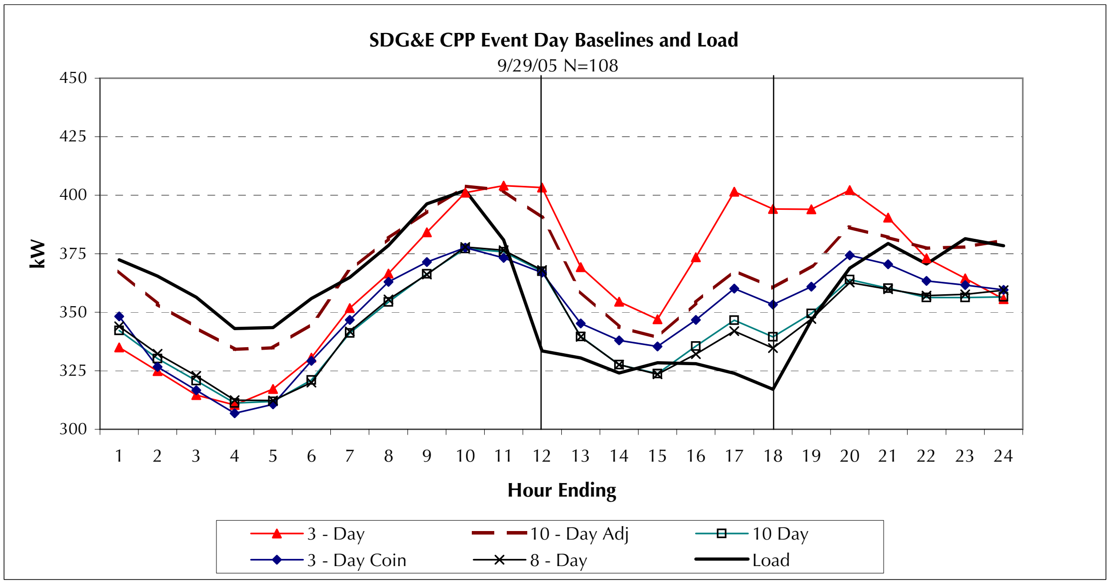
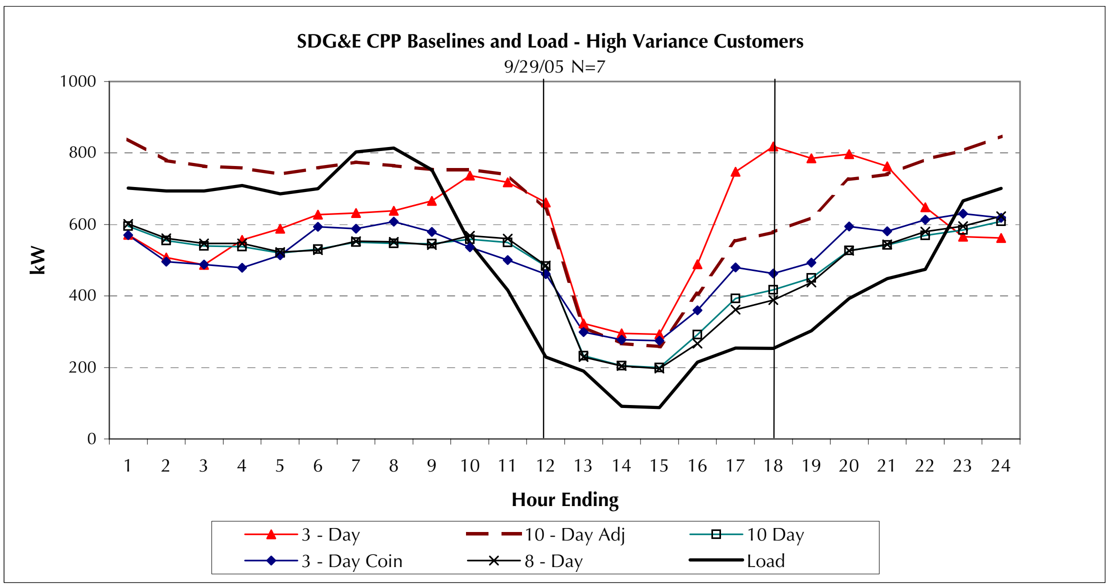
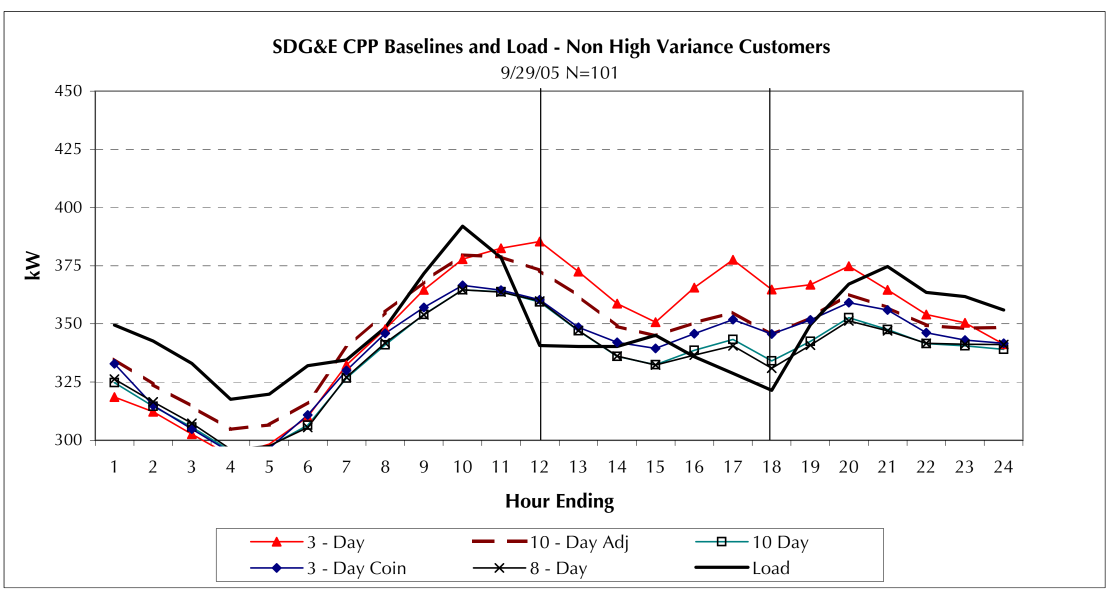


Exhibit D3-6 (Cont.)
SDG&E CPP Event Day Baselines and Load







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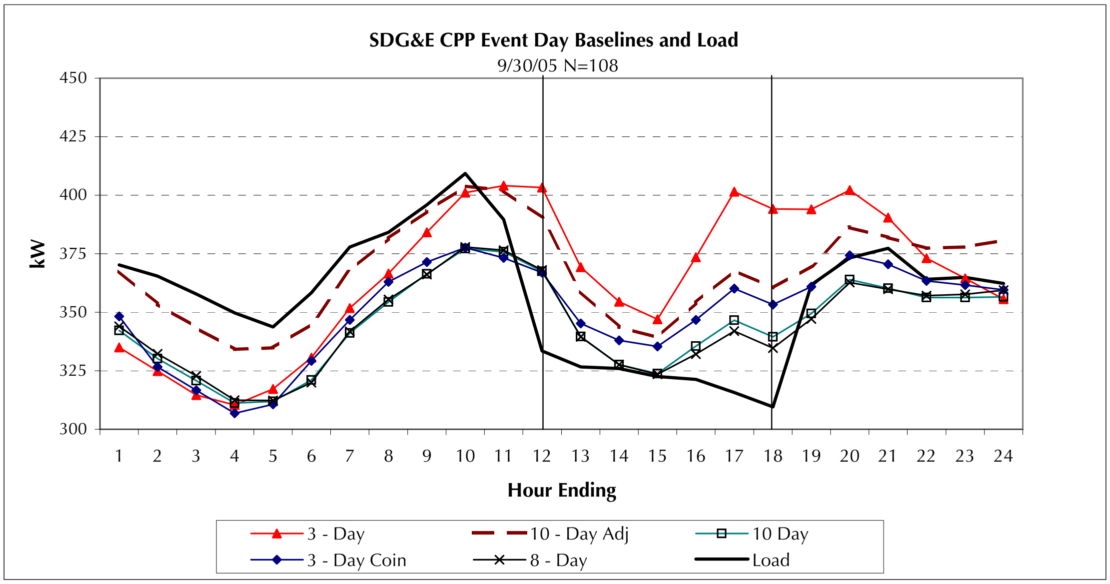
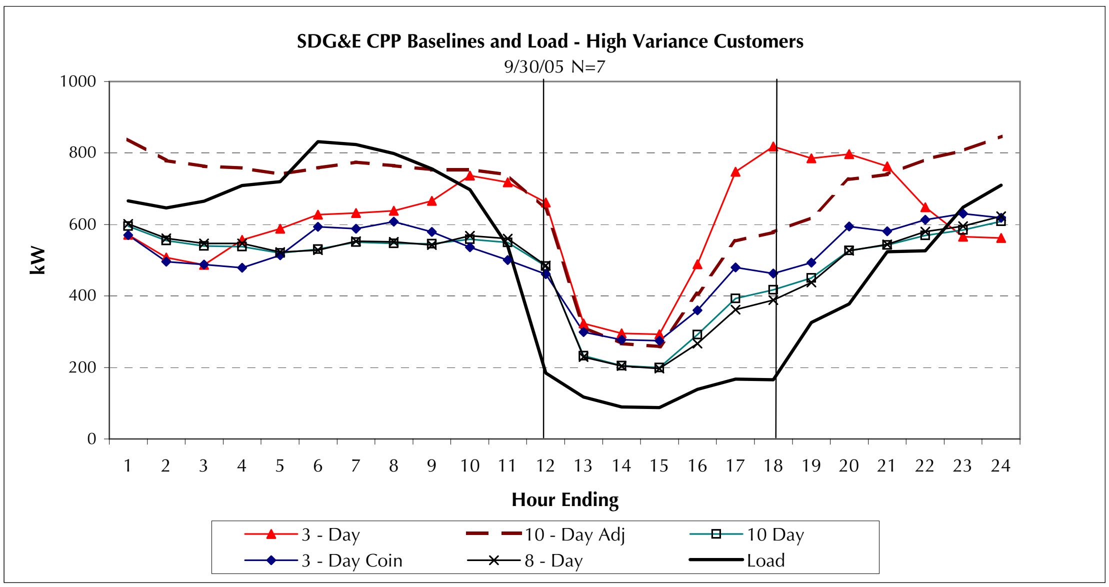
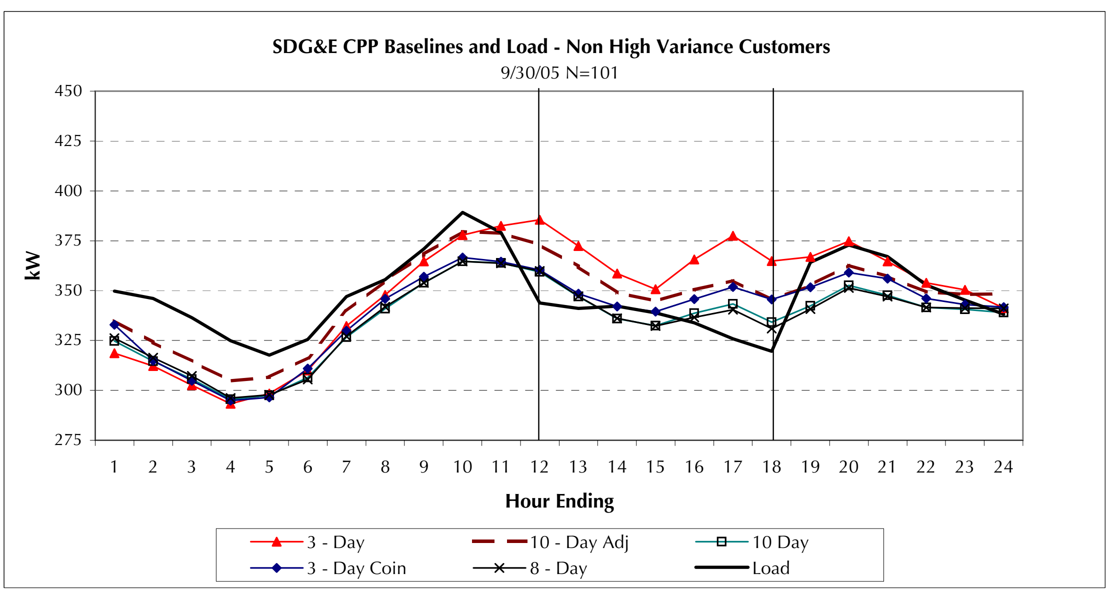
SDG&E CPP Event Day Baselines and Load







D4. CPP and DBP Hourly Impact Estimates

D4. CPP AND DBP HOURLY IMPACT ESTIMATES

The CPP and DBP Hourly Impact Estimates included in Appendix D4 contain the average hourly kW load reduction estimates for an entire event day (including both event and non-event hours) based on the 10-Day Adjusted baseline. The impacts in these tables are calculated as the average load reduction across all summer 2005 events for which participant and bid data were available.

Calculating the hourly impact estimates across all events requires first calculating the sum of the estimated base load and the sum of the actual event day load across all event participants for each hour of the event days. In these tables CPP event participants include all customers enrolled in the CPP program as of the day the event notification is sent out and DBP event participants include all DBP participants who placed a bid for a particular event. Load for DBP participants is included for all event day hours regardless of the hours for which they bid. The difference between these sums for each hour provides the hourly impact estimates.

The Exhibits in this Appendix include the following:

- D4-1 Hourly kW Impact Estimates based on 10-Day Adjusted Baseline over an Entire Event Day based on the Average Event Performance over all CPP Participants (includes spillover)
- D4-2 Hourly kW Impact Estimates based on 10-Day Adjusted Baseline over an Entire Event Day based on the Average Event Performance over all DBP Participants (includes spillover)

Exhibit D4-1
Hourly kW Impact Estimates based on 10-Day Adjusted Baseline over an Entire Event Day based on the Average Event Performance over all CPP Participants (includes spillover)

	CPP Hourly Impact Estimates (kW) based on 10-Day Adjusted Baseline								
	PG&E			SCE			SDG&E		
Hour	Estimated Base Load	Event Day Load	Estimated Impact	Estimated Base Load	Event Day Load	Estimated Impact	Estimated Base Load	Event Day Load	Estimated Impact
1	97,158	94,778	2,380	1,130	1,869	-740	38,062	38,534	-473
2	96,003	94,075	1,928	1,208	1,900	-692	36,676	37,678	-1,002
3	95,028	92,854	2,174	1,191	1,825	-634	35,782	36,699	-917
4	96,110	93,126	2,984	1,204	1,793	-589	34,495	35,617	-1,122
5	99,959	96,509	3,450	1,382	1,909	-527	34,651	35,684	-1,033
6	108,571	105,258	3,312	1,775	1,882	-107	35,183	36,199	-1,016
7	119,247	115,924	3,322	2,057	2,026	31	37,627	38,293	-666
8	128,830	124,318	4,512	2,251	2,132	119	39,184	39,842	-657
9	132,741	128,985	3,756	2,127	1,752	375	40,191	41,035	-843
10	136,264	133,160	3,104	2,171	2,037	135	41,160	41,479	-319
11	139,785	136,614	3,170	1,874	2,055	-181	40,683	39,442	1,241
12	137,873	133,024	4,849	2,004	1,670	335	40,173	34,617	5,557
13	132,710	125,792	6,918	1,794	1,045	749	36,985	34,355	2,630
14	132,407	125,602	6,804	1,677	970	707	35,403	34,035	1,368
15	131,074	123,784	7,289	1,700	938	761	34,937	33,722	1,215
16	125,887	118,181	7,706	1,631	891	740	36,468	33,112	3,356
17	119,526	112,336	7,190	1,497	736	761	37,562	32,651	4,911
18	113,131	106,647	6,484	1,414	828	586	36,912	31,767	5,145
19	108,551	103,885	4,667	1,584	1,721	-137	38,132	35,774	2,358
20	106,365	102,237	4,128	1,779	2,312	-533	39,719	38,041	1,678
21	103,644	99,663	3,982	1,834	2,214	-380	39,810	38,974	836
22	102,026	98,136	3,890	1,736	2,210	-474	39,475	38,657	818
23	100,612	97,230	3,382	1,313	1,947	-635	39,464	39,178	286
24	101,319	97,973	3,345	1,456	2,018	-562	39,361	39,205	156

Exhibit D4-2

Hourly kW Impact Estimates based on 10-Day Adjusted Baseline over an Entire Event Day based on the Average Event Performance over all DBP Participants (includes spillover)

	DBP Hourly Impact Estimates (kW) based on 10-Day Adjusted Baseline								
	PG&E (10 Events*)			SCE (12 Events**)			SDG&E (12 Events***)		
Hour	Estimated Base Load	Event Day Load	Estimated Impact	Estimated Base Load	Event Day Load	Estimated Impact	Estimated Base Load	Event Day Load	Estimated Impact
1	38,394	40,986	-2,592	64,811	66,705	-1,894	2,912	2,836	76
2	37,826	40,306	-2,480	64,373	66,258	-1,886	2,839	2,768	71
3	38,145	39,452	-1,308	63,968	65,161	-1,193	2,801	2,723	78
4	38,330	38,666	-336	63,684	65,120	-1,436	2,786	2,710	76
5	38,618	39,306	-688	64,738	66,797	-2,059	2,801	2,725	77
6	38,900	39,504	-604	67,572	68,535	-963	3,367	3,280	86
7	39,371	39,925	-554	71,189	71,448	-259	4,950	4,769	181
8	40,193	40,360	-167	75,012	74,228	784	5,304	5,152	152
9	41,882	40,020	1,862	77,901	77,061	840	5,461	5,267	194
10	43,308	41,000	2,308	79,694	78,307	1,388	5,661	5,355	305
11	43,972	41,156	2,816	80,541	78,805	1,736	5,645	5,403	242
12	42,458	36,782	5,676	79,207	77,644	1,562	5,692	5,455	237
13	40,159	30,787	9,372	78,498	74,322	4,176	5,381	5,208	173
14	40,072	30,946	9,126	79,130	74,171	4,959	4,823	4,700	123
15	39,830	30,518	9,312	78,770	75,205	3,565	4,419	3,957	461
16	39,832	30,081	9,751	78,133	74,548	3,585	4,242	3,813	429
17	39,923	30,222	9,701	75,721	74,246	1,475	4,039	3,667	371
18	39,021	30,009	9,011	73,020	73,286	-266	3,823	3,512	310
19	40,576	33,703	6,872	71,587	72,326	-739	3,665	3,365	300
20	41,801	36,048	5,753	71,277	71,080	197	3,520	3,290	230
21	41,501	39,721	1,780	71,377	72,998	-1,621	3,503	3,301	202
22	40,632	40,448	184	70,855	72,724	-1,869	3,462	3,248	214
23	39,693	41,188	-1,495	68,987	70,607	-1,620	3,342	3,168	174
24	38,562	40,867	-2,304	67,346	68,634	-1,288	3,217	3,012	205

* First 7 events were excluded due to missing bids

** One event was dropped due to missing bids

*** Event Hrs Varied by Event

D5. CPP and DBP Regression Statistics

D5. CPP AND DBP REGRESSION STATISTICS

The following two tables provide some of the key statistics resulting from the High Load High Variance (HLHV) analysis performed as part of the regression modeling based impact evaluation. Similar tables without the HLHV Breakdown are provided in Chapter 7.

Exhibit D5-1
CPP HLHV Regression Results Summary
HLHV Customers versus the Non-HLHV Customers

CPP HLHV Regression Results	Utility					
	PG&E		SCE		SDG&E	
High Load-High Variance Breakdown	**HLHV**	**Non-HLHV**	**HLHV***	**Non-HLHV**	**HLHV**	**Non-HLHV**
Number of regression equations (customers)	8	254	n/a	8	6	99
Estimated Program Impacts						
Total kW Savings	**-53**	**200**	**n/a**	**40**	**42**	**84**
Corresponding t-value	3.4	10.3	n/a	10.7	6.5	16.5
Total Percentage Reduction	**-3%**	**4%**	**n/a**	**34%**	**48%**	**7%**

* SCE Population of CPP participants consisted of only 8 customers and so no HLHV analysis was performed.

Exhibit D5-2
DBP HLHV Regression Results Summary
HLHV Customers versus the Non-HLHV Customers

DBP HLHV Regression Results	Utility					
	PG&E		SCE		SDG&E	
High Load-High Variance Breakdown	**HLHV**	**Non-HLHV**	**HLHV**	**Non-HLHV**	**HLHV***	**Non-HLHV**
Number of regression equations (customers)	15	53	9	84	n/a	23
Estimated Program Impacts						
Total kW Savings	**150**	**77**	**36**	**137**	**n/a**	**9**
Corresponding t-value	7.1	16.3	1.3	21.6	n/a	16.5
Total Bid Realization Rate	9%	29%	5%	27%	n/a	7%
Total Percentage Reduction	**9%**	**7%**	**1%**	**4%**	**n/a**	**6%**

* No SDG*E DBP participants were flagged as HLHV by the algorithm

D6. DRP Hourly Impact Tables

D6. DRP HOURLY IMPACT TABLES

The DRP Hourly Impact Tables included in Appendix D6 contain the MW impact estimates for each hour of every event during the summer of 2005 for each of the three utilities. The hourly impact estimates for each program participant are calculated as the difference between the estimated hourly base load for the participant, estimated using five different representative day baseline methods, and the actual hourly event day load[1]. The overall program impact for a given event hour is then simply the sum of the hourly impacts across all DRP participants who nominated load for a given event within a given service territory for a particular event:

$$\text{Im}\,pact_t = \sum_n \left(k\hat{W}_{n,t} - kW_{n,t}\right)$$

where,

Impact$_t$ = Difference between the estimated base load and the actual load at time *t*,

$k\hat{W}_{n,t}$ = Estimated base load of customer *n* at time *t*, and

$kW_{n,t}$ = Actual load of customer *n* at time *t*.

The tables in this appendix include the hourly impact estimates based on counting all program impacts (both positive and negative).

The Exhibits in this Appendix include the following:

- D6-1 Hourly Impact Estimates for PG&E DRP Participants – Summer 2005 Events
- D6-2 Hourly Impact Estimates for SCE DRP Participants – Summer 2005 Events
- D6-3 Hourly Impact Estimates for SDG&E DRP Participants – Summer 2005 Events

[1] The five representative day baselines included in the hourly impact tables are the DRP 8-Day Adjusted, QC 8-Day Adjusted, QC 8-Day, 10-Day Adjusted and 10-Day baselines. Each of these representative day baselines is described in Chapter 6.

Exhibit D6-1
Hourly Impact Estimates for PG&E DRP Participants –Events 1-13

Utility	Event	Baseline	Hourly DRP Impacts (MW)						Percent Reduction						Nomination Realization Rate						Utility
			1-2	2-3	3-4	4-5	5-6	6-7	1-2	2-3	3-4	4-5	5-6	6-7	1-2	2-3	3-4	4-5	5-6	6-7	Reported
PG&E	6/30/05	DRP 8-Day Adj	.	316	279	284	284	.	.	59%	46%	57%	56%	.	.	158%	122%	142%	142%	.	210.0
PG&E	6/30/05	QC 8-Day Adj	.	317	281	285	286	.	.	59%	47%	57%	57%	.	.	159%	123%	143%	143%	.	-
PG&E	6/30/05	QC 8-Day	.	228	196	203	202	.	.	51%	38%	49%	48%	.	.	114%	86%	101%	101%	.	-
PG&E	6/30/05	10-Day Adj	.	327	276	276	277	.	.	60%	46%	57%	56%	.	.	164%	121%	138%	139%	.	-
PG&E	6/30/05	10-Day	.	237	191	196	196	.	.	52%	37%	48%	47%	.	.	119%	84%	98%	98%	.	-
PG&E	7/12/05	DRP 8-Day Adj	.	217	214	202	187	.	.	34%	32%	31%	33%	.	.	103%	92%	87%	87%	.	227.3
PG&E	7/12/05	QC 8-Day Adj	.	293	279	267	257	.	.	41%	38%	37%	40%	.	.	139%	120%	115%	119%	.	-
PG&E	7/12/05	QC 8-Day	.	175	165	158	152	.	.	29%	26%	26%	28%	.	.	83%	71%	68%	70%	.	-
PG&E	7/12/05	10-Day Adj	.	306	283	269	258	.	.	42%	38%	38%	40%	.	.	145%	121%	115%	119%	.	-
PG&E	7/12/05	10-Day	.	189	170	161	156	.	.	31%	27%	26%	29%	.	.	90%	73%	69%	72%	.	-
PG&E	7/13/05	DRP 8-Day Adj	.	.	171	205	.	.	.	.	25%	32%	.	.	.	.	73%	87%	.	.	234.4
PG&E	7/13/05	QC 8-Day Adj	.	.	238	275	.	.	.	.	32%	39%	.	.	.	.	102%	117%	.	.	-
PG&E	7/13/05	QC 8-Day	.	.	124	165	.	.	.	.	20%	27%	.	.	.	.	53%	71%	.	.	-
PG&E	7/13/05	10-Day Adj	.	.	242	277	.	.	.	.	33%	39%	.	.	.	.	103%	118%	.	.	-
PG&E	7/13/05	10-Day	.	.	130	169	.	.	.	.	21%	28%	.	.	.	.	55%	72%	.	.	-
PG&E	7/14/05	DRP 8-Day Adj	119	224	229	202	.	.	19%	37%	35%	32%	.	.	59%	109%	102%	90%	.	.	214.7
PG&E	7/14/05	QC 8-Day Adj	213	325	298	276	.	.	30%	46%	41%	39%	.	.	105%	158%	132%	122%	.	.	-
PG&E	7/14/05	QC 8-Day	93	207	183	165	.	.	16%	35%	30%	28%	.	.	46%	101%	81%	73%	.	.	-
PG&E	7/14/05	10-Day Adj	220	338	301	278	.	.	31%	47%	41%	39%	.	.	109%	164%	134%	123%	.	.	-
PG&E	7/14/05	10-Day	104	221	188	168	.	.	17%	36%	30%	28%	.	.	51%	107%	83%	75%	.	.	-
PG&E	7/15/05	DRP 8-Day Adj	.	.	223	232	185	.	.	.	35%	37%	34%	.	.	.	99%	103%	89%	.	219.7
PG&E	7/15/05	QC 8-Day Adj	.	.	306	312	273	.	.	.	42%	44%	43%	.	.	.	136%	139%	131%	.	-
PG&E	7/15/05	QC 8-Day	.	.	192	201	168	.	.	.	31%	34%	32%	.	.	.	85%	89%	81%	.	-
PG&E	7/15/05	10-Day Adj	.	.	310	313	274	.	.	.	42%	45%	43%	.	.	.	138%	139%	131%	.	-
PG&E	7/15/05	10-Day	.	.	197	204	172	.	.	.	32%	34%	33%	.	.	.	87%	91%	82%	.	-
PG&E	7/18/05	DRP 8-Day Adj	.	212	239	261	272	.	.	36%	37%	42%	45%	.	.	103%	106%	116%	120%	.	221.1
PG&E	7/18/05	QC 8-Day Adj	.	326	323	341	361	.	.	46%	44%	48%	52%	.	.	158%	143%	151%	160%	.	-
PG&E	7/18/05	QC 8-Day	.	208	209	231	251	.	.	35%	34%	39%	43%	.	.	101%	92%	102%	111%	.	-
PG&E	7/18/05	10-Day Adj	.	339	326	343	362	.	.	47%	44%	48%	52%	.	.	164%	144%	152%	160%	.	-
PG&E	7/18/05	10-Day	.	222	214	234	254	.	.	37%	34%	39%	43%	.	.	108%	95%	104%	112%	.	-
PG&E	7/25/05	DRP 8-Day Adj	.	115	136	139	138	.	.	22%	23%	24%	24%	.	.	56%	61%	62%	61%	.	220.2
PG&E	7/25/05	QC 8-Day Adj	.	194	201	193	186	.	.	33%	31%	31%	30%	.	.	94%	89%	86%	83%	.	-
PG&E	7/25/05	QC 8-Day	.	149	155	147	141	.	.	27%	26%	25%	25%	.	.	72%	69%	65%	63%	.	-
PG&E	7/25/05	10-Day Adj	.	213	204	195	189	.	.	35%	32%	31%	30%	.	.	103%	91%	87%	84%	.	-
PG&E	7/25/05	10-Day	.	157	147	139	134	.	.	28%	25%	24%	24%	.	.	76%	66%	62%	59%	.	-
PG&E	7/26/05	DRP 8-Day Adj	.	.	253	249	253	.	.	.	44%	44%	45%	.	.	.	113%	111%	113%	.	223.4
PG&E	7/26/05	QC 8-Day Adj	.	.	322	308	308	.	.	.	50%	49%	50%	.	.	.	144%	138%	138%	.	-
PG&E	7/26/05	QC 8-Day	.	.	276	263	263	.	.	.	46%	45%	46%	.	.	.	123%	118%	118%	.	-
PG&E	7/26/05	10-Day Adj	.	.	325	310	311	.	.	.	50%	49%	50%	.	.	.	146%	139%	139%	.	-
PG&E	7/26/05	10-Day	.	.	269	255	256	.	.	.	45%	44%	45%	.	.	.	120%	114%	114%	.	-
PG&E	8/8/05	DRP 8-Day Adj	.	233	275	262	271	.	.	69%	83%	83%	84%	.	.	115%	133%	126%	130%	.	206.5
PG&E	8/8/05	QC 8-Day Adj	.	237	277	266	274	.	.	69%	83%	83%	84%	.	.	117%	133%	128%	132%	.	-
PG&E	8/8/05	QC 8-Day	.	256	294	282	291	.	.	71%	84%	84%	85%	.	.	126%	141%	136%	140%	.	-
PG&E	8/8/05	10-Day Adj	.	246	291	282	288	.	.	70%	84%	84%	85%	.	.	121%	140%	136%	139%	.	-
PG&E	8/8/05	10-Day	.	263	306	297	304	.	.	71%	85%	84%	85%	.	.	130%	147%	143%	146%	.	-
PG&E	8/10/05	DRP 8-Day Adj	.	.	345	337	335	.	.	.	80%	82%	81%	.	.	.	162%	158%	157%	.	212.8
PG&E	8/10/05	QC 8-Day Adj	.	.	283	280	275	.	.	.	77%	79%	77%	.	.	.	133%	131%	129%	.	-
PG&E	8/10/05	QC 8-Day	.	.	268	265	260	.	.	.	76%	79%	76%	.	.	.	126%	125%	122%	.	-
PG&E	8/10/05	10-Day Adj	.	.	288	287	282	.	.	.	77%	80%	78%	.	.	.	135%	135%	133%	.	-
PG&E	8/10/05	10-Day	.	.	272	271	266	.	.	.	76%	79%	77%	.	.	.	128%	127%	125%	.	-
PG&E	8/11/05	DRP 8-Day Adj	.	.	365	343	355	.	.	.	87%	86%	87%	.	.	.	172%	161%	167%	.	212.8
PG&E	8/11/05	QC 8-Day Adj	.	.	313	297	305	.	.	.	85%	84%	86%	.	.	.	147%	140%	143%	.	-
PG&E	8/11/05	QC 8-Day	.	.	298	283	290	.	.	.	84%	84%	85%	.	.	.	140%	133%	136%	.	-
PG&E	8/11/05	10-Day Adj	.	.	318	305	312	.	.	.	85%	85%	86%	.	.	.	149%	143%	146%	.	-
PG&E	8/11/05	10-Day	.	.	301	289	295	.	.	.	85%	84%	85%	.	.	.	142%	136%	139%	.	-
PG&E	8/12/05	DRP 8-Day Adj	.	403	352	333	.	.	.	90%	86%	87%	.	.	.	198%	165%	156%	.	.	209.6
PG&E	8/12/05	QC 8-Day Adj	.	334	309	301	.	.	.	88%	84%	86%	.	.	.	165%	145%	141%	.	.	-
PG&E	8/12/05	QC 8-Day	.	317	294	287	.	.	.	88%	83%	85%	.	.	.	156%	138%	135%	.	.	-
PG&E	8/12/05	10-Day Adj	.	335	314	308	.	.	.	88%	84%	86%	.	.	.	165%	148%	145%	.	.	-
PG&E	8/12/05	10-Day	.	316	298	293	.	.	.	88%	84%	85%	.	.	.	156%	140%	137%	.	.	-
PG&E	8/17/05	DRP 8-Day Adj	.	284	266	257	.	.	.	92%	84%	83%	.	.	.	140%	125%	121%	.	.	209.7
PG&E	8/17/05	QC 8-Day Adj	.	319	280	264	.	.	.	93%	84%	83%	.	.	.	157%	132%	124%	.	.	-
PG&E	8/17/05	QC 8-Day	.	321	284	268	.	.	.	93%	84%	84%	.	.	.	158%	133%	126%	.	.	-
PG&E	8/17/05	10-Day Adj	.	317	283	271	.	.	.	93%	84%	84%	.	.	.	156%	133%	127%	.	.	-
PG&E	8/17/05	10-Day	.	320	288	275	.	.	.	93%	85%	84%	.	.	.	158%	135%	129%	.	.	-

Exhibit D6-1 (con't)
Hourly Impact Estimates for PG&E DRP Participants –Events 14-25 and Summer Average

Utility	Event	Baseline	Hourly DRP Impacts (MW)						Percent Reduction						Nomination Realization Rate						Utility
			1-2	2-3	3-4	4-5	5-6	6-7	1-2	2-3	3-4	4-5	5-6	6-7	1-2	2-3	3-4	4-5	5-6	6-7	Reported
PG&E	8/18/05	DRP 8-Day Adj	.	281	261	249	.	.	.	93%	84%	83%	.	.	.	138%	122%	117%	.	.	209.7
PG&E	8/18/05	QC 8-Day Adj	.	320	282	266	.	.	.	93%	85%	84%	.	.	.	158%	132%	125%	.	.	-
PG&E	8/18/05	QC 8-Day	.	322	285	269	.	.	.	94%	85%	84%	.	.	.	159%	134%	126%	.	.	-
PG&E	8/18/05	10-Day Adj	.	318	285	272	.	.	.	93%	85%	84%	.	.	.	157%	134%	128%	.	.	-
PG&E	8/18/05	10-Day	.	322	289	277	.	.	.	93%	85%	84%	.	.	.	158%	136%	130%	.	.	-
PG&E	8/23/05	DRP 8-Day Adj	.	131	126	122	.	.	.	70%	57%	56%	.	.	.	64%	57%	56%	.	.	214.7
PG&E	8/23/05	QC 8-Day Adj	.	156	142	136	.	.	.	74%	60%	59%	.	.	.	76%	65%	62%	.	.	-
PG&E	8/23/05	QC 8-Day	.	282	252	243	.	.	.	83%	73%	72%	.	.	.	137%	115%	111%	.	.	-
PG&E	8/23/05	10-Day Adj	.	158	144	136	.	.	.	74%	61%	59%	.	.	.	77%	66%	62%	.	.	-
PG&E	8/23/05	10-Day	.	287	256	242	.	.	.	84%	73%	72%	.	.	.	140%	117%	110%	.	.	-
PG&E	8/25/05	DRP 8-Day Adj	.	.	184	184	10	.	.	.	67%	68%	15%	.	.	.	84%	84%	69%	.	150.6
PG&E	8/25/05	QC 8-Day Adj	.	.	183	179	10	.	.	.	67%	67%	14%	.	.	.	84%	81%	68%	.	-
PG&E	8/25/05	QC 8-Day	.	.	251	244	11	.	.	.	74%	74%	16%	.	.	.	114%	111%	75%	.	-
PG&E	8/25/05	10-Day Adj	.	.	187	179	10	.	.	.	68%	67%	14%	.	.	.	85%	81%	68%	.	-
PG&E	8/25/05	10-Day	.	.	256	245	11	.	.	.	74%	74%	15%	.	.	.	117%	112%	74%	.	-
PG&E	8/26/05	DRP 8-Day Adj	.	.	7	8	9	.	.	.	17%	22%	25%	.	.	.	79%	97%	102%	.	8.5
PG&E	8/26/05	QC 8-Day Adj	.	.	7	8	9	.	.	.	18%	22%	25%	.	.	.	82%	98%	103%	.	-
PG&E	8/26/05	QC 8-Day	.	.	7	8	8	.	.	.	17%	21%	24%	.	.	.	79%	95%	99%	.	-
PG&E	8/26/05	10-Day Adj	.	.	7	8	9	.	.	.	18%	22%	25%	.	.	.	82%	98%	103%	.	-
PG&E	8/26/05	10-Day	.	.	7	8	8	.	.	.	17%	21%	24%	.	.	.	78%	95%	99%	.	-
PG&E	9/6/05	DRP 8-Day Adj	.	.	222	215	213	.	.	.	78%	78%	79%	.	.	.	104%	101%	100%	.	204.5
PG&E	9/6/05	QC 8-Day Adj	.	.	207	200	200	.	.	.	77%	77%	78%	.	.	.	97%	94%	94%	.	-
PG&E	9/6/05	QC 8-Day	.	.	209	202	202	.	.	.	77%	77%	78%	.	.	.	98%	95%	95%	.	-
PG&E	9/6/05	10-Day Adj	.	.	204	197	196	.	.	.	77%	76%	78%	.	.	.	96%	92%	92%	.	-
PG&E	9/6/05	10-Day	.	.	206	199	198	.	.	.	77%	77%	78%	.	.	.	97%	93%	93%	.	-
PG&E	9/19/05	DRP 8-Day Adj	.	224	217	210	.	.	.	83%	71%	71%	.	.	.	108%	100%	96%	.	.	214.3
PG&E	9/19/05	QC 8-Day Adj	.	197	194	188	.	.	.	81%	69%	68%	.	.	.	95%	89%	86%	.	.	-
PG&E	9/19/05	QC 8-Day	.	282	276	269	.	.	.	86%	76%	75%	.	.	.	137%	127%	123%	.	.	-
PG&E	9/19/05	10-Day Adj	.	204	201	195	.	.	.	82%	69%	69%	.	.	.	99%	92%	89%	.	.	-
PG&E	9/19/05	10-Day	.	293	288	280	.	.	.	86%	77%	76%	.	.	.	142%	132%	128%	.	.	-
PG&E	9/20/05	DRP 8-Day Adj	247	231	221	217	.	.	90%	84%	71%	72%	.	.	122%	112%	101%	99%	.	.	211.8
PG&E	9/20/05	QC 8-Day Adj	215	198	193	190	.	.	89%	82%	69%	69%	.	.	106%	96%	88%	87%	.	.	-
PG&E	9/20/05	QC 8-Day	311	283	276	270	.	.	92%	86%	76%	76%	.	.	154%	137%	126%	123%	.	.	-
PG&E	9/20/05	10-Day Adj	219	205	200	197	.	.	89%	82%	69%	70%	.	.	108%	99%	91%	90%	.	.	-
PG&E	9/20/05	10-Day	318	294	287	281	.	.	92%	87%	76%	77%	.	.	157%	143%	131%	128%	.	.	-
PG&E	9/21/05	DRP 8-Day Adj	171	219	211	206	.	.	68%	82%	74%	74%	.	.	85%	107%	99%	96%	.	.	209.3
PG&E	9/21/05	QC 8-Day Adj	138	187	184	180	.	.	64%	80%	71%	71%	.	.	69%	91%	86%	84%	.	.	-
PG&E	9/21/05	QC 8-Day	234	272	266	260	.	.	75%	85%	78%	78%	.	.	117%	133%	124%	121%	.	.	-
PG&E	9/21/05	10-Day Adj	143	194	191	187	.	.	64%	80%	72%	72%	.	.	71%	95%	89%	87%	.	.	-
PG&E	9/21/05	10-Day	241	283	278	271	.	.	75%	86%	79%	79%	.	.	121%	138%	129%	126%	.	.	-
PG&E	9/22/05	DRP 8-Day Adj	159	236	224	219	.	.	58%	86%	77%	76%	.	.	79%	115%	104%	102%	.	.	209.0
PG&E	9/22/05	QC 8-Day Adj	124	195	191	186	.	.	52%	83%	74%	73%	.	.	61%	95%	89%	87%	.	.	-
PG&E	9/22/05	QC 8-Day	220	280	273	266	.	.	66%	88%	80%	80%	.	.	109%	137%	127%	124%	.	.	-
PG&E	9/22/05	10-Day Adj	128	202	198	193	.	.	53%	84%	74%	74%	.	.	63%	99%	92%	90%	.	.	-
PG&E	9/22/05	10-Day	227	291	284	277	.	.	66%	88%	81%	80%	.	.	112%	142%	132%	129%	.	.	-
PG&E	9/28/05	DRP 8-Day Adj	2	8	206	204	13	6	8%	17%	71%	71%	14%	12%	78%	134%	94%	93%	67%	93%	78.5
PG&E	9/28/05	QC 8-Day Adj	2	9	261	257	15	7	9%	19%	75%	75%	16%	14%	88%	150%	119%	117%	78%	108%	-
PG&E	9/28/05	QC 8-Day	2	8	264	260	12	6	10%	16%	76%	76%	14%	12%	99%	128%	120%	119%	66%	89%	-
PG&E	9/28/05	10-Day Adj	2	9	267	263	14	7	9%	18%	76%	76%	16%	14%	86%	149%	122%	120%	77%	109%	-
PG&E	9/28/05	10-Day	2	8	274	269	12	6	10%	16%	76%	76%	14%	12%	98%	128%	125%	123%	66%	90%	-
PG&E	9/29/05	DRP 8-Day Adj	.	205	206	203	5	0	.	82%	70%	70%	7%	4%	.	99%	94%	93%	36%	22%	163.5
PG&E	9/29/05	QC 8-Day Adj	.	266	260	255	6	0	.	85%	75%	75%	9%	4%	.	129%	119%	117%	45%	25%	-
PG&E	9/29/05	QC 8-Day	.	270	262	257	5	0	.	85%	75%	75%	8%	4%	.	131%	120%	118%	42%	25%	-
PG&E	9/29/05	10-Day Adj	.	271	266	261	6	0	.	86%	75%	75%	9%	5%	.	132%	121%	119%	45%	26%	-
PG&E	9/29/05	10-Day	.	280	272	267	5	0	.	86%	76%	76%	8%	5%	.	136%	125%	122%	42%	26%	-
PG&E	**Average**	**DRP 8-Day Adj**	**139**	**221**	**226**	**223**	**181**	**3**	**49%**	**60%**	**55%**	**56%**	**50%**	**12%**	**86%**	**115%**	**107%**	**106%**	**115%**	**92%**	**195.7**
PG&E	**Average**	**QC 8-Day Adj**	**138**	**242**	**242**	**238**	**197**	**3**	**48%**	**62%**	**57%**	**58%**	**52%**	**14%**	**85%**	**126%**	**115%**	**114%**	**126%**	**106%**	
PG&E	**Average**	**QC 8-Day**	**172**	**241**	**232**	**228**	**161**	**3**	**54%**	**62%**	**56%**	**57%**	**47%**	**12%**	**106%**	**125%**	**110%**	**109%**	**103%**	**87%**	
PG&E	**Average**	**10-Day Adj**	**143**	**249**	**246**	**242**	**199**	**3**	**49%**	**63%**	**57%**	**58%**	**53%**	**14%**	**88%**	**129%**	**117%**	**115%**	**127%**	**106%**	
PG&E	**Average**	**10-Day**	**179**	**249**	**236**	**232**	**162**	**3**	**55%**	**63%**	**56%**	**57%**	**48%**	**12%**	**110%**	**129%**	**112%**	**111%**	**103%**	**88%**	

Exhibit D6-2
Hourly Impact Estimates for SCE DRP Participants –Events 1-10

Utility	Event	Baseline	Hourly DRP Impacts (MW)								Percent Reduction								Nomination Realization Rate								Utility
			11-12	12-1	1-2	2-3	3-4	4-5	5-6	6-7	11-12	12-1	1-2	2-3	3-4	4-5	5-6	6-7	11-12	12-1	1-2	2-3	3-4	4-5	5-6	6-7	Reported
SCE	6/21/05	DRP 8-Day Adj	.	.	.	1.6	2.9	3.0	.	.	.	.	.	6%	6%	6%	.	.	.	.	.	30%	29%	30%	.	.	10.1
SCE	6/21/05	QC 8-Day Adj	.	.	.	1.4	2.8	2.9	.	.	.	.	.	5%	6%	6%	.	.	.	.	.	27%	28%	29%	.	.	
SCE	6/21/05	QC 8-Day	.	.	.	1.7	2.9	3.0	.	.	.	.	.	6%	6%	6%	.	.	.	.	.	32%	29%	30%	.	.	
SCE	6/21/05	10-Day Adj	.	.	.	1.4	2.8	2.9	.	.	.	.	.	5%	6%	6%	.	.	.	.	.	27%	28%	29%	.	.	
SCE	6/21/05	10-Day	.	.	.	1.7	2.9	3.0	.	.	.	.	.	6%	6%	6%	.	.	.	.	.	33%	29%	30%	.	.	
SCE	6/22/05	DRP 8-Day Adj	.	.	.	7.2	7.7	7.7	.	.	.	.	.	14%	15%	16%	.	.	.	.	.	99%	77%	77%	.	.	10.1
SCE	6/22/05	QC 8-Day Adj	.	.	.	7.1	7.5	7.6	.	.	.	.	.	14%	15%	15%	.	.	.	.	.	97%	75%	76%	.	.	
SCE	6/22/05	QC 8-Day	.	.	.	7.1	7.6	7.6	.	.	.	.	.	14%	15%	15%	.	.	.	.	.	98%	76%	76%	.	.	
SCE	6/22/05	10-Day Adj	.	.	.	7.1	7.5	7.5	.	.	.	.	.	14%	15%	15%	.	.	.	.	.	98%	75%	75%	.	.	
SCE	6/22/05	10-Day	.	.	.	7.2	7.6	7.7	.	.	.	.	.	14%	15%	16%	.	.	.	.	.	100%	76%	76%	.	.	
SCE	6/23/05	DRP 8-Day Adj	.	.	2.1	8.3	8.6	8.8	3.3	.	.	.	8%	17%	17%	18%	12%	.	.	.	41%	114%	86%	87%	44%	.	10.1
SCE	6/23/05	QC 8-Day Adj	.	.	2.0	8.1	8.5	8.7	3.1	.	.	.	8%	16%	17%	18%	12%	.	.	.	39%	112%	85%	87%	43%	.	
SCE	6/23/05	QC 8-Day	.	.	2.3	8.2	8.6	8.7	3.4	.	.	.	9%	16%	17%	18%	13%	.	.	.	44%	113%	85%	87%	46%	.	
SCE	6/23/05	10-Day Adj	.	.	2.0	8.2	8.5	8.7	3.1	.	.	.	8%	16%	17%	18%	12%	.	.	.	39%	113%	85%	86%	42%	.	
SCE	6/23/05	10-Day	.	.	2.4	8.3	8.6	8.8	3.4	.	.	.	9%	17%	17%	18%	13%	.	.	.	45%	114%	86%	88%	47%	.	
SCE	7/13/05	DRP 8-Day Adj	.	.	.	10.7	11.4	15.5	.	.	.	.	.	11%	12%	17%	.	.	.	.	.	49%	33%	46%	.	.	33.9
SCE	7/13/05	QC 8-Day Adj	.	.	.	10.3	11.0	14.8	.	.	.	.	.	11%	12%	17%	.	.	.	.	.	47%	33%	44%	.	.	
SCE	7/13/05	QC 8-Day	.	.	.	7.6	8.3	12.1	.	.	.	.	.	9%	9%	14%	.	.	.	.	.	34%	25%	36%	.	.	
SCE	7/13/05	10-Day Adj	.	.	.	10.4	11.1	14.8	.	.	.	.	.	11%	12%	17%	.	.	.	.	.	47%	33%	44%	.	.	
SCE	7/13/05	10-Day	.	.	.	7.1	7.8	11.5	.	.	.	.	.	8%	9%	13%	.	.	.	.	.	32%	23%	34%	.	.	
SCE	7/14/05	DRP 8-Day Adj	.	-6.8	-4.7	-3.2	4.5	4.2	-3.1	-7.3	.	-20%	-8%	-6%	5%	5%	-3%	-23%	.	-62%	-31%	-21%	13%	12%	-9%	-67%	35.4
SCE	7/14/05	QC 8-Day Adj	.	-7.9	-5.3	-3.9	4.2	4.0	-3.3	-8.2	.	-23%	-9%	-7%	5%	4%	-4%	-27%	.	-72%	-34%	-26%	12%	11%	-9%	-75%	
SCE	7/14/05	QC 8-Day	.	-6.6	-4.7	-3.4	1.2	1.0	-6.2	-7.1	.	-19%	-8%	-6%	1%	1%	-7%	-22%	.	-60%	-31%	-22%	3%	3%	-18%	-65%	
SCE	7/14/05	10-Day Adj	.	-7.7	-5.5	-3.8	4.2	4.0	-3.5	-8.2	.	-23%	-10%	-7%	5%	4%	-4%	-26%	.	-70%	-36%	-25%	12%	11%	-10%	-75%	
SCE	7/14/05	10-Day	.	-6.6	-5.2	-3.5	0.7	0.4	-7.0	-7.3	.	-19%	-9%	-6%	1%	0%	-8%	-23%	.	-60%	-34%	-23%	2%	1%	-20%	-66%	
SCE	7/19/05	DRP 8-Day Adj	.	.	.	9.8	10.8	11.0	.	.	.	.	.	15%	16%	17%	.	.	.	.	.	68%	54%	55%	.	.	19.9
SCE	7/19/05	QC 8-Day Adj	.	.	.	13.7	14.6	14.7	.	.	.	.	.	20%	21%	22%	.	.	.	.	.	96%	73%	74%	.	.	
SCE	7/19/05	QC 8-Day	.	.	.	15.9	16.8	17.1	.	.	.	.	.	23%	24%	25%	.	.	.	.	.	111%	84%	86%	.	.	
SCE	7/19/05	10-Day Adj	.	.	.	13.4	14.3	14.5	.	.	.	.	.	20%	21%	22%	.	.	.	.	.	94%	72%	73%	.	.	
SCE	7/19/05	10-Day	.	.	.	15.0	15.8	16.1	.	.	.	.	.	22%	23%	24%	.	.	.	.	.	105%	79%	81%	.	.	
SCE	7/20/05	DRP 8-Day Adj	.	.	.	9.6	10.4	10.5	.	.	.	.	.	15%	16%	17%	.	.	.	.	.	75%	56%	57%	.	.	18.4
SCE	7/20/05	QC 8-Day Adj	.	.	.	13.7	14.4	14.8	.	.	.	.	.	21%	22%	22%	.	.	.	.	.	107%	78%	80%	.	.	
SCE	7/20/05	QC 8-Day	.	.	.	15.8	16.5	17.0	.	.	.	.	.	23%	24%	25%	.	.	.	.	.	123%	90%	92%	.	.	
SCE	7/20/05	10-Day Adj	.	.	.	13.4	14.1	14.5	.	.	.	.	.	20%	21%	22%	.	.	.	.	.	105%	77%	79%	.	.	
SCE	7/20/05	10-Day	.	.	.	14.9	15.6	16.1	.	.	.	.	.	22%	23%	24%	.	.	.	.	.	116%	84%	87%	.	.	
SCE	7/21/05	DRP 8-Day Adj	.	.	.	9.3	9.7	9.9	.	.	.	.	.	14%	15%	15%	.	.	.	.	.	65%	49%	50%	.	.	19.9
SCE	7/21/05	QC 8-Day Adj	.	.	.	13.7	13.6	14.0	.	.	.	.	.	20%	20%	21%	.	.	.	.	.	96%	68%	70%	.	.	
SCE	7/21/05	QC 8-Day	.	.	.	15.9	15.8	16.4	.	.	.	.	.	23%	23%	24%	.	.	.	.	.	111%	80%	82%	.	.	
SCE	7/21/05	10-Day Adj	.	.	.	13.4	13.3	13.8	.	.	.	.	.	20%	20%	21%	.	.	.	.	.	94%	67%	69%	.	.	
SCE	7/21/05	10-Day	.	.	.	15.0	14.8	15.4	.	.	.	.	.	22%	21%	22%	.	.	.	.	.	105%	75%	77%	.	.	
SCE	7/22/05	DRP 8-Day Adj	.	.	.	.	.	6.8	.	.	.	.	.	.	.	14%	.	.	.	.	.	.	.	41%	.	.	16.6
SCE	7/22/05	QC 8-Day Adj	.	.	.	.	.	11.0	.	.	.	.	.	.	.	22%	.	.	.	.	.	.	.	67%	.	.	
SCE	7/22/05	QC 8-Day	.	.	.	.	.	14.4	.	.	.	.	.	.	.	27%	.	.	.	.	.	.	.	87%	.	.	
SCE	7/22/05	10-Day Adj	.	.	.	.	.	10.8	.	.	.	.	.	.	.	22%	.	.	.	.	.	.	.	65%	.	.	
SCE	7/22/05	10-Day	.	.	.	.	.	13.5	.	.	.	.	.	.	.	26%	.	.	.	.	.	.	.	82%	.	.	
SCE	7/29/05	DRP 8-Day Adj	.	.	.	12.5	12.7	12.8	.	.	.	.	.	24%	24%	25%	.	.	.	.	.	123%	84%	85%	.	.	15.1
SCE	7/29/05	QC 8-Day Adj	.	.	.	12.5	12.7	12.8	.	.	.	.	.	24%	24%	25%	.	.	.	.	.	123%	84%	85%	.	.	
SCE	7/29/05	QC 8-Day	.	.	.	14.2	14.3	14.5	.	.	.	.	.	26%	27%	27%	.	.	.	.	.	139%	94%	96%	.	.	
SCE	7/29/05	10-Day Adj	.	.	.	12.6	12.7	12.7	.	.	.	.	.	24%	24%	25%	.	.	.	.	.	124%	84%	84%	.	.	
SCE	7/29/05	10-Day	.	.	.	13.9	13.9	14.0	.	.	.	.	.	26%	26%	26%	.	.	.	.	.	136%	92%	92%	.	.	

Exhibit D6-2 (con't)
Hourly Impact Estimates for SCE DRP Participants –Events 11-19 and Summer Average

Utility	Event	Baseline	Hourly DRP Impacts (MW)								Percent Reduction								Nomination Realization Rate								Utility Reported
			11-12	12-1	1-2	2-3	3-4	4-5	5-6	6-7	11-12	12-1	1-2	2-3	3-4	4-5	5-6	6-7	11-12	12-1	1-2	2-3	3-4	4-5	5-6	6-7	
SCE	8/17/05	DRP 8-Day Adj	.	.	.	-2.3	2.5	2.5	0.5	.	.	.	.	-3%	3%	3%	1%	.	.	.	.	-9%	8%	8%	2%	.	31.7
SCE	8/17/05	QC 8-Day Adj	.	.	.	-2.4	2.4	2.4	0.4	.	.	.	.	-3%	3%	3%	1%	.	.	.	.	-9%	8%	8%	2%	.	
SCE	8/17/05	QC 8-Day	.	.	.	3.5	8.1	8.1	5.3	.	.	.	.	4%	9%	9%	9%	.	.	.	.	13%	26%	25%	21%	.	
SCE	8/17/05	10-Day Adj	.	.	.	-2.5	2.5	2.0	0.4	.	.	.	.	-3%	3%	2%	1%	.	.	.	.	-9%	8%	6%	1%	.	
SCE	8/17/05	10-Day	.	.	.	3.4	8.3	7.8	5.2	.	.	.	.	4%	9%	9%	9%	.	.	.	.	13%	26%	24%	21%	.	
SCE	8/23/05	DRP 8-Day Adj	.	0.0	4.9	8.5	8.2	8.2	4.8	0.2	.	-1%	17%	16%	16%	16%	17%	4%	.	-3%	87%	85%	55%	55%	56%	16%	14.8
SCE	8/23/05	QC 8-Day Adj	.	0.0	4.9	8.5	8.2	8.2	4.8	0.2	.	0%	17%	16%	16%	16%	17%	5%	.	-2%	88%	85%	55%	56%	56%	21%	
SCE	8/23/05	QC 8-Day	.	0.0	5.5	9.0	8.7	8.9	5.4	0.2	.	0%	19%	17%	17%	17%	19%	6%	.	1%	99%	90%	59%	60%	63%	25%	
SCE	8/23/05	10-Day Adj	.	0.0	4.9	8.4	8.1	8.1	4.8	0.2	.	0%	17%	16%	16%	16%	17%	6%	.	-1%	88%	84%	55%	55%	56%	22%	
SCE	8/23/05	10-Day	.	0.0	5.4	8.7	8.5	8.5	5.4	0.2	.	0%	19%	17%	16%	17%	19%	6%	.	1%	98%	87%	57%	58%	63%	25%	
SCE	8/25/05	DRP 8-Day Adj	.	.	.	.	11.0	26.7	.	.	.	.	.	.	12%	29%	.	.	.	.	.	.	36%	87%	.	.	30.8
SCE	8/25/05	QC 8-Day Adj	.	.	.	.	10.2	26.0	.	.	.	.	.	.	11%	28%	.	.	.	.	.	.	33%	85%	.	.	
SCE	8/25/05	QC 8-Day	.	.	.	.	1.8	17.3	.	.	.	.	.	.	2%	21%	.	.	.	.	.	.	6%	56%	.	.	
SCE	8/25/05	10-Day Adj	.	.	.	.	9.6	25.0	.	.	.	.	.	.	10%	27%	.	.	.	.	.	.	31%	81%	.	.	
SCE	8/25/05	10-Day	.	.	.	.	1.1	16.4	.	.	.	.	.	.	1%	20%	.	.	.	.	.	.	4%	53%	.	.	
SCE	8/26/05	DRP 8-Day Adj	.	.	.	17.2	15.3	14.3	.	.	.	.	.	18%	16%	15%	.	.	.	.	.	66%	50%	46%	.	.	30.8
SCE	8/26/05	QC 8-Day Adj	.	.	.	16.5	14.5	13.0	.	.	.	.	.	17%	16%	14%	.	.	.	.	.	63%	47%	42%	.	.	
SCE	8/26/05	QC 8-Day	.	.	.	7.7	6.1	4.3	.	.	.	.	.	9%	7%	5%	.	.	.	.	.	30%	20%	14%	.	.	
SCE	8/26/05	10-Day Adj	.	.	.	15.5	13.9	12.0	.	.	.	.	.	16%	15%	13%	.	.	.	.	.	59%	45%	39%	.	.	
SCE	8/26/05	10-Day	.	.	.	6.6	5.5	3.3	.	.	.	.	.	8%	7%	4%	.	.	.	.	.	25%	18%	11%	.	.	
SCE	9/1/05	DRP 8-Day Adj	.	0.4	1.6	4.8	4.6	2.7	1.9	0.4	.	95%	19%	14%	14%	9%	24%	95%	.	280%	42%	65%	40%	24%	35%	282%	11.4
SCE	9/1/05	QC 8-Day Adj	.	0.4	1.6	4.7	4.4	2.4	1.8	0.4	.	95%	19%	14%	13%	8%	23%	95%	.	281%	42%	62%	38%	21%	33%	282%	
SCE	9/1/05	QC 8-Day	.	0.4	1.4	3.5	3.3	1.4	1.7	0.4	.	95%	17%	11%	10%	5%	21%	95%	.	281%	37%	47%	28%	13%	30%	282%	
SCE	9/1/05	10-Day Adj	.	0.4	1.6	4.6	4.3	2.3	1.8	0.4	.	95%	19%	14%	13%	8%	23%	95%	.	283%	42%	61%	38%	20%	33%	282%	
SCE	9/1/05	10-Day	.	0.4	1.4	3.4	3.1	1.3	1.7	0.4	.	95%	17%	11%	10%	4%	22%	95%	.	283%	37%	45%	28%	11%	30%	282%	
SCE	9/6/05	DRP 8-Day Adj	0.0	0.0	-1.1	-0.8	-1.2	-1.5	-0.6	0.4	-3%	0%	-20%	-3%	-4%	-6%	-11%	95%	-9%	-1%	-43%	-13%	-13%	-16%	-17%	286%	9.6
SCE	9/6/05	QC 8-Day Adj	0.0	0.0	-1.1	-0.3	-0.7	-1.1	-0.7	0.4	-7%	-3%	-20%	-1%	-2%	-4%	-12%	95%	-19%	-9%	-43%	-4%	-7%	-11%	-18%	279%	
SCE	9/6/05	QC 8-Day	0.0	0.0	1.0	2.6	2.2	1.7	1.5	0.4	-7%	-3%	13%	8%	7%	6%	19%	95%	-19%	-9%	38%	41%	23%	17%	40%	279%	
SCE	9/6/05	10-Day Adj	0.0	0.0	-1.1	-0.3	-0.7	-1.2	-0.7	0.4	-7%	-2%	-20%	-1%	-2%	-4%	-12%	95%	-20%	-7%	-43%	-5%	-7%	-12%	-18%	280%	
SCE	9/6/05	10-Day	0.0	0.0	0.8	2.3	1.9	1.3	1.3	0.4	-7%	-2%	10%	7%	6%	4%	17%	95%	-20%	-7%	30%	36%	20%	14%	35%	280%	
SCE	9/21/05	DRP 8-Day Adj	.	0.3	0.6	0.6	2.5	2.5	2.6	0.4	.	95%	11%	11%	27%	27%	28%	95%	.	268%	63%	62%	45%	46%	47%	270%	5.6
SCE	9/21/05	QC 8-Day Adj	.	0.3	0.7	0.7	2.7	2.7	2.8	0.4	.	95%	12%	11%	28%	29%	30%	95%	.	268%	67%	66%	48%	48%	50%	270%	
SCE	9/21/05	QC 8-Day	.	0.3	0.4	0.4	2.4	2.4	2.5	0.4	.	95%	8%	8%	26%	26%	27%	95%	.	268%	43%	42%	43%	43%	44%	270%	
SCE	9/21/05	10-Day Adj	.	0.3	0.7	0.7	2.7	2.7	2.7	0.4	.	95%	12%	11%	28%	28%	29%	95%	.	269%	67%	66%	48%	48%	49%	272%	
SCE	9/21/05	10-Day	.	0.3	0.5	0.4	2.4	2.4	2.5	0.4	.	95%	8%	8%	26%	26%	27%	95%	.	269%	44%	43%	43%	43%	44%	272%	
SCE	9/22/05	DRP 8-Day Adj	.	.	0.2	2.2	2.2	2.2	0.3	.	.	.	5%	27%	27%	28%	5%	.	.	.	27%	79%	47%	49%	17%	.	4.6
SCE	9/22/05	QC 8-Day Adj	.	.	0.3	2.3	2.3	2.3	0.3	.	.	.	5%	29%	28%	29%	5%	.	.	.	32%	85%	50%	51%	20%	.	
SCE	9/22/05	QC 8-Day	.	.	0.0	2.1	2.1	2.1	0.1	.	.	.	1%	27%	26%	27%	1%	.	.	.	5%	76%	45%	45%	4%	.	
SCE	9/22/05	10-Day Adj	.	.	0.3	2.3	2.3	2.3	0.3	.	.	.	5%	28%	28%	28%	5%	.	.	.	32%	83%	49%	49%	20%	.	
SCE	9/22/05	10-Day	.	.	0.0	2.1	2.0	2.1	0.1	.	.	.	1%	27%	26%	26%	1%	.	.	.	5%	76%	45%	45%	4%	.	
SCE	9/30/05	DRP 8-Day Adj	.	.	.	3.8	4.6	4.8	1.9	.	.	.	.	13%	16%	16%	22%	.	.	.	.	70%	57%	59%	53%	.	8.1
SCE	9/30/05	QC 8-Day Adj	.	.	.	4.4	5.2	5.4	2.0	.	.	.	.	14%	17%	18%	23%	.	.	.	.	79%	65%	66%	57%	.	
SCE	9/30/05	QC 8-Day	.	.	.	1.2	2.1	2.3	1.0	.	.	.	.	4%	8%	9%	13%	.	.	.	.	22%	26%	29%	28%	.	
SCE	9/30/05	10-Day Adj	.	.	.	4.3	5.2	5.3	2.0	.	.	.	.	14%	17%	18%	23%	.	.	.	.	79%	64%	65%	57%	.	
SCE	9/30/05	10-Day	.	.	.	1.3	2.1	2.4	1.0	.	.	.	.	5%	8%	9%	13%	.	.	.	.	23%	26%	29%	28%	.	
SCE	**Average**	**DRP 8-Day Adj**	**0.0**	**-1.2**	**0.5**	**5.9**	**7.1**	**8.0**	**1.3**	**-1.2**	**-3%**	**-15%**	**3%**	**12%**	**13%**	**15%**	**5%**	**-16%**	**-9%**	**-49%**	**10%**	**51%**	**40%**	**45%**	**12%**	**-48%**	**17.7**
SCE	**Average**	**QC 8-Day Adj**	**0.0**	**-1.4**	**0.4**	**6.5**	**7.7**	**8.8**	**1.3**	**-1.4**	**-7%**	**-19%**	**2%**	**13%**	**14%**	**16%**	**5%**	**-19%**	**-19%**	**-57%**	**9%**	**57%**	**43%**	**49%**	**12%**	**-55%**	
SCE	**Average**	**QC 8-Day**	**0.0**	**-1.2**	**0.8**	**6.7**	**7.2**	**8.4**	**1.6**	**-1.2**	**-7%**	**-15%**	**4%**	**13%**	**13%**	**15%**	**6%**	**-15%**	**-19%**	**-47%**	**17%**	**58%**	**40%**	**48%**	**15%**	**-46%**	
SCE	**Average**	**10-Day Adj**	**0.0**	**-1.4**	**0.4**	**6.4**	**7.6**	**8.6**	**1.2**	**-1.4**	**-7%**	**-18%**	**2%**	**13%**	**13%**	**16%**	**5%**	**-19%**	**-20%**	**-55%**	**8%**	**56%**	**43%**	**48%**	**12%**	**-55%**	
SCE	**Average**	**10-Day**	**0.0**	**-1.2**	**0.7**	**6.3**	**6.8**	**8.0**	**1.5**	**-1.2**	**-7%**	**-15%**	**4%**	**12%**	**12%**	**15%**	**6%**	**-16%**	**-20%**	**-47%**	**15%**	**55%**	**38%**	**45%**	**14%**	**-47%**	

Exhibit D6-3
Hourly Impact Estimates for SDG&E DRP Participants –Events 1-7 and Summer Average

Utility	Event	Baseline	Hourly DRP Impacts (MW)					Percent Reduction					Nomination Realization Rate					Utility
			1-2	2-3	3-4	4-5	5-6	1-2	2-3	3-4	4-5	5-6	1-2	2-3	3-4	4-5	5-6	Reported
SDG&E	6/30/05	DRP 8-Day Adj	.	3.7	.	.	.	.	29%	.	.	.	.	174%	.	.	.	n/a
SDG&E	6/30/05	QC 8-Day Adj	.	3.6	.	.	.	.	29%	.	.	.	.	173%	.	.	.	
SDG&E	6/30/05	QC 8-Day	.	3.2	.	.	.	.	26%	.	.	.	.	151%	.	.	.	
SDG&E	6/30/05	10-Day Adj	.	3.4	.	.	.	.	28%	.	.	.	.	164%	.	.	.	
SDG&E	6/30/05	10-Day	.	3.0	.	.	.	.	25%	.	.	.	.	145%	.	.	.	
SDG&E	7/14/05	DRP 8-Day Adj	.	1.4	2.4	.	.	.	10%	17%	.	.	.	69%	84%	.	.	1.9
SDG&E	7/14/05	QC 8-Day Adj	.	1.1	2.2	.	.	.	8%	16%	.	.	.	56%	76%	.	.	
SDG&E	7/14/05	QC 8-Day	.	0.0	1.1	.	.	.	0%	9%	.	.	.	-2%	37%	.	.	
SDG&E	7/14/05	10-Day Adj	.	0.9	1.9	.	.	.	6%	14%	.	.	.	44%	67%	.	.	
SDG&E	7/14/05	10-Day	.	0.0	1.1	.	.	.	0%	9%	.	.	.	1%	38%	.	.	
SDG&E	7/20/05	DRP 8-Day Adj	.	.	1.3	1.2	.	.	.	8%	9%	.	.	.	44%	41%	.	1.2
SDG&E	7/20/05	QC 8-Day Adj	.	.	1.1	1.1	.	.	.	7%	8%	.	.	.	38%	37%	.	
SDG&E	7/20/05	QC 8-Day	.	.	-0.3	-0.1	.	.	.	-2%	-1%	.	.	.	-10%	-4%	.	
SDG&E	7/20/05	10-Day Adj	.	.	0.9	0.9	.	.	.	6%	7%	.	.	.	32%	33%	.	
SDG&E	7/20/05	10-Day	.	.	-0.2	0.0	.	.	.	-1%	0%	.	.	.	-7%	0%	.	
SDG&E	7/21/05	DRP 8-Day Adj	.	1.8	1.8	2.7	.	.	11%	12%	19%	.	.	87%	62%	93%	.	2.1
SDG&E	7/21/05	QC 8-Day Adj	.	1.4	1.5	2.4	.	.	9%	10%	17%	.	.	67%	51%	82%	.	
SDG&E	7/21/05	QC 8-Day	.	-0.1	0.1	1.2	.	.	-1%	1%	10%	.	.	-7%	2%	41%	.	
SDG&E	7/21/05	10-Day Adj	.	1.1	1.3	2.2	.	.	7%	9%	17%	.	.	55%	44%	78%	.	
SDG&E	7/21/05	10-Day	.	-0.1	0.2	1.3	.	.	0%	1%	10%	.	.	-3%	6%	45%	.	
SDG&E	7/22/05	DRP 8-Day Adj	0.4	0.8	1.0	1.9	.	2%	5%	6%	14%	.	18%	41%	33%	67%	.	1.0
SDG&E	7/22/05	QC 8-Day Adj	0.0	0.4	0.6	1.7	.	0%	3%	4%	12%	.	-1%	21%	22%	58%	.	
SDG&E	7/22/05	QC 8-Day	-1.5	-1.1	-0.8	0.5	.	-11%	-8%	-6%	4%	.	-75%	-53%	-26%	17%	.	
SDG&E	7/22/05	10-Day Adj	-0.3	0.2	0.5	1.5	.	-2%	1%	3%	11%	.	-13%	9%	16%	54%	.	
SDG&E	7/22/05	10-Day	-1.4	-1.0	-0.6	0.6	.	-10%	-7%	-5%	5%	.	-71%	-49%	-23%	21%	.	
SDG&E	8/26/05	DRP 8-Day Adj	1.6	2.1	2.2	2.3	3.6	10%	14%	14%	17%	30%	65%	86%	60%	65%	99%	n/a
SDG&E	8/26/05	QC 8-Day Adj	1.6	2.1	2.2	2.4	3.6	11%	14%	15%	17%	30%	67%	87%	61%	66%	101%	
SDG&E	8/26/05	QC 8-Day	0.1	0.6	0.7	1.1	2.6	1%	4%	5%	9%	23%	5%	24%	20%	30%	72%	
SDG&E	8/26/05	10-Day Adj	1.6	2.1	2.1	2.5	3.9	11%	13%	14%	18%	31%	66%	85%	60%	68%	109%	
SDG&E	8/26/05	10-Day	0.1	0.6	0.7	1.2	2.9	1%	4%	5%	9%	25%	6%	24%	20%	33%	80%	
SDG&E	8/29/05	DRP 8-Day Adj	2.4	2.4	2.2	2.0	1.6	16%	16%	15%	14%	14%	97%	99%	61%	55%	46%	2.1
SDG&E	8/29/05	QC 8-Day Adj	2.4	2.4	2.2	2.0	1.7	16%	16%	15%	14%	14%	99%	99%	61%	55%	46%	
SDG&E	8/29/05	QC 8-Day	0.9	0.9	0.7	0.7	0.6	7%	6%	5%	6%	6%	37%	36%	20%	20%	17%	
SDG&E	8/29/05	10-Day Adj	2.4	2.4	2.1	2.1	1.9	16%	15%	14%	15%	16%	98%	96%	59%	58%	54%	
SDG&E	8/29/05	10-Day	0.9	0.9	0.7	0.8	0.9	7%	6%	5%	6%	8%	38%	35%	20%	23%	25%	
SDG&E	**Average**	**DRP 8-Day Adj**	**1.5**	**2.0**	**1.8**	**2.0**	**2.6**	**9%**	**14%**	**12%**	**15%**	**22%**	**63%**	**93%**	**58%**	**64%**	**73%**	**1.7**
SDG&E	**Average**	**QC 8-Day Adj**	**1.4**	**1.9**	**1.6**	**1.9**	**2.6**	**9%**	**13%**	**11%**	**14%**	**22%**	**59%**	**85%**	**52%**	**60%**	**73%**	
SDG&E	**Average**	**QC 8-Day**	**-0.2**	**0.6**	**0.3**	**0.7**	**1.6**	**-1%**	**4%**	**2%**	**5%**	**15%**	**-7%**	**26%**	**8%**	**21%**	**45%**	
SDG&E	**Average**	**10-Day Adj**	**1.3**	**1.7**	**1.5**	**1.8**	**2.9**	**8%**	**12%**	**10%**	**14%**	**24%**	**54%**	**77%**	**47%**	**58%**	**81%**	
SDG&E	**Average**	**10-Day**	**-0.1**	**0.6**	**0.3**	**0.8**	**1.9**	**-1%**	**4%**	**2%**	**6%**	**17%**	**-5%**	**27%**	**10%**	**25%**	**52%**	

D7. DRP Daily Impact Estimates

D7. DRP DAILY IMPACT ESTIMATES

The DRP Daily Impact Tables included in Appendix D7 contain the MWh impact estimates across all event hours for the summer of 2005 DRP events for each of the three utilities. The daily impact estimates are calculated as the sum of the individual DRP participant impact estimates across all DRP participants who nominated load for a given event. These were calculated as sums rather than daily averages since the event length for each of the DRP product types triggered (1-3 hour, 1-5 hour or 1-8 hour) changed for each event. These tables provide the total estimated MWh impact by utility across all products triggered. A complete listing of the products type called and the event length for all summer events across the three utilities is included in Chapter 6, Exhibit 6-3.

The Exhibits in this Appendix include the following:

- D7-1 Daily DRP MWh Impact Estimates for PG&E DRP Participants – Summer 2005 Events
- D7-2 Daily DRP MWh Impact Estimates for PG&E DRP Participants – Summer 2005 Events
- D7-3 Daily DRP MWh Impact Estimates for PG&E DRP Participants – Summer 2005 Events

Exhibit D7-1 (con't)
PG&E Daily DRP MWh Impact Estimates based on 10-Day Adjusted Baseline – Events 9-16

Utility	Program	Event	Baseline	n	Daily MWh Estimates Base Load	Daily MWh Estimates Impacts	% Reduction
PGE	DRP	8/8/05	DRP 8-Day Adj	41	1,311	**1,041**	79.5%
PGE	DRP	8/8/05	QC 8-Day Adj	41	1,323	**1,054**	79.7%
PGE	DRP	8/8/05	QC 8-Day	41	1,392	**1,123**	80.7%
PGE	DRP	8/8/05	10-Day Adj	41	1,376	**1,107**	80.4%
PGE	DRP	8/8/05	10-Day	41	1,439	**1,170**	81.3%
PGE	DRP	8/10/05	DRP 8-Day Adj	42	1,254	**1,016**	81.0%
PGE	DRP	8/10/05	QC 8-Day Adj	42	1,076	**838**	77.9%
PGE	DRP	8/10/05	QC 8-Day	42	1,031	**793**	77.0%
PGE	DRP	8/10/05	10-Day Adj	42	1,095	**857**	78.3%
PGE	DRP	8/10/05	10-Day	42	1,046	**809**	77.3%
PGE	DRP	8/11/05	DRP 8-Day Adj	42	1,223	**1,063**	86.9%
PGE	DRP	8/11/05	QC 8-Day Adj	42	1,076	**915**	85.1%
PGE	DRP	8/11/05	QC 8-Day	42	1,031	**870**	84.4%
PGE	DRP	8/11/05	10-Day Adj	42	1,095	**934**	85.3%
PGE	DRP	8/11/05	10-Day	42	1,046	**886**	84.6%
PGE	DRP	8/12/05	DRP 8-Day Adj	33	1,242	**1,087**	87.6%
PGE	DRP	8/12/05	QC 8-Day Adj	33	1,099	**945**	85.9%
PGE	DRP	8/12/05	QC 8-Day	33	1,052	**898**	85.3%
PGE	DRP	8/12/05	10-Day Adj	33	1,112	**957**	86.1%
PGE	DRP	8/12/05	10-Day	33	1,061	**907**	85.4%
PGE	DRP	8/17/05	DRP 8-Day Adj	33	936	**807**	86.3%
PGE	DRP	8/17/05	QC 8-Day Adj	33	992	**863**	87.1%
PGE	DRP	8/17/05	QC 8-Day	33	1,001	**873**	87.2%
PGE	DRP	8/17/05	10-Day Adj	33	1,000	**871**	87.2%
PGE	DRP	8/17/05	10-Day	33	1,012	**884**	87.3%
PGE	DRP	8/18/05	DRP 8-Day Adj	33	915	**790**	86.4%
PGE	DRP	8/18/05	QC 8-Day Adj	33	992	**867**	87.5%
PGE	DRP	8/18/05	QC 8-Day	33	1,001	**877**	87.6%
PGE	DRP	8/18/05	10-Day Adj	33	1,000	**875**	87.6%
PGE	DRP	8/18/05	10-Day	33	1,012	**888**	87.7%
PGE	DRP	8/23/05	DRP 8-Day Adj	59	623	**378**	60.8%
PGE	DRP	8/23/05	QC 8-Day Adj	59	678	**434**	64.0%
PGE	DRP	8/23/05	QC 8-Day	59	1,022	**777**	76.1%
PGE	DRP	8/23/05	10-Day Adj	59	683	**438**	64.2%
PGE	DRP	8/23/05	10-Day	59	1,029	**785**	76.3%
PGE	DRP	8/25/05	DRP 8-Day Adj	67	616	**379**	61.4%
PGE	DRP	8/25/05	QC 8-Day Adj	67	610	**372**	61.1%
PGE	DRP	8/25/05	QC 8-Day	67	744	**507**	68.1%
PGE	DRP	8/25/05	10-Day Adj	67	613	**376**	61.3%
PGE	DRP	8/25/05	10-Day	67	750	**512**	68.3%

Exhibit D7-1 (con't)
PG&E Daily DRP MWh Impact Estimates based on 10-Day Adjusted Baseline – Events 17-24 and Overall Event Average

Utility	Program	Event	Baseline	n	Daily MWh Estimates		%
					Base Load	Impacts	Reduction
PGE	DRP	8/26/05	DRP 8-Day Adj	27	113	**24**	21.2%
PGE	DRP	8/26/05	QC 8-Day Adj	27	113	**24**	21.4%
PGE	DRP	8/26/05	QC 8-Day	27	112	**23**	20.8%
PGE	DRP	8/26/05	10-Day Adj	27	113	**24**	21.4%
PGE	DRP	8/26/05	10-Day	27	112	**23**	20.8%
PGE	DRP	9/6/05	DRP 8-Day Adj	45	830	**650**	78.4%
PGE	DRP	9/6/05	QC 8-Day Adj	45	787	**607**	77.2%
PGE	DRP	9/6/05	QC 8-Day	45	793	**613**	77.4%
PGE	DRP	9/6/05	10-Day Adj	45	776	**597**	76.9%
PGE	DRP	9/6/05	10-Day	45	783	**603**	77.1%
PGE	DRP	9/19/05	DRP 8-Day Adj	59	873	**652**	74.6%
PGE	DRP	9/19/05	QC 8-Day Adj	59	801	**579**	72.3%
PGE	DRP	9/19/05	QC 8-Day	59	1,049	**827**	78.9%
PGE	DRP	9/19/05	10-Day Adj	59	821	**600**	73.0%
PGE	DRP	9/19/05	10-Day	59	1,082	**860**	79.5%
PGE	DRP	9/20/05	DRP 8-Day Adj	64	1,160	**915**	78.8%
PGE	DRP	9/20/05	QC 8-Day Adj	64	1,042	**796**	76.4%
PGE	DRP	9/20/05	QC 8-Day	64	1,386	**1,140**	82.3%
PGE	DRP	9/20/05	10-Day Adj	64	1,067	**822**	77.0%
PGE	DRP	9/20/05	10-Day	64	1,427	**1,181**	82.8%
PGE	DRP	9/21/05	DRP 8-Day Adj	43	1,082	**808**	74.6%
PGE	DRP	9/21/05	QC 8-Day Adj	43	963	**689**	71.5%
PGE	DRP	9/21/05	QC 8-Day	43	1,305	**1,031**	79.0%
PGE	DRP	9/21/05	10-Day Adj	43	988	**714**	72.2%
PGE	DRP	9/21/05	10-Day	43	1,346	**1,072**	79.6%
PGE	DRP	9/22/05	DRP 8-Day Adj	46	1,128	**838**	74.3%
PGE	DRP	9/22/05	QC 8-Day Adj	46	985	**696**	70.6%
PGE	DRP	9/22/05	QC 8-Day	46	1,328	**1,038**	78.2%
PGE	DRP	9/22/05	10-Day Adj	46	1,011	**721**	71.3%
PGE	DRP	9/22/05	10-Day	46	1,369	**1,080**	78.8%
PGE	DRP	9/28/05	DRP 8-Day Adj	89	788	**438**	55.6%
PGE	DRP	9/28/05	QC 8-Day Adj	89	901	**551**	61.1%
PGE	DRP	9/28/05	QC 8-Day	89	902	**551**	61.2%
PGE	DRP	9/28/05	10-Day Adj	89	913	**563**	61.6%
PGE	DRP	9/28/05	10-Day	89	921	**571**	62.0%
PGE	DRP	9/29/05	DRP 8-Day Adj	75	896	**618**	68.9%
PGE	DRP	9/29/05	QC 8-Day Adj	75	1,064	**786**	73.8%
PGE	DRP	9/29/05	QC 8-Day	75	1,073	**795**	74.1%
PGE	DRP	9/29/05	10-Day Adj	75	1,082	**803**	74.3%
PGE	DRP	9/29/05	10-Day	75	1,103	**824**	74.8%
PGE	**DRP**	**Average**	**DRP 8-Day Adj**	**57**	**1,322**	**731**	**55.3%**
PGE	**DRP**	**Average**	**QC 8-Day Adj**	**57**	**1,377**	**786**	**57.1%**
PGE	**DRP**	**Average**	**QC 8-Day**	**57**	**1,341**	**750**	**55.9%**
PGE	**DRP**	**Average**	**10-Day Adj**	**57**	**1,391**	**800**	**57.5%**
PGE	**DRP**	**Average**	**10-Day**	**57**	**1,357**	**766**	**56.4%**

Exhibit D7-2
SCE Daily DRP MWh Impact Estimates based on 10-Day Adjusted Baseline– Events 1-7

Utility	Program	Event	Baseline	n	Daily MWh Estimates		%
					Base Load	Impacts	Reduction
SCE	DRP	6/21/05	DRP 8-Day Adj	25	126.3	**7.5**	5.9%
SCE	DRP	6/21/05	QC 8-Day Adj	25	125.9	**7.1**	5.7%
SCE	DRP	6/21/05	QC 8-Day	25	126.3	**7.5**	5.9%
SCE	DRP	6/21/05	10-Day Adj	25	125.9	**7.1**	5.6%
SCE	DRP	6/21/05	10-Day	25	126.4	**7.6**	6.0%
SCE	DRP	6/22/05	DRP 8-Day Adj	30	149.4	**22.6**	15.1%
SCE	DRP	6/22/05	QC 8-Day Adj	30	149.0	**22.2**	14.9%
SCE	DRP	6/22/05	QC 8-Day	30	149.1	**22.4**	15.0%
SCE	DRP	6/22/05	10-Day Adj	30	149.0	**22.2**	14.9%
SCE	DRP	6/22/05	10-Day	30	149.3	**22.5**	15.1%
SCE	DRP	6/23/05	DRP 8-Day Adj	40	202.9	**31.2**	15.4%
SCE	DRP	6/23/05	QC 8-Day Adj	40	202.2	**30.5**	15.1%
SCE	DRP	6/23/05	QC 8-Day	40	203.0	**31.2**	15.4%
SCE	DRP	6/23/05	10-Day Adj	40	202.2	**30.5**	15.1%
SCE	DRP	6/23/05	10-Day	40	203.2	**31.5**	15.5%
SCE	DRP	7/13/05	DRP 8-Day Adj	45	278.0	**36.9**	13.3%
SCE	DRP	7/13/05	QC 8-Day Adj	45	271.0	**35.7**	13.2%
SCE	DRP	7/13/05	QC 8-Day	45	262.2	**26.9**	10.3%
SCE	DRP	7/13/05	10-Day Adj	45	271.3	**36.1**	13.3%
SCE	DRP	7/13/05	10-Day	45	261.8	**26.5**	10.1%
SCE	DRP	7/14/05	DRP 8-Day Adj	66	460.0	**-17.3**	-3.8%
SCE	DRP	7/14/05	QC 8-Day Adj	66	450.9	**-20.9**	-4.6%
SCE	DRP	7/14/05	QC 8-Day	66	444.8	**-26.9**	-6.1%
SCE	DRP	7/14/05	10-Day Adj	66	451.1	**-20.6**	-4.6%
SCE	DRP	7/14/05	10-Day	66	443.2	**-28.5**	-6.4%
SCE	DRP	7/19/05	DRP 8-Day Adj	48	196.2	**31.1**	15.8%
SCE	DRP	7/19/05	QC 8-Day Adj	48	202.9	**42.9**	21.1%
SCE	DRP	7/19/05	QC 8-Day	48	209.4	**49.4**	23.6%
SCE	DRP	7/19/05	10-Day Adj	48	202.1	**42.1**	20.8%
SCE	DRP	7/19/05	10-Day	48	206.9	**46.9**	22.7%
SCE	DRP	7/20/05	DRP 8-Day Adj	45	191.6	**30.3**	15.8%
SCE	DRP	7/20/05	QC 8-Day Adj	45	198.3	**42.8**	21.6%
SCE	DRP	7/20/05	QC 8-Day	45	204.5	**48.9**	23.9%
SCE	DRP	7/20/05	10-Day Adj	45	197.5	**41.9**	21.2%
SCE	DRP	7/20/05	10-Day	45	202.1	**46.6**	23.0%

Exhibit D7-2 (con't)
SCE Daily DRP MWh Impact Estimates based on 10-Day Adjusted Baseline – Events 8-14

Utility	Program	Event	Baseline	n	Daily MWh Estimates		% Reduction
					Base Load	Impacts	
SCE	DRP	7/21/05	DRP 8-Day Adj	48	196.9	**29.8**	15.1%
SCE	DRP	7/21/05	QC 8-Day Adj	48	202.9	**41.2**	20.3%
SCE	DRP	7/21/05	QC 8-Day	48	209.4	**47.7**	22.8%
SCE	DRP	7/21/05	10-Day Adj	48	202.1	**40.4**	20.0%
SCE	DRP	7/21/05	10-Day	48	206.9	**45.2**	21.8%
SCE	DRP	7/22/05	DRP 8-Day Adj	13	48.2	**7.2**	14.9%
SCE	DRP	7/22/05	QC 8-Day Adj	13	50.1	**10.8**	21.6%
SCE	DRP	7/22/05	QC 8-Day	13	52.0	**12.7**	24.4%
SCE	DRP	7/22/05	10-Day Adj	13	49.9	**10.6**	21.2%
SCE	DRP	7/22/05	10-Day	13	51.3	**12.1**	23.5%
SCE	DRP	7/29/05	DRP 8-Day Adj	36	156.3	**38.0**	24.3%
SCE	DRP	7/29/05	QC 8-Day Adj	36	156.0	**37.7**	24.2%
SCE	DRP	7/29/05	QC 8-Day	36	159.7	**41.4**	25.9%
SCE	DRP	7/29/05	10-Day Adj	36	155.9	**37.7**	24.2%
SCE	DRP	7/29/05	10-Day	36	157.7	**39.4**	25.0%
SCE	DRP	8/17/05	DRP 8-Day Adj	51	301.6	**2.8**	0.9%
SCE	DRP	8/17/05	QC 8-Day Adj	51	301.7	**2.9**	1.0%
SCE	DRP	8/17/05	QC 8-Day	51	323.7	**25.0**	7.7%
SCE	DRP	8/17/05	10-Day Adj	51	301.2	**2.4**	0.8%
SCE	DRP	8/17/05	10-Day	51	323.5	**24.7**	7.6%
SCE	DRP	8/23/05	DRP 8-Day Adj	53	217.4	**34.3**	15.8%
SCE	DRP	8/23/05	QC 8-Day Adj	53	217.8	**34.7**	15.9%
SCE	DRP	8/23/05	QC 8-Day	53	220.9	**37.8**	17.1%
SCE	DRP	8/23/05	10-Day Adj	53	217.6	**34.5**	15.9%
SCE	DRP	8/23/05	10-Day	53	219.9	**36.8**	16.7%
SCE	DRP	8/25/05	DRP 8-Day Adj	28	183.4	**34.3**	18.7%
SCE	DRP	8/25/05	QC 8-Day Adj	28	185.3	**36.2**	19.5%
SCE	DRP	8/25/05	QC 8-Day	28	168.2	**19.1**	11.4%
SCE	DRP	8/25/05	10-Day Adj	28	183.8	**34.7**	18.9%
SCE	DRP	8/25/05	10-Day	28	166.6	**17.5**	10.5%
SCE	DRP	8/26/05	DRP 8-Day Adj	42	278.3	**41.7**	15.0%
SCE	DRP	8/26/05	QC 8-Day Adj	42	280.5	**44.0**	15.7%
SCE	DRP	8/26/05	QC 8-Day	42	254.7	**18.1**	7.1%
SCE	DRP	8/26/05	10-Day Adj	42	278.0	**41.4**	14.9%
SCE	DRP	8/26/05	10-Day	42	252.0	**15.4**	6.1%

Exhibit D7-2 (con't)
SCE Daily DRP MWh Impact Estimates based on 10-Day Adjusted Baseline – Events 15-19 and Overall Event Average

Utility	Program	Event	Baseline	n	Daily MWh Estimates		%
					Base Load	Impacts	Reduction
SCE	DRP	9/1/05	DRP 8-Day Adj	46	114.7	**16.7**	14.5%
SCE	DRP	9/1/05	QC 8-Day Adj	46	113.6	**15.6**	13.7%
SCE	DRP	9/1/05	QC 8-Day	46	110.0	**12.0**	10.9%
SCE	DRP	9/1/05	10-Day Adj	46	113.4	**15.4**	13.5%
SCE	DRP	9/1/05	10-Day	46	109.6	**11.6**	10.6%
SCE	DRP	9/6/05	DRP 8-Day Adj	42	96.1	**-5.0**	-5.2%
SCE	DRP	9/6/05	QC 8-Day Adj	42	97.6	**-3.5**	-3.6%
SCE	DRP	9/6/05	QC 8-Day	42	110.4	**9.3**	8.4%
SCE	DRP	9/6/05	10-Day Adj	42	97.5	**-3.6**	-3.7%
SCE	DRP	9/6/05	10-Day	42	109.1	**8.0**	7.3%
SCE	DRP	9/21/05	DRP 8-Day Adj	21	38.3	**7.7**	20.1%
SCE	DRP	9/21/05	QC 8-Day Adj	21	40.8	**10.2**	25.1%
SCE	DRP	9/21/05	QC 8-Day	21	39.4	**8.9**	22.5%
SCE	DRP	9/21/05	10-Day Adj	21	40.7	**10.1**	24.9%
SCE	DRP	9/21/05	10-Day	21	39.4	**8.9**	22.5%
SCE	DRP	9/22/05	DRP 8-Day Adj	14	33.0	**5.3**	16.0%
SCE	DRP	9/22/05	QC 8-Day Adj	14	35.3	**7.5**	21.3%
SCE	DRP	9/22/05	QC 8-Day	14	34.1	**6.3**	18.6%
SCE	DRP	9/22/05	10-Day Adj	14	35.1	**7.4**	21.0%
SCE	DRP	9/22/05	10-Day	14	34.0	**6.3**	18.5%
SCE	DRP	9/30/05	DRP 8-Day Adj	26	97.0	**14.9**	15.3%
SCE	DRP	9/30/05	QC 8-Day Adj	26	99.1	**17.0**	17.1%
SCE	DRP	9/30/05	QC 8-Day	26	88.8	**6.7**	7.5%
SCE	DRP	9/30/05	10-Day Adj	26	99.0	**16.8**	17.0%
SCE	DRP	9/30/05	10-Day	26	88.9	**6.8**	7.6%
SDGE	**DRP**	**Average**	**DRP 8-Day Adj**	**38**	**177**	**19**	**11.0%**
SDGE	**DRP**	**Average**	**QC 8-Day Adj**	**38**	**178**	**22**	**12.3%**
SDGE	**DRP**	**Average**	**QC 8-Day**	**38**	**177**	**21**	**12.0%**
SDGE	**DRP**	**Average**	**10-Day Adj**	**38**	**178**	**21**	**12.1%**
SDGE	**DRP**	**Average**	**10-Day**	**38**	**176**	**20**	**11.5%**

Exhibit D7-3
SDG&E Daily DRP MWh Impact Estimates based on 10-Day Adjusted Baseline – Events 1-7 and Overall Event Average

Utility	Program	Event	Baseline	n	Daily MWh Estimates		% Reduction
					Base Load	Impacts	
SDGE	DRP	6/30/05	DRP 8-Day Adj	3	12.6	**3.7**	29.0%
SDGE	DRP	6/30/05	QC 8-Day Adj	3	12.6	**3.6**	28.8%
SDGE	DRP	6/30/05	QC 8-Day	3	12.1	**3.2**	26.2%
SDGE	DRP	6/30/05	10-Day Adj	3	12.4	**3.5**	27.8%
SDGE	DRP	6/30/05	10-Day	3	12.0	**3.0**	25.3%
SDGE	DRP	7/14/05	DRP 8-Day Adj	6	28.3	**3.8**	13.5%
SDGE	DRP	7/14/05	QC 8-Day Adj	6	27.8	**3.3**	12.0%
SDGE	DRP	7/14/05	QC 8-Day	6	25.5	**1.0**	4.1%
SDGE	DRP	7/14/05	10-Day Adj	6	27.3	**2.8**	10.3%
SDGE	DRP	7/14/05	10-Day	6	25.6	**1.1**	4.3%
SDGE	DRP	7/20/05	DRP 8-Day Adj	6	28.7	**2.5**	8.6%
SDGE	DRP	7/20/05	QC 8-Day Adj	6	28.4	**2.2**	7.7%
SDGE	DRP	7/20/05	QC 8-Day	6	25.9	**-0.4**	-1.5%
SDGE	DRP	7/20/05	10-Day Adj	6	28.1	**1.9**	6.6%
SDGE	DRP	7/20/05	10-Day	6	26.1	**-0.2**	-0.7%
SDGE	DRP	7/21/05	DRP 8-Day Adj	9	44.9	**6.2**	13.9%
SDGE	DRP	7/21/05	QC 8-Day Adj	9	43.9	**5.2**	11.8%
SDGE	DRP	7/21/05	QC 8-Day	9	39.8	**1.1**	2.8%
SDGE	DRP	7/21/05	10-Day Adj	9	43.3	**4.6**	10.7%
SDGE	DRP	7/21/05	10-Day	9	40.1	**1.4**	3.5%
SDGE	DRP	7/22/05	DRP 8-Day Adj	12	60.7	**4.1**	6.8%
SDGE	DRP	7/22/05	QC 8-Day Adj	12	59.4	**2.7**	4.6%
SDGE	DRP	7/22/05	QC 8-Day	12	53.8	**-2.9**	-5.3%
SDGE	DRP	7/22/05	10-Day Adj	12	58.6	**1.9**	3.3%
SDGE	DRP	7/22/05	10-Day	12	54.2	**-2.5**	-4.6%
SDGE	DRP	8/26/05	DRP 8-Day Adj	15	71.6	**11.8**	16.5%
SDGE	DRP	8/26/05	QC 8-Day Adj	15	71.8	**12.0**	16.7%
SDGE	DRP	8/26/05	QC 8-Day	15	64.9	**5.1**	7.9%
SDGE	DRP	8/26/05	10-Day Adj	15	72.0	**12.2**	17.0%
SDGE	DRP	8/26/05	10-Day	15	65.3	**5.5**	8.5%
SDGE	DRP	8/29/05	DRP 8-Day Adj	15	71.7	**10.6**	14.8%
SDGE	DRP	8/29/05	QC 8-Day Adj	15	71.8	**10.7**	14.9%
SDGE	DRP	8/29/05	QC 8-Day	15	64.9	**3.9**	5.9%
SDGE	DRP	8/29/05	10-Day Adj	15	72.0	**10.9**	15.2%
SDGE	DRP	8/29/05	10-Day	15	65.3	**4.2**	6.5%
SDGE	**DRP**	**Average**	**DRP 8-Day Adj**	**9**	**45.5**	**6.1**	**13.4%**
SDGE	**DRP**	**Average**	**QC 8-Day Adj**	**9**	**45.1**	**5.7**	**12.6%**
SDGE	**DRP**	**Average**	**QC 8-Day**	**9**	**41.0**	**1.6**	**3.9%**
SDGE	**DRP**	**Average**	**10-Day Adj**	**9**	**44.8**	**5.4**	**12.1%**
SDGE	**DRP**	**Average**	**10-Day**	**9**	**41.2**	**1.8**	**4.4%**