2012 Statewide Load Impact Evaluation of California Aggregator Demand Response Programs
Volume 1: *Ex post* and *Ex ante* Load Impacts

CALMAC Study ID PGE0318.01

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April 1, 2013

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ABSTRACT

This report documents the results of a load impact evaluation of aggregator demand response ("DR") programs operated by the three California investor-owned utilities (IOUs), Pacific Gas and Electric ("PG&E"), Southern California Edison ("SCE"), and San Diego Gas and Electric ("SDG&E") for Program Year 2012.

In these programs, DR aggregators contract with the IOUs and with commercial and industrial customers to act on their behalf with respect to all aspects of the DR program, including receiving notices from the utility, arranging for load reductions on event days, receiving incentive payments, and paying penalties (if warranted) to the utility. Each aggregator forms a "portfolio" of individual customer accounts, whose aggregated load reductions participate as a single resource for the IOUs in the DR programs. Depending on their contractual arrangement with the IOU, aggregators can enroll and nominate customers in a mix of day-ahead ("DA") and day-of ("DO") triggered DR product types. The terms of the conditions of service can vary widely, depending on the individual contracts and tariffs negotiated between the aggregator and the IOU and customers.

The scope of this evaluation covers the state-wide Capacity Bidding Program ("CBP"), which is operated by all three IOUs, PG&E's Aggregator Managed Portfolio ("AMP"), and SCE's Demand Response Contracts ("DRC").

The primary goals of this evaluation study are the following:

- Estimate the *ex post* load impacts for program year 2012;
- Estimate *ex ante* load impacts for the programs for years 2013 through 2023; and
- Conduct baseline analyses for each aggregator program.

Enrollment in the day-of versions of all of the programs exceeded that in the day-ahead versions, and enrollment in the contract-based programs was generally higher than for the CBP programs. Enrollment ranged from less than 100 customer accounts for some product types, to more than 1,500 for the DO version of AMP and DRC.

With the exception of 12 events called for SCE's small CBP DA program, most CBP program types were called about six times. The two contract-based programs were called less frequently.

Hourly *ex post* load impacts were estimated for each program and event during the summer of 2012, using regression analysis of individual customer-level hourly load, weather, and event data. Estimated load impacts were reported for each event, for all programs and product types (*e.g.*, DA 1-4 hours and DO 2-6 hours). Load impacts for the average, or typical event were also reported by industry type and CAISO local capacity area where relevant.

EXECUTIVE SUMMARY

This report documents the results of a load impact evaluation of aggregator demand response ("DR") programs operated by the three California investor-owned utilities (IOUs), Pacific Gas and Electric ("PG&E"), Southern California Edison ("SCE"), and San Diego Gas and Electric ("SDG&E") for Program-Year 2012. In these programs, DR aggregators contract with the IOUs and with commercial and industrial customers to act on their behalf with respect to all aspects of the DR program, including receiving notices from the utility, arranging for load reductions on event days, receiving incentive payments, and paying penalties (if warranted) to the utility. Each aggregator forms a "portfolio" of individual customers, whose aggregated load reductions participate as a single resource for the IOUs in the DR programs. Aggregators, depending on their contractual arrangement with the IOU, can enroll and nominate customers in a mix of day-ahead ("DA") and day-of ("DO") triggered DR product types. The terms of the conditions of service can vary widely, depending on the individual contracts and tariffs negotiated between the aggregator and the IOU and customers.

The scope of this evaluation covers the state-wide Capacity Bidding Program ("CBP"), which is operated by all three IOUs, PG&E's Aggregator Managed Portfolio ("AMP"), and SCE's Demand Response Resource Contracts ("DRC").

The primary goals of this evaluation study are the following:

- Estimate the *ex post* load impacts for program year 2012;
- Estimate the *ex ante* load impacts for 2013 through 2023; and
- Assess the accuracy and bias of various versions of the programs' 10-in-10 baseline.

The aggregator baseline analysis is documented in Volume 2 of this report.

ES.1 Program Resources

CBP

The statewide CBP program provides month to month capacity payments ($/kW) to aggregators based on their nominated kW load, the specific operating month and the notice option (DA or DO). Additional energy payments ($/kWh) are made to bundled customers based on the measured kWh reductions (relative to the program baseline) that are achieved when an event is called. The monthly capacity payments can be adjusted by the actual kWh reductions during an event, and capacity penalties apply if events are called in a month and measured load reductions fall below 50 percent of nominated amounts. If no events are called, the aggregator receives the monthly capacity payment in accordance with their nomination, but no energy payments.

Participating aggregators may adjust their nomination each month, as well as their choice of available event type and event window options (*e.g.*, DA or DO events, and 1-

to-4, or 2-to-6, or 4-to-8 hour maximum event durations). CBP events may be called on non-holiday weekdays in the months of May through October, between the hours of 11 a.m. and 7 p.m., with a maximum of twenty-four event hours per month.

Customers enrolled in CBP may participate in another DR program, so long as it is an energy-payment program and does not have the same advanced notification (*i.e.*, day-ahead or day-of).

AMP

Under the AMP program, each aggregator operates their resource portfolio under a bilateral contract with PG&E and has negotiated their own aggregated DR program terms. Each AMP contract acts as an individual DR resource and is called under the terms of the contract, with either a DA or DO trigger. Up to 50 hours of events may be called each year, including test events, during the hours of 11 a.m. and 7 p.m. AMP events may be triggered by very high market prices and system emergencies. Customers who participate in AMP with *day-ahead* notice are allowed to dually enroll in PG&E's Optional Binding Mandatory Curtailment program, while AMP customers who select *day-of* notification may also participate in DBP or Peak Day Pricing (PDP). The settlement baselines are defined in the aggregator contracts, and may use an aggregated 3-in-10 or an aggregate 10-in-10 method.

DRC

Under DRC, third-party aggregators enter bilateral contracts with SCE, the terms of which may vary and are treated as confidential.

Program nominations

Table ES–1 summarizes the numbers of customer accounts nominated for the DA and DO notice types across all aggregator programs at the three utilities in 2012. The DO product types generally have greater numbers of customer accounts than the DA product type.

Table ES–1: Nominated Customer Accounts by Utility and Program Notice

		Nominated Accounts	
Program	**Utility**	**DA**	**DO**
CBP	PG&E	166	370
	SCE	4	399
	SDG&E	79	321
AMP	PG&E	233	1,125
DRC	SCE	153	1,650

ES.2 Summary of Study Findings

Events called

Table ES–2 summarizes the numbers of aggregator events called in 2012, by program and notice type. With the exception of the 12 events called for SCE's small CBP DA program, most CBP program types were called about six times. The two contract-based programs were called less frequently.

Table ES–2: Aggregator Events Called in 2012

Program	Utility	Number of Events DA	Number of Events DO
CBP	PG&E	5	6
	SCE	12	7
	SDG&E	6	5
AMP	PG&E	3	3
DRC	SCE	1	2

Estimated ex-post load impacts

Table ES–3 summarizes estimates of average hourly *ex post* load impacts for PY 2012, *for the typical event* for each of the three utilities' aggregator programs and notice types (*e.g.*, *day-ahead* and *day-of* notice). Load impacts are shown in both per-customer (kW) and aggregate (MW) levels. Also shown are nominated resource capacity amounts.[1] Estimated load impacts for the *DO* product types are generally greater than for *DA* products, which is consistent with the greater DO enrollment and total nominated load.

Table ES–3: Average Hourly Load Impacts – by Utility and Notice (2012)

		Per-Customer (kW)		Aggregate (MW)		Nominated Capacity (MW)	
Program	Utility	DA	DO	DA	DO	DA	DO
CBP	PG&E	121.5	62.8	20.4	23.3	22.2	26.0
	SCE	18.3	45.9	0.04	16.5	0.1	11.7
	SDG&E	80.8	30.5	6.4	9.8	7.5	11.7
AMP	PG&E	214.4	114.2	49.9	129.6	44.0	141.5
DRC	SCE	153.5	97.2	21.8	160.1	50.0	225.0

Ex ante nominations and load impacts

Table ES–4 shows *ex ante* nominations and aggregate load impacts for 2013, the first year of the forecast time horizon.

[1] Aggregators in the CBP program may change nominations on a monthly basis. The values shown are for August. Nominations for AMP and DRC are contractually based.

Table ES–4: *Ex ante* Nominations and Load Impacts –2013

Utility	Nominations		Aggregate Load Impacts (MW)	
	DA	DO	DA	DO
PG&E - CBP	168	374	19.6	28.9
SCE - CBP	3	255	0.0	10.9
SDG&E -CBP	81	371	7.7	10.4
PG&E - AMP	459	1,639	72.2	175.2
SCE - DRC	123	1,468	15.9	129.2

ES.3 Evaluation Methodology

Estimates of total program-level load impacts for each program were developed from the estimated coefficients of individual customer-level regression equations. These equations were estimated using individual customer load data and associated weather data for the summer months for 2012, for each customer account nominated in a month containing an event.

The regression equations are based on models of hourly loads as functions of a list of variables designed to control for factors such as:

- Seasonal and hourly time patterns (*e.g.*, month, day-of-week, and hour, plus various hour/day-type interactions)
- Weather (*e.g.*, cooling degree hours)
- Event indicators, which are invoked when a given nominated customer's product type was called, are interacted with hourly indicator variables to allow estimation of hourly load impacts for each event-day.

The resulting equations provide the capability of estimating hourly load impacts on every event day, as well as simulating hourly reference load profiles for various day-types and weather conditions. In addition, the customer-specific equations provide the capability to summarize load impacts by characteristics such as industry type and CAISO local capacity area, by adding across customers in any given category. Similarly, load impacts associated with TA/TI and AutoDR participation may be obtained by summing load impacts across those participants. Finally, uncertainty-adjusted load impacts are calculated to illustrate the degree of uncertainty that exists around the estimated load impacts.

1. INTRODUCTION AND OBJECTIVES OF THE STUDY

This report documents the results of a load impact evaluation of aggregator demand response ("DR") programs operated by the three California investor-owned utilities (IOUs), Pacific Gas and Electric ("PG&E"), Southern California Edison ("SCE"), and San Diego Gas and Electric ("SDG&E") for Program Year 2012. In these programs, DR aggregators contract with the IOUs and with commercial and industrial customers to act on their behalf with respect to all aspects of the DR program, including receiving notices from the utility, arranging for load reductions on event days, receiving incentive payments, and paying penalties (if warranted) to the utility. Each aggregator forms a "portfolio" of individual customers, whose aggregated load reductions participate as a single resource for the IOUs in the DR programs. Aggregators, depending on their contractual arrangement with the IOU, can enroll and nominate customers in a mix of day-ahead ("DA") and day-of ("DO") triggered DR product types. The terms of the conditions of service can vary widely, depending on the individual contracts and tariffs negotiated between the aggregator and the IOU and customers.

The scope of this evaluation covers the state-wide Capacity Bidding Program ("CBP"), which is operated by all three IOUs, PG&E's Aggregator Managed Portfolio ("AMP"), and SCE's Demand Response Resource Contracts ("DRC").

The primary goals of this evaluation study are the following:

- Estimate the *ex post* load impacts for program year 2012;
- Estimate the *ex ante* load impacts for 2013 through 2023[2]; and
- Assess the accuracy and bias of various versions of the 10-in-10 baseline.

The first goal involves estimating *hourly load impacts* for each 2012 individual DR event, for each of the utilities' aggregator programs, as well as the distribution of load impacts for a "typical" DR event across industry types and CAISO local capacity areas. Our primary approach involved estimating *individual customer regressions*, which provided a flexible basis for analyzing and reporting load impact results at various levels (*e.g.*, total program level) and by various subgroups (*e.g.*, by industry group and CAISO local capacity area), including those customers that also participated in the AutoDR and Technical Assistance and Technology Incentives (TA/TI) programs.

The second goal involves producing *forecasts of load impacts* for each of the programs through 2023, by combining the information on historical *ex post* load impacts with utility projections of program enrollment or contracted load nominations.

The third goal involves analysis to assess the accuracy and bias of the current 10-in-10 program baseline method and several potential alternative baselines, including various

[2] As requested by SDG&E, we also produce an *ex ante* "forecast" for 2012 using enrollments for that year and per-customer load impacts for a typical event, by weather scenario.

same-day adjustments, for each of the aggregator programs. The baseline analysis involves two types of load comparisons. One type involves comparing *estimated* reference loads from the *ex post* evaluation (the "true baseline") to the alternative baseline loads on event days. The other compares the alternative baseline loads to *observed* loads on a set of event-like non-event days. In each case, we assess the performance of the alternative baseline methods in terms of accuracy (*i.e.*, degree of error, regardless of sign) and bias (*i.e.*, the tendency of a baseline method to under-state or over-state true baselines). Baseline analysis results are reported in Volume 2 of this report.

2. AGGREGATOR DR PROGRAM RESOURCES

This section summarizes the aggregator programs covered in this evaluation, including the characteristics of the participants in the programs.

2.1 Capacity Bidding Program (CBP)

The statewide CBP program provides monthly capacity payments ($/kW) to participants based on the nominated kW load, the specific operating month, and the program notice option (DA or DO).[3] Additional energy payments ($/kWh) are made to bundled[4] customers based on the measured kWh reductions (relative to the program baseline) that are achieved when an event is called. The monthly capacity payments can be adjusted by the actual kWh reductions during an event, and capacity penalties apply if events are called in a month and measured load reductions fall below 50 percent of nominated amounts. If no events are called, the aggregator receives the monthly capacity payment in accordance with their nomination, but no energy payments.

Participating aggregators may adjust their nominations each month, as well as their choice of available notice type and event window options (*e.g.*, DA or DO event notice, and 1-to-4, 2-to-6, or 4-to-8 hour maximum event durations). CBP events may be called on non-holiday weekdays in the months of May through October, between the hours of 11 a.m. and 7 p.m., with a maximum of twenty-four event hours per month.

Customers enrolled in CBP may participate in another DR program, so long as it is an energy-payment program and does not have the same advanced notification (*i.e.*, day-ahead or day-of).

Table 2–1 summarizes the characteristics of the customer accounts that were nominated to participate in CBP at each utility in 2012, by type of notice and industry group. The values in the tables represent nominations for the typical event, as reported in the Protocol tables in Section 4.[5]

[3] Participants may be individual customers or aggregators, but most all are aggregators.
[4] The program is also open to Direct Access and Community Choice Aggregation customers.
[5] We report nominations because customers are not assigned to DA or DO product types until they are nominated in a particular month. The typical number of customer accounts may not equal the number called for any particular event. Those numbers are shown in the load impact tables.

Retail stores make up a large share of CBP DO enrolled load at each of the utilities. The PG&E DA product type has a large number of nominees in Agriculture, Mining, and Construction, while SDG&E's DA product is dominated by Offices, Hotels, Health, and Services.

Table 2–1: CBP Nominated Customer Accounts by Utility and Industry Group

Utility	Industry Type	Day-Ahead		Day-Of	
		Accounts	Summer Peak Demand (MW)	Accounts	Summer Peak Demand (MW)
PG&E	1. Agriculture, Mining & Construction	133	21.89	38	8.04
	2. Manufacturing	11	20.10	16	14.22
	3. Wholesale, Transport, other Utilities	14	7.23	23	12.39
	4. Retail stores			247	57.77
	5. Offices, Hotels, Health, Services	3	2.20	16	12.89
	6. Schools	1	2.86		
	7. Entertainment, Other Services, Gov't	1	0.46	29	6.18
	8. Other/Unknown	3	0.40	2	0.21
	Total	166	55.1	370	111.7
SCE	1. Agriculture, Mining & Construction	1	0.31	2	0.43
	2. Manufacturing				
	3. Wholesale, Transport, other Utilities			4	1.24
	4. Retail stores			346	89.9
	5. Offices, Hotels, Health, Services	3	1.85	1	0.26
	6. Schools				
	7. Entertainment, Other Services, Gov't			46	5.54
	8. Other/Unknown				
	Total	4	2.2	399	97.4
SDG&E	1. Agriculture, Mining & Construction				
	2. Manufacturing	4	7.43	10	3.24
	3. Wholesale, Transport, other Utilities	5	1.30	14	2.23
	4. Retail stores	1	0.84	266	61.09
	5. Offices, Hotels, Health, Services	65	18.05	26	11.70
	6. Schools				
	7. Entertainment, Other Services, Gov't	3	0.66	3	1.48
	8. Other/Unknown	1	0.09	3	0.54
	Total	79	28.4	321	80.3

Table 2–2 lists the definitions of the industry groups, which are defined as aggregations of the indicated North American Industry Classification System (NAICS) codes.

Table 2–2: Industry Type Definitions

Industry Types	NAICS Codes
1. Agriculture, Mining & Construction	11, 21, 23
2. Manufacturing	31-33
3. Wholesale, Transport, other utilities	22, 42, 48-49
4. Retail stores	44-45
5. Offices, Hotels, Finance, Services	51-56, 62, 72
6. Schools	61
7. Institutional/Government	71, 81, 92
8. Other or unknown	

2.2 PG&E's Aggregator Managed Portfolio (AMP)

Under the AMP program, each aggregator operates their resource portfolio under a bilateral contract with PG&E and has negotiated their own aggregated DR program terms. Each AMP contract acts as an individual DR resource and is called under the terms of the contract, with either a DA or DO trigger. PG&E has contracts with one DA and three DO aggregators, who have respectively contracted for approximately 44 MW and 140 MW of load reduction capacity. Up to 50 hours of events may be called each year, including test events, during the hours of 11 a.m. and 7 p.m. AMP events may be triggered by very high market prices and system emergencies. Customers who participate in AMP with *day-ahead* notice are allowed to dually enroll in PG&E's Optional Binding Mandatory Curtailment program, while AMP customers who select *day-of* notification may also participate in DBP or Peak Day Pricing (PDP). The settlement baselines are defined in the aggregator contracts, and may use an aggregated 3-in-10 or an aggregate 10-in-10 method.

Table 2–3 shows customers nominated for the DA and DO notice options of PG&E's AMP program, by industry type. Nearly half of those nominated for the AMP DA product type are manufacturing customers, while DO nominations are spread over several industry types.

Table 2–3: PG&E AMP Nominated Customer Accounts by Industry Group

Industry Type	Day-Ahead Accounts	Day-Ahead Summer Peak Demand (MW)	Day-Of Accounts	Day-Of Summer Peak Demand (MW)
1. Agriculture, Mining & Construction	33	2.5	279	87.1
2. Manufacturing	95	90.4	134	120.4
3. Wholesale, Transport, other Utilities	16	6.0	140	75.5
4. Retail stores	29	11.9	260	58.8
5. Offices, Hotels, Health, Services	17	8.6	218	105.1
6. Schools	31	9.5	32	21.2
7. Entertainment, Other Services, Gov't	11	8.8	53	34.7
8. Other/Unknown			10	2.3
Total	233	137.8	1,125	505.0

2.3 SCE's Demand Response Resource Contracts (DRC)

Under DRC, third-party aggregators enter bilateral contracts with SCE, the terms of which may vary and are treated as confidential. SCE has four contracts under DRC, with both day-ahead and day-of options, which in total include about 1,800 nominated customer service accounts, with DR resource capacities of 50 MW for DA and 225 MW for DO notice types.

Table 2–4 shows customer nominations by industry type for the DA and DO notice options of SCE's DRC program. The majority of DRC DA contracts are with customers in the Agriculture, Mining, and Construction industry type. Nominations for DRC DO are spread over several industry types.

Table 2–4: SCE DRC Nominations by Industry Group

Industry Type	Day-Ahead Accounts	Day-Ahead Summer Peak Demand (MW)	Day-Of Accounts	Day-Of Summer Peak Demand (MW)
1. Agriculture, Mining & Construction	93	5.5	92	25.4
2. Manufacturing	15	20.6	129	98.1
3. Wholesale, Transport, other Utilities	27	3.2	493	117.7
4. Retail stores			710	192.1
5. Offices, Hotels, Health, Services	13	3.6	168	70.1
6. Schools			26	47.8
7. Entertainment, Other Services, Gov't	1	0.1	33	16.2
8. Other/Unknown	4	0.2		
Total	153	33.1	1,650	567.4

3. STUDY METHODS

3.1 Overview

The primary evaluation method used in the *ex post* portion of this study involved customer-level regression analysis applied to hourly load data to estimate hourly load impacts. The regression equations model hourly load as a function of a set of variables designed to control for factors affecting consumers' hourly demand levels, such as:

- Seasonal and hourly time patterns (*e.g.*, year, month, day-of-week, and hour, plus various hour/day-type interactions);
- Weather, including hour-specific weather coefficients;
- Event variables. A series of dummy variables was included to account for each hour of each event day, allowing us to estimate the load impacts for all hours across the event days.

The models use the level of hourly demand (kW) as the dependent variable and a separate equation is estimated for each nominated customer. As a result, the estimated coefficients on the event day/hour variables are direct estimates of the *ex post* load impacts, and their standard errors indicate the precision of the estimates. For example, a CBP hour-15 event coefficient of -100 would imply that the customer reduced load by 100 kWh during hour 15 of that event day relative to its normal usage in that hour. Weekends and holidays were excluded from the estimation database.[6]

We tested a variety of weather variables in an attempt to determine which set best explains usage on event-like non-event days. This process and its results are explained in Appendix A. The methods used to develop the *ex ante* load impact forecasts are described in Section 6.

3.2 Description of methods

3.2.1 Regression Model

The model shown below was separately estimated for each nominated customer. Table 3–1 describes the terms included in the equation.

[6] Including weekends and holidays would require the addition of variables to capture the fact that load levels and patterns on weekends and holidays can differ greatly from those of non-holiday weekdays. Because event days do not occur on weekends or holidays, the exclusion of these data does not affect the model's ability to estimate *ex post* load impacts.

$$Q_t = a + \sum_{Evt=1}^{E} \sum_{i=1}^{24} (b_{i,Evt}^{AGG} \times h_{i,t} \times AGG_t) + \sum_{i=1}^{24} (b_i^{MornLoad} \times h_{i,t} \times MornLoad_{i,t})$$

$$+ \sum_{i=1}^{24} (b_i^{OTH} \times h_{i,t} \times OtherEvt_{i,t}) + \sum_{i=1}^{24} (b_i^{Weather} \times h_{i,t} \times Weather_t) + \sum_{i=2}^{24} (b_i^{MON} \times h_{i,t} \times MON_t)$$

$$+ \sum_{i=2}^{24} (b_i^{FRI} \times h_{i,t} \times FRI_t) + \sum_{i=2}^{24} (b_i^{SUMMER} \times h_{i,t} \times SUMMER_t) + \sum_{i=2}^{24} (b_i^{h} \times h_{i,t})$$

$$+ \sum_{i=2}^{5} (b_i^{DTYPE} \times DTYPE_{i,t}) + \sum_{i=6}^{10} (b_i^{MONTH} \times MONTH_{i,t}) + e_t$$

Table 3–1: Descriptions of Terms included in the *Ex post* Regression Equation

Variable Name / Term	Variable / Term Description
Q_t	the demand in hour t for a customer enrolled in the aggregator program prior to the last event date
The various b's	The estimated parameters
$h_{i,t}$	a dummy variable for hour i
AGG_t	an indicator variable for program event days
$Weather_t$	The weather variables selected using our model screening process
E	The number of event days that occurred during the program year
$MornLoad_t$	a variable equal to the average of the day's load in hours 1 through 10
$OtherEvt_t$	equals one in the event hours of other demand response programs in which the customer is enrolled
MON_t	a dummy variable for Monday
FRI_t	a dummy variable for Friday
$SUMMER_t$	a dummy variable for the summer pricing season[7]
$DTYPE_{i,t}$	a series of dummy variables for each day of the week
$MONTH_{i,t}$	a series of dummy variables for each month
e_t	The error term.

The OtherEvt variables help the model explain load changes that occur on event days in cases in which aggregator customers are dually enrolled. (In the absence of these variables, any load reductions that occur on such days may be falsely attributed to other included variables, such as weather condition or day type variables.) The "morning load" variables are included in the same spirit as the day-of adjustment to the 10-in-10 baseline settlement method. That is, those variables help adjust the reference loads (or the loads that would have been observed in the absence of an event) for factors that affect pre-event usage, but are not accounted for by the other included variables.

[7] This is July through September for SCE, May through September for SDG&E, and May through October for PG&E.

The model allows for the hourly load profile to differ by: day of week, with separate profiles for Monday, Tuesday through Thursday, and Friday; and by pricing season (*i.e.*, summer versus non-summer), in order to account for customer load changes in response to seasonal price changes.

The model specification shown above has the level of load in a particular hour as the dependent variable. As part of our model validation process (explained in Appendix A), we tested models in which the dependent variable is the difference between the current hour's load and the load during the same hour on the previous day. We refer to these as models of "differences," in which these differences are calculated for all of the variables included in the model. Therefore, instead of estimating the equation using Q_t as the dependent variable (as in the levels model), the model is estimated using dQ_t, which is calculated from hourly data as follows:

$$dQ_t = Q_t - Q_{t-24}$$

Every explanatory variable in the estimating equation is transformed in the same fashion and the model is estimated using the differenced data.

Separate models were estimated for each customer. The load impacts were aggregated across customer accounts as appropriate to arrive at program-level load impacts, as well as load impacts by industry group and local capacity area (LCA).

3.2.2 Development of Uncertainty-Adjusted Load Impacts

The Load Impact Protocols require the estimation of uncertainty-adjusted load impacts. In the case of *ex post* load impacts, the parameters that constitute the load impact estimates are not estimated with certainty. We base the uncertainty-adjusted load impacts on the variances associated with the estimated load impact coefficients.

Specifically, we added the variances of the estimated load impacts across the customers nominated for the event in question. These aggregations were performed at either the program level, by industry group, or by LCA, as appropriate. The uncertainty-adjusted scenarios were then simulated under the assumption that each hour's load impact is normally distributed with the mean equal to the sum of the estimated load impacts and the standard deviation equal to the square root of the sum of the variances of the errors around the estimates of the load impacts. Results for the 10^{th}, 30^{th}, 70^{th}, and 90^{th} percentile scenarios are generated from these distributions.

4. STUDY RESULTS – CBP *EX POST* LOAD IMPACTS

This section describes the estimated *ex post* load impacts for each utility's CBP program and product type. For each program and product type (*e.g.*, DA 1-4 Hours and DO 1-4 Hours), we show the following information:

- Events that were called in 2012;
- For each event, the number of customer accounts called, average hourly (for the event hours) reference load, estimated load impact, and percentage load impact, all in aggregate and per-customer level;
- For the average, or typical, event, the average event-hour reference load, estimated load impact, and percentage load impact, by industry type and LCA;
- For selected (or typical) events, the hourly profile of the estimated reference load and load impacts; and
- Estimates of TA/TI and AutoDR impacts.

4.1 Capacity Bidding Program (CBP) – PG&E

4.1.1 Events for PG&E CBP

Table 4–1 lists the features of PG&E's CBP DA and DO events in 2012, including event hours, number of aggregators, and monthly nominated capacity. All DA and DO product types were called for five events in July and August, while only the DO product types were called for one additional event on August 13.

Table 4–1: Event Summary for 2012 – *PG&E CBP*

Date	Day of Week	Notice	Product	Hours Ending	Num. of Aggregators	Nom. Capacity (MW)
07/10/12	Tuesday	DA	1-4 Hour	16 - 19	5	29.3
		DO	1-4 Hour	15 - 18	6	22.3
			2-6 Hour		1	2.3
07/11/12	Wednesday	DA	1-4 Hour	15 - 18	5	29.3
		DO	1-4 Hour	16 - 19	6	22.3
			2-6 Hour		1	2.3
07/12/12	Thursday	DA	1-4 Hour	16 - 19	5	29.3
		DO	1-4 Hour	16 - 19	6	22.3
			2-6 Hour		1	2.3
08/09/12	Thursday	DA	1-4 Hour	16 - 19	5	22.2
		DO	1-4 Hour	16 - 19	6	23.7
			2-6 Hour	13 - 19	1	2.3
08/10/12	Friday	DA	1-4 Hour	16 - 19	5	22.2
		DO	1-4 Hour	16 - 19	6	23.7
			2-6 Hour	13 - 19	1	2.3
08/13/12	Monday	DO	1-4 Hour	16 - 19	6	23.7
			2-6 Hour		1	2.3

4.1.2 Summary load impacts

Table 4–2 shows average hourly estimated *reference loads*, *load impacts*, at both an average customer and aggregate level, as well as *percentage load impacts* for the DA and DO notice and associated product types, for each of PG&E's CBP events, and for averages across each of the respective events. Also shown are average event temperatures, and nominated capacity. The average hourly DA load impact for the average event was 20.4 MW, while DO load impacts averaged 17.7 MW for the 1-4 Hour product, and 5.5 MW for the 2-6 Hour product. Average percentage load impacts ranged from 20 to 44 percent across the three product types.

Table 4–2: Average Hourly Load Impacts by Event – *PG&E CBP*

				Average Customer		Aggregate				
Event Date	Notice	Product	Accounts Called	Reference Load (kW)	Load Impact (kW)	Reference Load (MW)	Load Impact (MW)	% Load Impact	Average Event Temp.	Nom. Capacity (MW)
07/10/12	DA	1-4 Hour	177	282.0	153.6	49.9	27.2	54.5%	93.9	29.3
	DO	1-4 Hour	297	245.0	51.0	72.8	15.1	20.8%	87.2	22.3
		2-6 Hour	96	283.1	55.7	27.2	5.3	19.7%	90.6	2.3
07/11/12	DA	1-4 Hour	177	283.1	119.6	50.1	21.2	42.3%	95.8	29.3
	DO	1-4 Hour	297	251.6	58.7	74.7	17.4	23.3%	88.5	22.3
		2-6 Hour	96	288.0	57.1	27.6	5.5	19.8%	92.6	2.3
07/12/12	DA	1-4 Hour	177	277.0	108.7	49.0	19.2	39.2%	94.7	29.3
	DO	1-4 Hour	297	251.3	56.5	74.6	16.8	22.5%	83.9	22.3
		2-6 Hour	96	284.6	61.6	27.3	5.9	21.6%	86.7	2.3
08/09/12	DA	1-4 Hour	154	291.8	119.6	44.9	18.4	41.0%	94.8	22.2
	DO	1-4 Hour	250	292.8	74.9	73.2	18.7	25.6%	89.5	23.7
		2-6 Hour	96	287.5	59.3	27.6	5.7	20.6%	91.0	2.3
08/10/12	DA	1-4 Hour	154	260.5	103.5	40.1	15.9	39.7%	95.1	22.2
	DO	1-4 Hour	250	288.2	78.3	72.0	19.6	27.2%	87.6	23.7
		2-6 Hour	96	288.1	61.1	27.7	5.9	21.2%	89.5	2.3
08/13/12	DO	1-4 Hour	250	284.9	74.7	71.2	18.7	26.2%	88.8	23.7
		2-6 Hour	96	288.9	49.9	27.7	4.8	17.3%	91.0	2.3
Average	DA	1-4 Hour	168	279.1	121.5	46.8	20.4	43.6%	94.9	25.8
	DO	1-4 Hour	274	267.3	64.8	73.1	17.7	24.2%	87.5	23.0
		2-6 Hour	96	286.7	57.4	27.5	5.5	20.0%	90.3	2.3

Table 4–3 shows the distribution of average hourly load impacts for the average DA and DO event by industry type. DA load impacts are concentrated in the Agriculture, Mining and Construction, and Manufacturing industry types, while DO load impacts are spread across several industry types.

Table 4–3: Distribution of Average Hourly Load Impacts by Industry Type – *PG&E CBP*

Notice	Industry	Accounts Called	Average Customer Reference Load (kW)	Average Customer Load Impact (kW)	Aggregate Reference Load (MW)	Aggregate Load Impact (MW)	% Load Impact	Average Event Temp.
DA	Agriculture, Mining & Construction	135	136.9	88.2	18.45	11.89	64.4%	94.0
	Manufacturing	11	1613.2	435.0	18.07	4.87	27.0%	97.2
	Wholesale, Transport, other utilities	14	381.4	200.5	5.26	2.77	52.6%	104.0
	Retail stores							
	Offices, Hotels, Finance, Services	3	617.0	40.2	1.85	0.12	6.5%	67.6
	Schools	1	2473.1	524.9	2.47	0.52	21.2%	101.6
	Institutional/Government	1	456.7	-6.8	0.46	-0.01	-1.5%	67.2
	Other or unknown	3	88.4	76.3	0.27	0.23	86.3%	92.1
	Total DA	**168**	**279.1**	**121.5**	**46.8**	**20.4**	**43.6%**	**94.9**
DO	Agriculture, Mining & Construction	38	188.9	128.5	7.18	4.88	68.0%	105.5
	Manufacturing	16	839.5	98.4	13.01	1.53	11.7%	92.7
	Wholesale, Transport, other utilities	23	385.7	236.3	8.68	5.32	61.3%	100.7
	Retail stores	247	228.9	41.4	56.53	10.23	18.1%	89.6
	Offices, Hotels, Finance, Services	16	669.4	62.7	10.71	1.00	9.4%	72.2
	Schools							
	Institutional/Government	29	152.7	9.7	4.43	0.28	6.3%	81.1
	Other or unknown	2	98.6	8.1	0.20	0.02	8.2%	75.1
	Total DO	**370**	**272.3**	**62.8**	**100.7**	**23.3**	**23.1%**	**88.3**

Table 4–4 shows the distribution of average hourly load impacts by LCA. More than half of the DA load impacts were located in the Greater Fresno LCA, and another quarter occurred outside of any LCA. DO load impacts were more widely spread, with the greatest amount in the Greater Bay Area.

Table 4–4: Distribution of Average Hourly Load Impacts by LCA – *PG&E CBP*

Notice	LCA	Accounts Called	Average Customer Reference Load (kW)	Average Customer Load Impact (kW)	Aggregate Reference Load (MW)	Aggregate Load Impact (MW)	% Load Impact	Average Event Temp.
DA	Greater Bay Area	9	490.0	47.1	4.41	0.42	9.6%	73.7
	Greater Fresno	102	184.5	117.6	18.85	12.02	63.7%	104.9
	Humboldt							
	Kern	45	104.0	54.0	4.72	2.45	51.9%	101.7
	Northern Coast	1	124.9	88.6	0.12	0.09	70.9%	92.0
	Not in any LCA	10	1,834.7	530.7	18.71	5.41	28.9%	94.9
	Sierra							
	Stockton							
	Total DA	**168**	**279.1**	**121.5**	**46.8**	**20.4**	**43.6%**	**94.9**
DO	Greater Bay Area	154	312.0	57.6	47.89	8.84	18.5%	80.8
	Greater Fresno	44	323.5	131.6	14.23	5.79	40.7%	105.3
	Humboldt	4	132.9	22.2	0.47	0.08	16.7%	60.4
	Kern	42	174.3	57.8	7.24	2.40	33.1%	103.0
	Northern Coast	31	229.4	37.7	7.11	1.17	16.4%	90.2
	Not in any LCA	64	261.6	52.5	16.61	3.34	20.1%	89.4
	Sierra	19	245.7	45.0	4.67	0.85	18.3%	100.3
	Stockton	14	180.1	56.2	2.52	0.79	31.2%	99.9
	Total DO	**370**	**272.3**	**62.8**	**100.7**	**23.3**	**23.1%**	**88.3**

4.1.3 Hourly load impacts

Figures 4–1 and 4–2 illustrate the hourly profiles of the estimated reference load, observed load and estimated load impacts (in MW) of the PG&E CBP DA 1-4 and DO 1-4 product types for the four-hour July 12 event, which was called for hours-ending 16 to 19. The data underlying the figures are available in the Excel-based Protocol table generators that are included as appendices to this report.

Figure 4–1: Hourly Loads and Load Impacts – PG&E CBP DA 1-4
July 12 Event

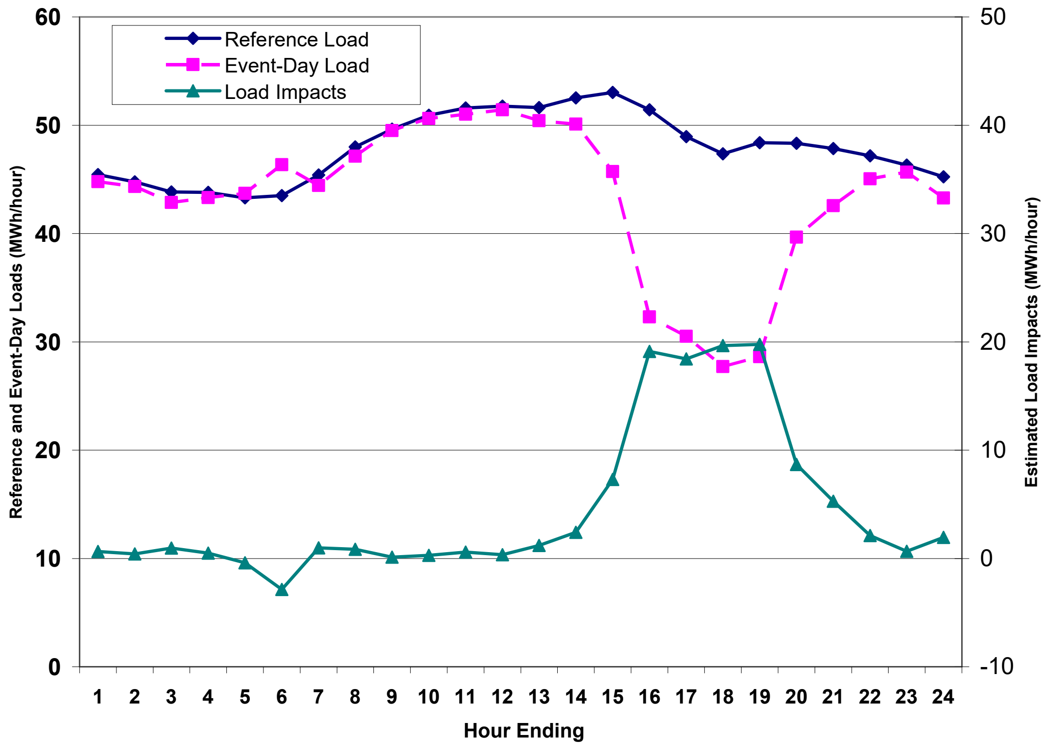
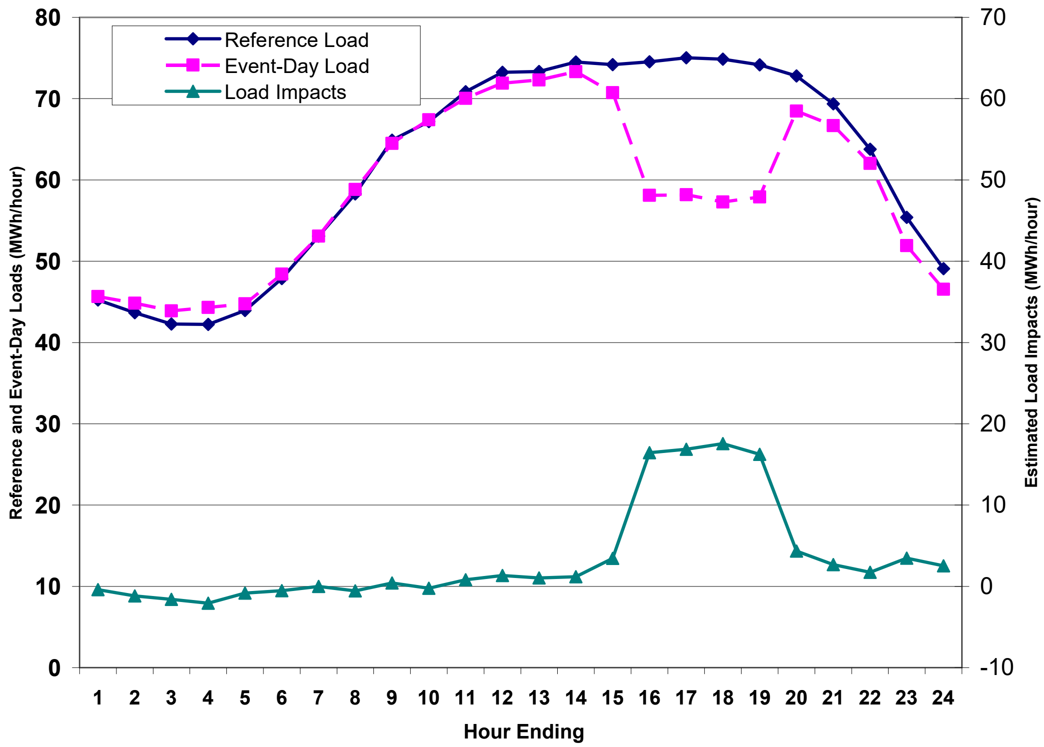


Figure 4–2: Hourly Loads and Load Impacts – PG&E CBP DO 1-4
July 12 Event



4.1.4 Load impacts of TA/TI and AutoDR participants

This section describes the *ex post* load impacts achieved by PG&E CBP customer accounts that participated in two demand response incentive programs: TA/TI and AutoDR.

The Technical Assistance and Technology Incentives (TA/TI) program has two parts: technical assistance in the form of energy audits, and technology incentives. The TA portion of the program subsidizes customer energy audits that have the objective of identifying ways in which customers can reduce load during demand response events. The TI portion of the program then provides incentive payments for the installation of equipment or control software supporting DR.

The Automated Demand Response (AutoDR) program helps customers to activate DR strategies, such as managing lighting or heating, ventilation and air conditioning (HVAC) systems, whereby electrical usage can be automatically reduced or eliminated during times of high electricity prices or electricity system emergencies.

Tables 4–5 and 4–6 summarize event-specific *total* load impacts for TA/TI and AutoDR participants, respectively. These represent the sum of the estimated load impacts for customers in each program, as estimated using the customer-level *ex post* regression methods.

Table 4–5 shows that an average of nine CBP customers participated in TA/TI and achieved load impacts for the average event of 1.4 MW, representing 54 percent of their reference load. The rightmost column shows the total load shed approved following the TA/TI DR test.

Table 4–5: Load Impacts of TA/TI Participants – *PG&E CBP*

Event Date	Number of SAIDs	Estimated Reference Load (kW)	Observed Load (kW)	Estimated Load Impact (kW)	% Load Impact	Approved Load Shed (kW)
7/10/2012	9	2,868	849	2,019	70.4%	2,591
7/11/2012	9	2,580	991	1,589	61.6%	2,591
7/12/2012	9	2,957	1,968	988	33.4%	2,591
8/9/2012	12	3,129	1,497	1,632	52.2%	3,425
8/10/2012	12	2,915	1,243	1,672	57.4%	3,425
8/13/2012	3	1,578	1,125	453	28.7%	1,025
Average	**9**	**2,671**	**1,279**	**1,392**	**52.1%**	**2,608**

Table 4–6 shows comparable information for CBP customers who have participated in AutoDR. An average of 35 customers are AutoDR participants, and their estimated load impacts for the average event are 4.1 MW, representing 61 percent of their reference load.

Table 4–6: Load Impacts of AutoDR Participants – *PG&E CBP*

Event Date	Number of SAIDs	Estimated Reference Load (kW)	Observed Load (kW)	Estimated Load Impact (kW)	% Load Impact	Approved Load Shed (kW)
7/10/2012	44	8,834	2,946	5,888	66.7%	15,852
7/11/2012	44	8,642	2,883	5,759	66.6%	15,852
7/12/2012	44	8,140	3,190	4,950	60.8%	15,852
8/9/2012	36	6,509	2,504	4,005	61.5%	13,871
8/10/2012	36	6,083	2,731	3,352	55.1%	13,871
8/13/2012	7	2,515	1,683	832	33.1%	5,146
Average	**35**	**6,787**	**2,656**	**4,131**	**60.9%**	**13,407**

4.2 Capacity Bidding Program (CBP) – SCE

4.2.1 Events for SCE CBP

Table 4–7 lists the events called for SCE's CBP program. The DA option, with its small nominated capacity, was called twelve times over the period from July through October. The DO product types were called seven times.

Table 4–7: Event Summary for 2012 – SCE CBP

Date	Day of Week	Notice	Product	Hours Ending	Num. of Aggregators	Nom. Capacity (MW)
07/20/2012	Friday	DO	1-4 Hour	17-19	3	4.26
			2-6 Hour	17-19	1	7.48
07/23/2012	Monday	DA	1-4 Hour	15-18	1	0.08
07/24/2012	Tuesday	DA	1-4 Hour	15-18	1	0.08
07/25/2012	Wednesday	DA	1-4 Hour	16-17	1	0.08
07/30/2012	Monday	DA	1-4 Hour	15-18	1	0.08
07/31/2012	Tuesday	DA	1-4 Hour	15-17	1	0.08
08/07/2012	Tuesday	DO	1-4 Hour	14-17	4	4.82
			2-6 Hour	14-19	1	7.48
08/13/2012	Monday	DO	1-4 Hour	15-18	4	4.82
			2-6 Hour	14-19	1	7.48
08/14/2012	Tuesday	DO	1-4 Hour	18-19	4	4.82
			2-6 Hour	18-19	1	7.48
09/14/2012	Friday	DO	1-4 Hour	15-18	4	4.42
			2-6 Hour	14-19	1	7.48
10/01/2012	Monday	DA	1-4 Hour	14-17	2	0.09
10/02/2012	Tuesday	DA	1-4 Hour	14-17	2	0.09
		DO	1-4 Hour	15-18	4	4.24
			2-6 Hour	15-18	1	7.48
10/03/2012	Wednesday	DA	1-4 Hour	15-17	2	0.09
10/05/2012	Friday	DA	1-4 Hour	16-17	2	0.09
10/17/2012	Wednesday	DA	1-4 Hour	15-18	2	0.09
10/18/2012	Thursday	DA	1-4 Hour	14-17	2	0.09
		DO	1-4 Hour	15-18	5	4.24
			2-6 Hour	14-19	1	7.48
10/29/2012	Monday	DA	1-4 Hour	19	2	0.09

4.2.2 Summary load impacts

Table 4–8 shows average hourly estimated *reference load*, *observed load*, *load impacts* and *percentage load impacts* for the DA and DO notice and associated product types, for each of SCE's CBP events, and for averages across each of the respective events. The average hourly DA load impact was 0.04 MW, while DO load impacts averaged 6.2 MW for the 1-4 Hour product, and 10.3 MW for the 2-6 Hour product. Average percentage load impacts were 20 and 18 percent for the two DO product types.

Table 4–8: Average Hourly Load Impacts by Event – *SCE CBP*

Event Date	Notice	Product	Number of Accounts	Average Customer Reference Load (kW)	Average Customer Load Impact (kW)	Aggregate Reference Load (MW)	Aggregate Load Impact (MW)	% Load Impact	Average Event Temp.	Nom. Capacity (MW)
07/20/2012	DO	1-4 Hour	204	168.9	25.4	34.5	5.2	15.0%	87.9	4.26
		2-6 Hour	198	282.5	51.0	55.9	10.1	18.1%	85.4	7.48
07/23/2012	DA	1-4 Hour	1	265.6	42.7	0.27	0.04	16.1%	96.7	0.08
07/24/2012	DA	1-4 Hour	1	287.7	92.1	0.29	0.09	32.0%	91.8	0.08
07/25/2012	DA	1-4 Hour	1	281.0	80.0	0.28	0.08	28.5%	86.3	0.08
07/30/2012	DA	1-4 Hour	1	218.3	60.6	0.22	0.06	27.8%	91.9	0.08
07/31/2012	DA	1-4 Hour	1	266.8	95.0	0.27	0.10	35.6%	95.9	0.08
08/07/2012	DO	1-4 Hour	160	195.1	38.3	31.2	6.1	19.6%	94.2	4.82
		2-6 Hour	198	291.2	52.8	57.7	10.5	18.1%	89.8	7.48
08/13/2012	DO	1-4 Hour	160	198.4	41.0	31.7	6.6	20.7%	95.8	4.82
		2-6 Hour	198	296.5	52.9	58.7	10.5	17.8%	90.4	7.48
08/14/2012	DO	1-4 Hour	160	192.7	42.1	30.8	6.7	21.9%	93.6	4.82
		2-6 Hour	198	291.6	55.9	57.7	11.1	19.2%	88.5	7.48
09/14/2012	DO	1-4 Hour	154	201.6	43.4	31.0	6.7	21.5%	97.8	4.42
		2-6 Hour	197	293.8	59.5	57.9	11.7	20.2%	94.8	7.48
10/01/2012	DA	1-4 Hour	3	637.0	-66.0	1.91	-0.20	-10.4%	86.8	0.09
10/02/2012	DA	1-4 Hour	3	696.7	-34.7	2.09	-0.10	-5.0%	81.4	0.09
	DO	1-4 Hour	147	197.6	42.2	29.0	6.2	21.3%	94.5	4.24
		2-6 Hour	197	284.8	48.7	56.1	9.6	17.1%	90.8	7.48
10/03/2012	DA	1-4 Hour	3	677.2	15.6	2.03	0.05	2.3%	74.3	0.09
10/05/2012	DA	1-4 Hour	3	526.2	-21.7	1.58	-0.06	-4.1%	71.9	0.09
10/17/2012	DA	1-4 Hour	3	610.9	22.5	1.83	0.07	3.7%	86.9	0.09
10/18/2012	DA	1-4 Hour	3	634.4	50.6	1.90	0.15	8.0%	75.7	0.09
	DO	1-4 Hour	147	174.4	38.9	25.6	5.7	22.3%	79.8	4.24
		2-6 Hour	197	269.7	44.2	53.1	8.7	16.4%	77.3	7.48
10/29/2012	DA	1-4 Hour	3	533.4	69.2	1.60	0.21	13.0%	68.8	0.09
Typical	DA	1-4 Hour	2	548.7	18.3	1.19	0.04	3.3%	79.5	0.08
	DO	1-4 Hour	162	189.0	38.2	30.6	6.2	20.2%	92.2	4.44
		2-6 Hour	198	287.2	52.2	56.7	10.3	18.2%	88.2	7.48

Table 4–9 shows the distribution of average hourly load impacts for the typical event, by industry type. In line with the number of nominated customers, DO load impacts are concentrated in the Retail Stores industry type.[8]

[8] The fractional numbers of customer accounts for DA occur due to averaging small numbers over events.

Table 4–9: Distribution of Average Hourly Load Impacts by Industry Type – SC*E CBP*

Notice	Industry	Accounts Called	Average Customer Reference Load (kW)	Average Customer Load Impact (kW)	Aggregate Reference Load (MW)	Aggregate Load Impact (MW)	% Load Impact	Average Event Temp.
DA	Agriculture, Mining & Construction	0.4	263.9	74.1	0.11	0.03	28.1%	92.5
	Manufacturing							
	Wholesale, Transport, other utilities							
	Retail stores							
	Offices, Hotels, Finance, Services	1.8	616.5	5.1	1.08	0.01	0.8%	78.6
	Schools							
	Institutional/Government							
	Other or unknown							
	Total DA	**2.2**	**548.7**	**18.3**	**1.19**	**0.04**	**3.3%**	**79.5**
DO	Agriculture, Mining & Construction	1	205.5	12.8	0.26	0.02	6.2%	96.3
	Manufacturing							
	Wholesale, Transport, other utilities	3	180.4	112.7	0.62	0.39	62.4%	97.5
	Retail stores	347	245.8	46.2	85.3	16.0	18.8%	89.6
	Offices, Hotels, Finance, Services	1	259.0	41.2	0.26	0.04	15.9%	97.1
	Schools							
	Institutional/Government	7	132.5	1.3	0.87	0.01	1.0%	84.2
	Other or unknown							
	Total DO	**359**	**243.0**	**45.9**	**87.3**	**16.5**	**18.9%**	**89.6**

Table 4–10 shows the distribution of average hourly load impacts by LCA. Most of the load impacts for both notice types occurred in the LA Basin.

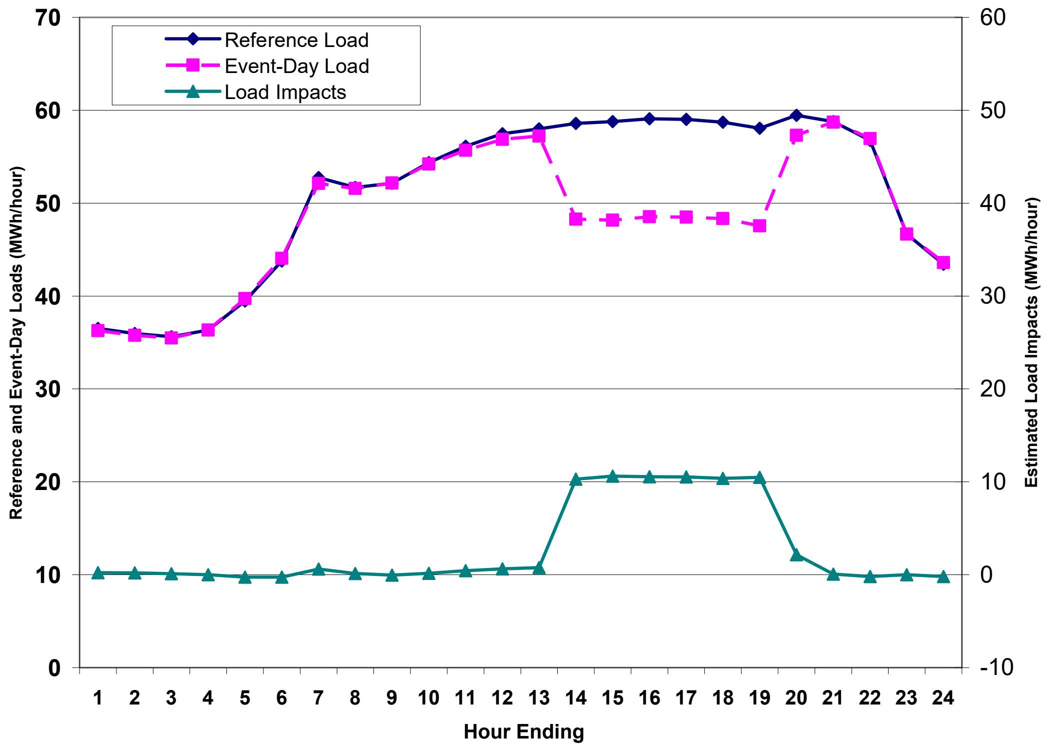
Table 4–10: Distribution of Average Hourly Load Impacts by LCA – *SCE CBP*

Notice	LCA	Accounts Called	Average Customer Reference Load (kW)	Average Customer Load Impact (kW)	Aggregate Reference Load (MW)	Aggregate Load Impact (MW)	% Load Impact	Average Event Temp.
DA	LA Basin	1.8	616.5	5.1	1.08	0.01	0.8%	78.6
	Outside LA							
	Ventura	0.4	263.9	74.1	0.11	0.03	28.1%	92.5
	Total DA	**2.2**	**548.7**	**18.3**	**1.19**	**0.04**	**3.3%**	**79.5**
DO	LA Basin	267	239.4	45.9	64.0	12.3	19.2%	89.7
	Outside LA	26	253.8	49.6	6.6	1.3	19.5%	95.3
	Ventura	66	253.2	44.3	16.7	2.9	17.5%	87.1
	Total DO	**359**	**243.0**	**45.9**	**87.3**	**16.5**	**18.9%**	**89.6**

4.2.3 Hourly load impacts

Figure 4–3 illustrates the hourly profiles of the estimated reference load, observed load, and estimated load impacts (in MW) of the SCE CBP DO 2-6 product type for the six-hour August 13 event, which was called from hours-ending 14 to 19.

Figure 4–3: Hourly Loads and Load Impacts – SCE CBP DO 2-6
August 13 Event



4.2.4 Load impacts of TA/TI and AutoDR participants

Table 4–11 shows average hourly load impacts for an average of 111 customer accounts that have participated in TA/TI. Their load impacts averaged 2.8 MW, and 19.4 percent of their reference load. This compares favorably to their approved load impacts of 2.5 MW.

Table 4–11: Load Impacts of TA/TI Participants – *SCE CBP*

Event Date	Number of SAIDs	Estimated Reference Load (kW)	Observed Load (kW)	Estimated Load Impact (kW)	% Load Impact	Approved Load Shed (kW)
7/20/2012	135	17,460	14,542	2,918	16.7%	2,576
8/7/2012	112	14,499	11,555	2,944	20.3%	2,537
8/13/2012	112	14,754	11,882	2,873	19.5%	2,537
8/14/2012	112	14,392	11,468	2,924	20.3%	2,537
9/14/2012	106	14,501	11,157	3,344	23.1%	2,484
10/2/2012	101	13,244	10,909	2,335	17.6%	2,424
10/18/2012	101	12,160	9,923	2,237	18.4%	2,424
Average	**111**	**14,430**	**11,634**	**2,797**	**19.4%**	**2,503**

Table 4–12 shows load impacts for AutoDR participants. On DO events, about 90 AutoDR participants provided 1.5 to 2 MW of load impacts, not far from their approved value.

Table 4–12: Load Impacts of AutoDR Participants – *SCE CBP*

Event Date	Number of SAIDs	Estimated Reference Load (kW)	Observed Load (kW)	Estimated Load Impact (kW)	% Load Impact	Approved Load Shed (kW)
7/20/2012	115	9,961	8,315	1,646	16.5%	2,882
8/7/2012	92	7,339	5,592	1,747	23.8%	2,170
8/13/2012	92	7,452	5,748	1,703	22.9%	2,170
8/14/2012	92	7,085	5,404	1,681	23.7%	2,170
9/14/2012	86	7,112	5,099	2,012	28.3%	2,046
10/1/2012	2	1,539	1,626	-87	-5.7%	139
10/2/2012	83	7,801	6,300	1,500	19.2%	2,056
10/3/2012	2	1,671	1,620	51	3.1%	139
10/5/2012	2	1,321	1,422	-101	-7.7%	139
10/17/2012	2	1,466	1,389	76	5.2%	139
10/18/2012	83	6,737	5,147	1,590	23.6%	2,056
10/29/2012	2	1,479	1,292	187	12.6%	139
Average	**54**	**5,080**	**4,080**	**1,001**	**19.7%**	**1,354**

4.3 Capacity Bidding Program (CBP) – SDG&E

4.3.1 Events for SDG&E CBP

Table 4–13 lists SDG&E's CBP events in 2012, which included six DA and five DO events.

Table 4–13: Event Summary for 2012 – *SDG&E CBP*

Date	Day of Week	Notice	Product	Hours Ending	Num. of Aggregators	Nom. Capacity (MW)
8/8/2012	Wednesday	DO	1-4 Hour	14-17	4	9.3
			2-6 Hour	14-17	1	2.4
8/9/2012	Thursday	DA	1-4 Hour	14-17	3	7.5
8/10/2012	Friday	DA	1-4 Hour	15-18	3	7.5
8/13/2012	Monday	DO	1-4 Hour	14-17	4	9.3
			2-6 Hour	14-17	1	2.4
8/14/2012	Tuesday	DA	1-4 Hour	15-18	3	7.5
9/13/2012	Thursday	DO	1-4 Hour	15-18	4	9.7
			2-6 Hour	15-18	1	2.4
9/14/2012	Friday	DA	1-4 Hour	15-18	3	7.2
		DO	1-4 Hour	15-18	4	9.7
			2-6 Hour	15-18	1	2.4
9/17/2012	Monday	DA	1-4 Hour	15-18	3	7.2
10/1/2012	Monday	DA	1-4 Hour	15-18	3	7.3
		DO	1-4 Hour	15-18	4	9.2
			2-6 Hour	15-18	1	2.4
10/2/2012	Tuesday	DA	1-4 Hour	15-18	3	7.3

4.3.2 Summary load impacts

Table 4–14 shows average hourly estimated *reference load*, *observed load*, *load impacts* and *percentage load impacts* for the DA and DO notice and associated product types, for each of SDG&E's CBP events, and for averages across each of the respective events. The average hourly DA load impact was 6.4 MW, while DO load impacts averaged 6.5 MW for the 1-4 Hour product, and 3.3 MW for the 2-6 Hour product. Average percentage load impacts were 25.5 percent for the DA product, and 13 to 15 percent for the two DO product types.

Table 4–14: Average Hourly Load Impacts by Event – *SDG&E CBP*

Event Date	Notice	Product	Number of Accounts	Average Customer Reference Load (kW)	Average Customer Load Impact (kW)	Aggregate Reference Load (MW)	Aggregate Load Impact (MW)	% Load Impact	Average Event Temp.	Nominated Capacity (MW)
8/8/2012	DO	1-4 Hour	241	205.4	30.9	49.5	7.45	15.1%	83.3	9.3
		2-6 Hour	77	292.5	46.0	22.5	3.55	15.7%	84.0	2.4
8/9/2012	DA	1-4 Hour	79	321.2	95.3	25.4	7.53	29.7%	81.1	7.5
8/10/2012	DA	1-4 Hour	79	311.2	96.4	24.6	7.62	31.0%	82.2	7.5
8/13/2012	DO	1-4 Hour	241	202.8	19.9	48.9	4.80	9.8%	86.4	9.3
		2-6 Hour	77	299.2	48.1	23.0	3.70	16.1%	87.2	2.4
8/14/2012	DA	1-4 Hour	79	339.3	95.0	26.8	7.51	28.0%	81.0	7.5
9/13/2012	DO	1-4 Hour	244	206.0	27.9	50.3	6.80	13.5%	77.3	9.7
		2-6 Hour	77	284.5	40.0	21.9	3.08	14.1%	77.8	2.4
9/14/2012	DA	1-4 Hour	78	330.1	73.4	25.7	5.73	22.2%	93.0	7.2
	DO	1-4 Hour	244	220.9	27.1	53.9	6.62	12.3%	94.7	9.7
		2-6 Hour	77	304.4	48.9	23.4	3.77	16.1%	95.5	2.4
9/17/2012	DA	1-4 Hour	78	328.1	100.9	25.6	7.87	30.8%	77.5	7.2
10/1/2012	DA	1-4 Hour	78	310.3	52.3	24.2	4.08	16.9%	82.5	7.3
	DO	1-4 Hour	249	213.6	27.8	53.2	6.93	13.0%	84.7	9.2
		2-6 Hour	77	284.0	29.7	21.9	2.29	10.5%	85.1	2.4
10/2/2012	DA	1-4 Hour	78	288.9	54.2	22.5	4.23	18.8%	84.4	7.3
Average	DA	1-4 Hour	78	318.5	81.2	25.0	6.37	25.5%	83.3	7.3
	DO	1-4 Hour	244	209.8	26.7	51.1	6.52	12.7%	85.5	9.4
		2-6 Hour	77	292.9	42.6	22.6	3.28	14.5%	86.0	2.4

Table 4–15 shows the distribution of average hourly load impacts for the average event by industry type. Most of the DA load impacts came from a small number of Manufacturing customer accounts, while the larger number of commercial building accounts produced 0.75 MW of load reductions. The majority of DO load impacts were provided by retail stores.

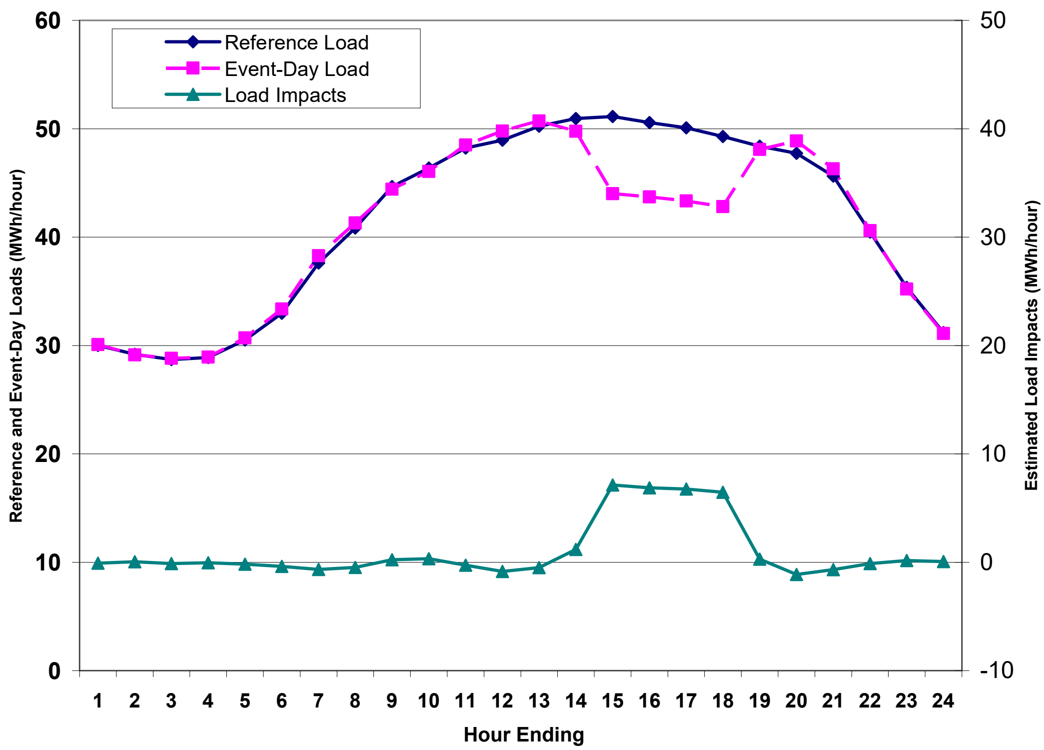
Table 4–15: Distribution of Average Hourly Load Impacts by Industry Type – *SDG&E CBP*

Notice	Industry	Accounts Called	Average Customer Reference Load (kW)	Average Customer Load Impact (kW)	Aggregate Reference Load (MW)	Aggregate Load Impact (MW)	% Load Impact	Average Event Temp.
DA	Agriculture, Mining & Construction							
	Manufacturing	4	1,422.1	1,204.2	5.69	4.82	84.7%	80.6
	Wholesale, Transport, other utilities	5	113.9	111.6	0.55	0.54	98.0%	92.4
	Retail stores	1	814.3	6.7	0.81	0.01	0.8%	85.3
	Offices, Hotels, Finance, Services	65	265.3	11.5	17.24	0.75	4.4%	83.1
	Schools							
	Institutional/Government	3	209.8	80.7	0.63	0.24	38.5%	92.6
	Other or unknown	1	86.0	14.6	0.09	0.01	17.0%	80.1
	Total DA	**79**	**317.2**	**80.8**	**25.01**	**6.37**	**25.5%**	**83.2**
DO	Agriculture, Mining & Construction							
	Manufacturing	10	297.9	32.5	2.98	0.32	10.9%	82.8
	Wholesale, Transport, other utilities	14	127.9	72.9	1.74	0.99	57.0%	83.3
	Retail stores	265	218.4	26.9	57.96	7.13	12.3%	85.8
	Offices, Hotels, Finance, Services	26	356.5	29.8	9.41	0.79	8.3%	85.9
	Schools							
	Institutional/Government	3	396.0	207.8	1.11	0.58	52.5%	84.2
	Other or unknown	3	194.4	-5.9	0.51	-0.02	-3.0%	79.4
	Total DO	**321**	**229.7**	**30.5**	**73.70**	**9.80**	**13.3%**	**85.6**

4.3.3 Hourly load impacts

Figure 4–4 illustrates the hourly profiles of the estimated reference load, observed load, and estimated load impacts (in MW) of the SDG&E DO 1-4 product type for the four-hour September 13 event, which was called for hours-ending 15-18.

Figure 4–4: Hourly Loads and Load Impacts – SDG&E CBP DO 1-4
September 13 Event



4.2.4 Load impacts of TA/TI and AutoDR participants

Tables 4–16 and 4–17 show load impacts for TA/TI participants in SDG&E's CBP DA and DO programs, respectively. Two customers with day-ahead notice were on TA/TI. They provided an average of 103 kW in load impacts across seven event days. For CBP DO, approximately 59 TA/TI customer accounts provided an average of 1.4 MW of load impacts across five event days, compared to an average approved level of 1.7 MW.

Table 4–16: Load Impacts of TA/TI Participants – *SDG&E CBP DA*

Event Date	Number of SAIDs	Estimated Reference Load (kW)	Observed Load (kW)	Estimated Load Impact (kW)	% Load Impact	Approved Load Shed (kW)
8/9/2012	2	1,160	1,092	68	5.8%	105
8/10/2012	2	1,149	1,094	54	4.7%	105
8/14/2012	2	1,297	1,086	210	16.2%	105
9/14/2012	2	1,267	1,131	136	10.7%	105
9/17/2012	2	1,264	1,243	21	1.7%	105
10/1/2012	2	1,323	1,126	198	14.9%	105
10/2/2012	2	1,193	1,157	36	3.0%	105
Average	**2**	**1,236**	**1,133**	**103**	**8.4%**	**105**

Table 4–17: Load Impacts of TA/TI Participants – *SDG&E CBP DO*

Event Date	Number of SAIDs	Estimated Reference Load (kW)	Observed Load (kW)	Estimated Load Impact (kW)	% Load Impact	Approved Load Shed (kW)
8/8/2012	58	18,694	17,229	1,465	7.8%	1,554
8/13/2012	58	19,344	18,030	1,314	6.8%	1,554
9/13/2012	59	20,312	19,011	1,300	6.4%	1,769
9/14/2012	59	21,892	19,946	1,946	8.9%	1,769
10/1/2012	59	20,180	19,344	836	4.1%	1,766
Average	**59**	**20,084**	**18,712**	**1,372**	**6.8%**	**1,683**

Table 4–18 shows that an average of 22 AutoDR customer accounts provided 0.35 MW of load impacts, compared to approved levels of 1.5 MW. All of SDG&E's AutoDR customers received day-of notice of events.

Table 4–18: Load Impacts of AutoDR Participants – *SDG&E CBP DO*

Event Date	Number of SAIDs	Estimated Reference Load (kW)	Observed Load (kW)	Estimated Load Impact (kW)	% Load Impact	Approved Load Shed (kW)
8/8/2012	20	5,019	4,835	184	3.7%	1,335
8/13/2012	20	5,143	5,070	73	1.4%	1,335
9/13/2012	24	7,577	7,136	440	5.8%	1,699
9/14/2012	24	8,444	7,770	674	8.0%	1,699
10/1/2012	23	7,495	7,104	392	5.2%	1,659
Average	**22**	**6,736**	**6,383**	**353**	**5.2%**	**1,545**

4.4 Comparison to CBP Load Impacts from Previous Years

To asses the extent to which CBP load impacts have varied over recent years, Table 4–19 compares nominations, estimated per-customer load impacts, and aggregate load impacts for CBP DA and DO at each of the three utilities for 2010 and 2011, as well as the current study for 2012.[9] Changes in load impacts over time can result from a number of factors, including potential changes in the number of aggregator contracts, customer enrollments and nominations, and differences in the types of events called and weather conditions. Without detailed examination of those factors, a review of the values shows that most aggregate load impacts have remained reasonably stable over the past three years, and a few have increased. The notable difference between SCE CBP DA load impacts in 2011 compared to the other two years appears to be due to a substantially larger number of nominated customers in 2011.

Table 4–19: Average Hourly CBP Aggregate Load Impacts – *2010 - 2012*

Utility	Year	Nominated Accounts		Per-Customer Load Impacts (kW)		Aggregate Load Impacts (MW)	
		DA	DO	DA	DO	DA	DO
PG&E	2012	166	370	122.9	62.8	20.4	23.3
	2011	150	219	90.7	79.5	13.6	17.4
	2010	370	355	31.9	78.6	11.8	27.9
SCE	2012	4	399	9.9	41.3	0.04	16.5
	2011	91	412	42.9	45.9	3.90	18.9
	2010	78	336	10.3	45.8	0.80	15.4
SDG&E	2012	79	321	80.7	30.5	6.4	9.8
	2011	48	318	235.4	34.6	11.3	11.0
	2010	112	269	85.7	32.3	9.6	8.7

[9] The 2010 evaluation was conducted by CA Energy Consulting, while the 2011 evaluation was conducted by Freeman, Sullivan & Co.

5. STUDY RESULTS – *EX POST* LOAD IMPACTS FOR AMP AND DRC

This section summarizes *ex post* load impacts for the PG&E and SCE contract-based aggregator programs, AMP and DRC respectively.

5.1 PG&E Aggregator Managed Portfolio (AMP)

5.1.1 Event Characteristics for PG&E AMP

Table 5–1 summarizes features of the three AMP DA and DO events in 2012.

Table 5–1: Event Summary for 2012 – *PG&E AMP*

Date	Day of Week	Notice	Product	Hours Ending	Num. of Aggregators	Nom. Capacity (MW)
07/11/12	Wednesday	DA	1-4 Hour	15 - 18	1	44.0
		DO	2-5 Hour	16 - 19	1	22.0
			2-6 Hour	16 - 19	2	119.5
08/09/12	Thursday	DA	1-4 Hour	16 - 19	1	44.0
		DO	2-5 Hour	15 - 18	1	22.0
			2-6 Hour	16 - 19	2	119.5
08/10/12	Friday	DA	1-4 Hour	16 - 19	1	44.0
		DO	2-5 Hour	15 - 18	1	22.0
			2-6 Hour	16 - 19	2	119.5

5.1.2 Summary load impacts

Table 5–2 shows average hourly estimated *reference load*, *observed load*, *load impacts* and *percentage load impacts* for the DA and DO notice and associated product types, for each of PG&E's AMP events, and for averages across each of the respective events. The average hourly DA load impact was 50 MW, while DO load impacts averaged 21.5 MW for the 2-5 Hour product, and 107.6 MW for the 2-6 Hour product. These load impacts represented nearly 40 percent of the reference load for the DA product, and about 28 percent for the two DO product types.

Table 5–2: Average Hourly Load Impacts by Event – *PG&E AMP*

Event Date	Notice	Product	Number of Accounts	Average Customer Reference Load (kW)	Average Customer Load Impact (kW)	Aggregate Reference Load (MW)	Aggregate Load Impact (MW)	% Load Impact	Average Event Temp.	Nom. Capacity (MW)
07/11/12	DA	1-4 Hour	234	541.4	232.0	126.7	54.3	42.9%	94.8	44.0
	DO	2-5 Hour	143	516.6	142.6	73.9	20.4	27.6%	85.2	22.0
		2-6 Hour	964	411.8	114.6	397.0	110.4	27.8%	90.0	119.5
08/09/12	DA	1-4 Hour	232	566.5	224.1	131.4	52.0	39.6%	95.1	44.0
	DO	2-5 Hour	149	515.8	152.7	76.9	22.7	29.6%	85.1	22.0
		2-6 Hour	985	397.1	110.3	391.1	108.7	27.8%	89.7	119.5
08/10/12	DA	1-4 Hour	232	540.7	187.1	125.4	43.4	34.6%	95.0	44.0
	DO	2-5 Hour	149	486.9	142.4	72.5	21.2	29.3%	81.5	22.0
		2-6 Hour	985	390.7	105.3	384.9	103.7	26.9%	89.7	119.5
Average	DA	1-4 Hour	233	549.5	214.5	127.9	49.9	39.0%	95.0	44.0
	DO	2-5 Hour	147	506.3	145.9	74.4	21.5	28.8%	84.0	22.0
		2-6 Hour	978	399.8	110.0	391.0	107.6	27.5%	89.8	119.5

Table 5–3 shows the distribution of average hourly load impacts for the average AMP DA and DO event by industry type. DA load impacts were concentrated largely in the Manufacturing industry type. DO load impacts were spread across several industry types.

Table 5–3: Distribution of Average Hourly Load Impacts by Industry Type – *PG&E AMP*

Notice	Industry	Accounts Called	Average Customer Reference Load (kW)	Average Customer Load Impact (kW)	Aggregate Reference Load (MW)	Aggregate Load Impact (MW)	% Load Impact	Average Event Temp.
DA	Agriculture, Mining & Construction	33	55.5	30.4	1.8	1.0	54.8%	93.4
	Manufacturing	95	888.2	348.9	84.4	33.1	39.3%	96.6
	Wholesale, Transport, other utilities	16	346.6	75.8	5.7	1.2	21.9%	94.5
	Retail stores	29	414.0	68.1	12.0	2.0	16.5%	94.7
	Offices, Hotels, Finance, Services	17	430.3	148.7	7.5	2.6	34.5%	81.3
	Schools	31	256.7	76.6	8.0	2.4	29.8%	92.3
	Institutional/Government	11	776.6	688.1	8.5	7.6	88.6%	101.0
	Other or unknown	0	0.0	0.0	0.0	0.0		
	Total DA	**233**	**549.4**	**214.4**	**127.8**	**49.9**	**39.0%**	**95.0**
DO	Agriculture, Mining & Construction	279	293.0	153.1	81.8	42.7	52.2%	88.0
	Manufacturing	134	787.3	178.0	105.5	23.9	22.6%	96.2
	Wholesale, Transport, other utilities	140	517.2	236.2	72.2	33.0	45.7%	102.0
	Retail stores	260	234.5	19.8	61.0	5.2	8.5%	94.6
	Offices, Hotels, Finance, Services	218	453.3	73.5	99.0	16.1	16.2%	77.7
	Schools	41	348.6	75.5	14.2	3.1	21.7%	86.5
	Institutional/Government	53	597.2	96.2	31.6	5.1	16.1%	73.4
	Other or unknown	10	197.4	65.1	2.0	0.7	33.0%	75.5
	Total DO	**1,135**	**411.8**	**114.2**	**467.2**	**129.6**	**27.7%**	**88.9**

Table 5–4 shows the distribution of AMP average hourly load impacts by LCA. The majority of DA load impacts occurred outside of any of the LCAs, while DO load impacts were spread across a number of LCAs.

Table 5–4: Distribution of Average Hourly Load Impacts by LCA – *PG&E AMP*

Notice	LCA	Accounts Called	Average Customer Reference Load (kW)	Average Customer Load Impact (kW)	Aggregate Reference Load (MW)	Aggregate Load Impact (MW)	% Load Impact	Average Event Temp.
DA	Greater Bay Area	65	510.4	88.9	33.2	5.8	17.4%	82.1
	Greater Fresno	28	537.1	273.3	15.2	7.7	50.9%	106.0
	Humboldt	0	0.0	0.0	0.0	0.0		
	Kern	2	530.7	117.2	1.1	0.2	22.1%	103.9
	Northern Coast	20	256.5	102.4	5.1	2.0	39.9%	92.0
	Not in any LCA	81	805.5	387.6	65.5	31.5	48.1%	102.1
	Sierra	23	151.0	21.7	3.5	0.5	14.4%	101.7
	Stockton	13	327.9	157.7	4.3	2.1	48.1%	100.8
	Total DA	**233**	**549.4**	**214.4**	**127.8**	**49.9**	**39.0%**	**95.0**
DO	Greater Bay Area	400	353.7	39.0	141.6	15.6	11.0%	79.6
	Greater Fresno	225	313.9	144.8	70.5	32.5	46.1%	106.0
	Humboldt	8	166.2	126.0	1.3	1.0	75.8%	60.0
	Kern	144	384.4	225.6	55.2	32.4	58.7%	104.0
	Northern Coast	55	307.3	78.8	16.9	4.3	25.6%	89.2
	Not in any LCA	206	736.4	156.1	151.7	32.1	21.2%	88.7
	Sierra	24	470.7	214.6	11.3	5.2	45.6%	100.8
	Stockton	73	255.8	87.3	18.7	6.4	34.1%	100.5
	Total DO	**1,135**	**411.8**	**114.2**	**467.2**	**129.6**	**27.7%**	**88.9**

5.1.3 Hourly load impacts

Figures 5–1 and 5–2 illustrate the hourly profiles of the estimated reference load, observed load and estimated load impacts (in MW) of the PG&E AMP DA 1-4 and DO 2-6 product types for the four-hour August 9 event, which was called for hours-ending 16 through19.

Figure 5–1: Hourly Loads and Load Impacts – PG&E AMP DA 1-4
August 9 Event

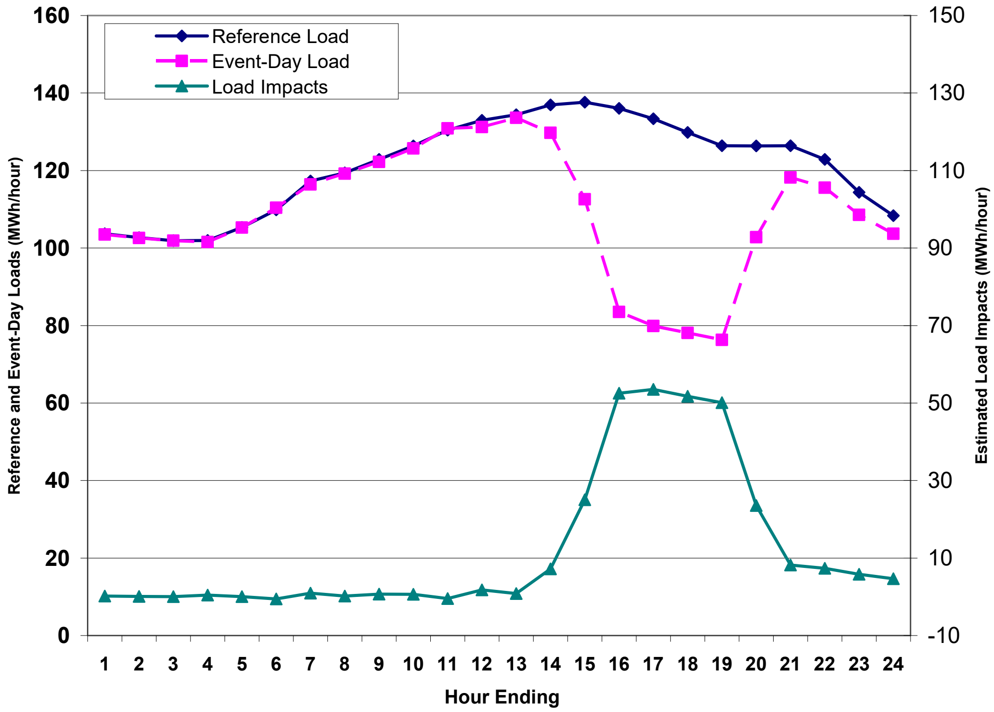
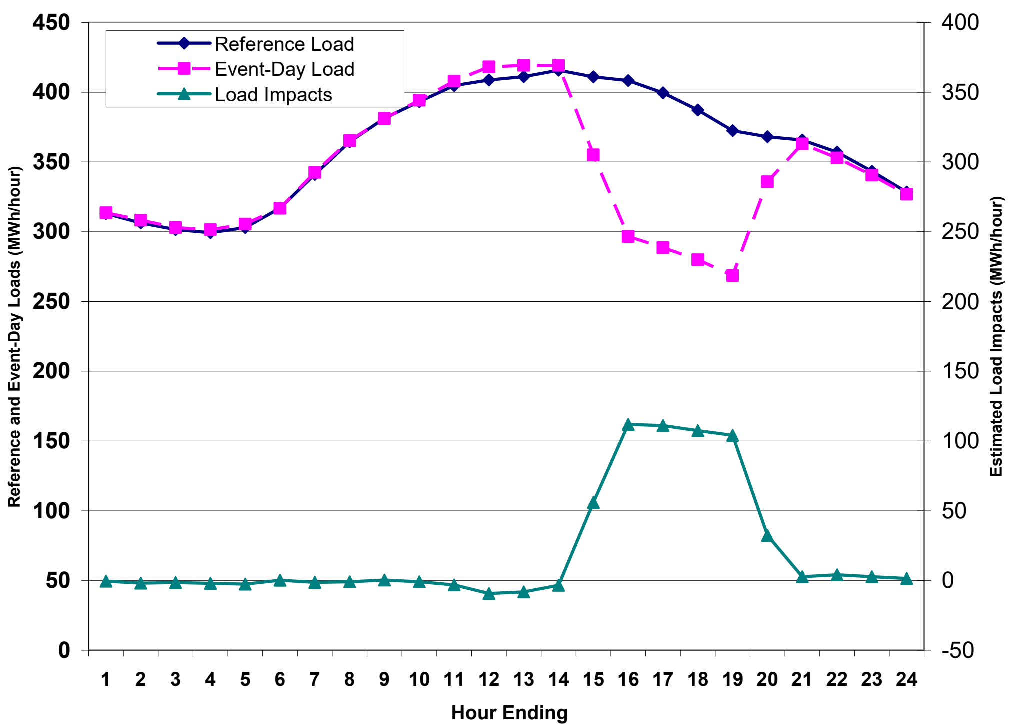


Figure 5–2: Hourly Loads and Load Impacts – PG&E AMP DO 2-6
August 9 Event



5.1.4 Load impacts of TA/TI and AutoDR participants

Table 5–5 shows load impacts for TA/TI participants in AMP. An average of 51 TA/TI customer accounts provided an average of 9.9 MW of load impacts, compared to an approved load shed level of 18.8 MW.

Table 5–5: Load Impacts of TA/TI Participants – *PG&E AMP*

Event Date	Number of SAIDs	Estimated Reference Load (kW)	Observed Load (kW)	Estimated Load Impact (kW)	% Load Impact	Approved Load Shed (kW)
7/11/2012	49	38,227	28,929	9,297	24.3%	17,765
8/9/2012	52	44,696	34,502	10,194	22.8%	19,360
8/10/2012	52	43,791	33,657	10,134	23.1%	19,360
Average	**51**	**42,238**	**32,363**	**9,875**	**23.4%**	**18,828**

As shown in Table 5–6, four AutoDR customer accounts provided 0.23 MW of load impacts, compared to 1.2 MW of approved levels.

Table 5–6: Load Impacts of AutoDR Participants – *PG&E AMP*

Event Date	Number of SAIDs	Estimated Reference Load (kW)	Observed Load (kW)	Estimated Load Impact (kW)	% Load Impact	Approved Load Shed (kW)
7/11/2012	5	5,964	5,602	362	6.1%	1,211
8/9/2012	4	3,668	3,423	245	6.7%	1,163
8/10/2012	4	3,668	3,598	70	1.9%	1,163
Average	**4**	**4,433**	**4,208**	**226**	**5.1%**	**1,179**

5.2 SCE's Demand Response Resource Contracts (DRC)

5.2.1 Event Characteristics for SCE DRC

Table 5–7 summarizes features of SCE DRC events in 2012. One DA event and two DO events were called, one of which was a partial event.

Table 5–7: Event Summary for 2012 – *SCE DRC*

Date	Day of Week	Notice	Product	Hours Ending	Num. of Aggregators	Nom. Capacity (MW)
8/14/2012	Tuesday	DA		16-17	1	50
		DO		16-17	3	225
10/02/2012	Tuesday	DO		15-17	2	185

5.2.2 Summary load impacts

Table 5–8 shows average hourly estimated *reference load*, *observed load*, *load impacts* and *percentage load impacts* for the DA and DO product types, for the two SCE DRC events, and for the typical event, which is defined as the first event, in which all aggregators were called. The average hourly DA load impact was 21.8 MW, while the average hourly DO load impact was 160 MW. Average percentage load impacts were 66 percent for the DA product, and 29 percent for the DO product.

Table 5–8: Average Hourly Load Impacts by Event – *SCE DRC*

Event Date	Notice	Product	Number of Accounts	Average Customer Reference Load (kW)	Average Customer Load Impact (kW)	Aggregate Reference Load (MW)	Aggregate Load Impact (MW)	% Load Impact	Average Event Temp.	Nom. Capacity (MW)
8/14/2012	DA		142	233.4	153.5	33.1	21.8	65.8%	90.6	50
	DO		1648	334.1	97.2	550.6	160.1	29.1%	91.4	225
10/02/2012	DO		1213	323.6	95.3	392.6	115.5	29.4%	91.8	185
Typical	DA		142	233.4	153.5	33.1	21.8	65.8%	90.6	50
	DO		1648	334.1	97.2	550.6	160.1	29.1%	91.4	225

Table 5–9 shows the distribution of average hourly load impacts for the typical event by industry type. The majority of DA load impacts came from the Manufacturing industry type, while DO load impacts were spread across a range of industry types, topped by the Wholesale, Transport, and other utilities industry type.

Table 5–9: Distribution of Average Hourly Load Impacts by Industry Type – *SCE DRC*

Notice	Industry	Accounts Called	Average Customer Reference Load (kW)	Average Customer Load Impact (kW)	Aggregate Reference Load (MW)	Aggregate Load Impact (MW)	% Load Impact	Average Event Temp.
DA	Agriculture, Mining & Construction	85	65.4	63.8	5.6	5.4	97.6%	102.3
	Manufacturing	15	1381.4	849.1	20.7	12.7	61.5%	96.9
	Wholesale, Transport, other utilities	26	114.1	106.3	3.0	2.8	93.1%	88.9
	Retail stores	0						
	Offices, Hotels, Finance, Services	11	322.9	54.1	3.6	0.6	16.8%	73.4
	Schools	0						
	Institutional/Government	1	104.4	83.9	0.1	0.1	80.3%	69.8
	Other or unknown	4	60.2	48.6	0.2	0.2	80.8%	99.5
	Total DA	**142**	**233.4**	**153.5**	**33.1**	**21.8**	**65.8%**	**90.6**
DO	Agriculture, Mining & Construction	98	179.8	123.4	17.6	12.1	68.6%	96.7
	Manufacturing	128	724.4	172.2	92.7	22.0	23.8%	92.7
	Wholesale, Transport, other utilities	485	233.2	147.4	113.1	71.5	63.2%	91.6
	Retail stores	709	280.1	36.0	198.6	25.5	12.9%	92.7
	Offices, Hotels, Finance, Services	169	413.3	76.5	69.8	12.9	18.5%	89.7
	Schools	27	1658.0	213.1	44.8	5.8	12.9%	86.0
	Institutional/Government	32	435.3	321.4	13.9	10.3	73.8%	86.3
	Other or unknown	0						
	Total DO	**1,648**	**334.1**	**97.2**	**550.6**	**160.1**	**29.1%**	**91.5**

Table 5–10 shows the distribution of average hourly load impacts by LCA, most of which occurred in the LA Basin for both DA and DO.

Table 5–10: Distribution of Average Hourly Load Impacts by LCA – *SCE DRC*

Notice	LCA	Accounts Called	Average Customer Reference Load (kW)	Average Customer Load Impact (kW)	Aggregate Reference Load (MW)	Aggregate Load Impact (MW)	% Load Impact	Average Event Temp.
DA	LA Basin	51	502.8	293.9	25.6	15.0	58.5%	91.2
	Outside LA	6	97.8	97.8	0.6	0.6	100.0%	102.3
	Ventura	85	81.4	73.2	6.9	6.2	90.0%	81.7
	Total DA	**142**	**233.4**	**153.5**	**33.1**	**21.8**	**65.8%**	**90.6**
DO	LA Basin	1,285	344.1	102.6	442.1	131.8	29.8%	91.8
	Outside LA	146	239.4	95.1	34.9	13.9	39.7%	100.6
	Ventura	217	338.7	66.5	73.5	14.4	19.6%	86.7
	Total DO	**1,648**	**334.1**	**97.2**	**550.6**	**160.1**	**29.1%**	**91.5**

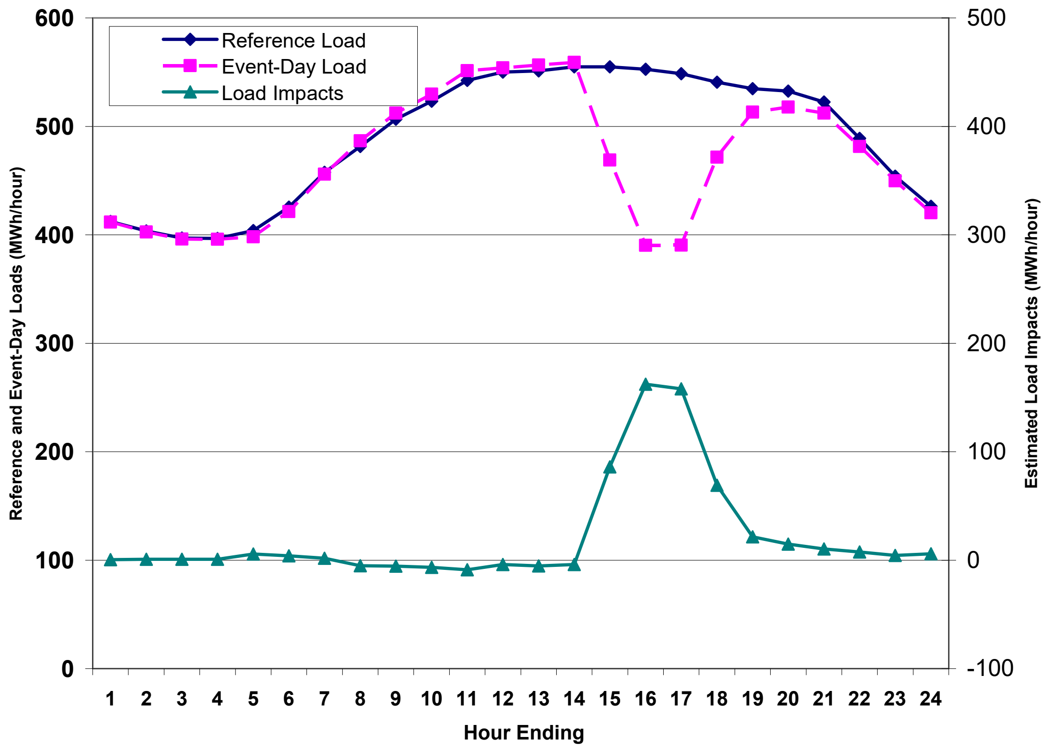
5.2.3 Hourly load impacts

Figures 5–3 and 5–4 illustrate the hourly profiles of the estimated reference load, observed load and estimated load impacts (in MW) of the SCE DRC DA and DO product types for the two-hour August 14 event, which was called for hours-ending 16-17.

Figure 5–3: Hourly Loads and Load Impacts – SCE DRC DA Typical Event

Figure removed due to confidentiality.

Figure 5–4: Hourly Loads and Load Impacts – SCE DRC DO
August 14 Event



5.2.4 Load impacts of TA/TI and AutoDR participants

Table 5–11 shows load impacts for TA/TI participants in DRC. The August 14 event provides the most representative information, as all aggregators were called. For that event, 241 TA/TI customer accounts provided 17 MW of load impacts (20 percent of their reference load), compared to an approved load shed level of 18.9 MW.

Table 5–11: Load Impacts of TA/TI Participants – *SCE DRC*

Event Date	Number of SAIDs	Estimated Reference Load (kW)	Observed Load (kW)	Estimated Load Impact (kW)	% Load Impact	Approved Load Shed (kW)
8/14/2012	241	84,472	67,505	16,967	20.1%	18,868
10/2/2012	177	54,759	43,561	11,197	20.4%	12,723
Average	**209**	**69,615**	**55,533**	**14,082**	**20.2%**	**15,795**

Table 5–12 shows results for AutoDR participants. For the August 14 event, 165 AutoDR participants provided 10.2 MW, or 20 percent of the reference load, compared to the approved level of 21 MW.

Table 5–12: Load Impacts of AutoDR Participants – *SCE DRC*

Event Date	Number of SAIDs	Estimated Reference Load (kW)	Observed Load (kW)	Estimated Load Impact (kW)	% Load Impact	Approved Load Shed (kW)
8/14/2012	165	50,226	40,002	10,224	20.4%	21,084
10/2/2012	43	12,963	8,651	4,312	33.3%	9,892
Average	**104**	**31,594**	**24,326**	**7,268**	**23.0%**	**15,488**

5.3 Comparison to Load Impacts from Previous Years

Table 5–13 compares nominations, estimated per-customer load impacts, and aggregate load impacts for the DA and DO versions of AMP and DRC for the years 2010 through 2012. Similarly to the CBP programs, aggregate load impacts have been relatively stable over the past three years, but with a substantial increase in 2012 for SCE DRC DO and some increases in DRC DA. Results for AMP DA could not be reported for 2010 due to confidentiality restrictions.

Table 5–13: Average Hourly Load Impacts for AMP and DRC – *2010 - 2012*

Utility	Year	Nominated Accounts		Per-Customer Load Impacts (kW)		Aggregate Load Impacts (MW)	
		DA	DO	DA	DO	DA	DO
PG&E (AMP)	2012	233	1,125	214.1	115.2	49.9	129.6
	2011	249	1,069	212.0	131.4	52.8	140.5
	2010	266	501	n/a	209.4	n/a	104.9
SCE (DRC)	2012	153	1,650	142.5	97.0	21.8	160.1
	2011	275	1,298	63.3	88.4	17.4	114.7
	2010	139	938	62.6	120.8	8.7	113.3

6. *EX ANTE* LOAD IMPACT FORECASTS

6.1 *Ex ante* Load Impact Requirements

The DR Load Impact Evaluation Protocols require that hourly load impact forecasts for event-based DR resources must be reported at the program level and by LCA for the following scenarios:

- For a typical event day in each year; and
- For the monthly system peak load day in each month for which the resource is available;

under both:

- 1-in-2 weather-year conditions, and
- 1-in-10 weather-year conditions.

at both:

- the program level (*i.e.*, in which only the program in question is called), and
- the portfolio level (*i.e.*, in which all demand response programs are called).

For the aggregator programs, there is no difference between the program- and portfolio-level load impacts

6.2 Description of Methods

This section describes the methods used to develop the relevant groups of customers, to develop reference loads for the relevant customer types and event day-types, and to develop load impacts for a typical event day.

6.2.1 Development of Customer Groups

For PG&E's program, customer accounts were assigned to one of three size groups and the relevant LCA. The three size groups were the following:

- Small – maximum demand less than 20 kW;
- Medium – maximum demand between 20 and 200 kW;
- Large – maximum demand greater than 200 kW.

The specific definition of "maximum demand" was based on the tariff on which the maximum monthly demand during the most recent twelve months. For example, a large customer has maximum monthly demand equal or exceed 200 kW for 3 consecutive months during the past twelve months. The total number of customer "cells" developed is therefore equal to 24 (= 3 size groups x 8 LCAs).

Neither SCE nor SDG&E differentiated their enrollment forecasts by size groups. Therefore, customers within each program were divided into groups according to notice level and LCA.

6.2.2 Development of Reference Loads and Load Impacts

Reference loads and load impacts for all of the above factors were developed in the following series of steps:

1. Define data sources;
2. Estimate *ex ante* regressions and simulate reference loads by service account and scenario;
3. Calculate percentage load impacts from *ex post* results;
4. Apply percentage load impacts to the reference loads; and
5. Scale the reference loads using enrollment forecasts.

Each of these steps is described below.

Define data sources
For all three utilities and all program types, the reference loads are developed using data for customers enrolled during the 2012 program year. The percentage load impacts are developed using the estimated *ex post* load impacts for the same customers, using event-specific data for program years 2010 and 2012.

Simulate reference loads
In order to develop reference loads, we first re-estimated regression equations as described below, for each enrolled customer account, using data for the current program year. The resulting estimates were used to simulate reference loads for each service account under the various scenarios required by the Protocols (*e.g.*, the typical event day in a 1-in-2 weather year).

The re-estimated regression equations were similar in design to the *ex post* load impact equations described in Section 3.2, differing in two ways. First, the *ex ante* models excluded the morning-usage variables. While these variables are useful for improving accuracy in estimating *ex post* load impacts for particular events, they complicate the use of the equations in *ex ante* simulation. That is, they would require a separate simulation of the level of the morning load. The second difference between the *ex post* and *ex ante* models is that the *ex ante* models use CDH60 as the weather variables in place of the weather variables used in the *ex post* regressions. The primary reason for this is that *ex ante* weather days were selected based on current-day temperatures, not factoring in lagged values. Therefore, we determined that this method is the most consistent way of reflecting the 1-in-2 and 1-in-10 weather conditions.

Once these models were estimated, we simulated 24-hour load profiles for each required scenario. The typical event day was assumed to occur in August. Most of the differences across scenarios can be attributed to varying weather conditions. The definitions of the 1-in-2 and 1-in-10 weather years, developed following PY2009, are the same as those used to develop *ex ante* load forecasts in previous studies.

Calculate forecast percentage load impacts
For each utility and program type, the percentage load impacts were based on the *ex post* load impacts for each event during the 2010 and 2012 program years. Specifically, we examined only customers enrolled in PY2012, but included available data from the 2010 program year for customers that were also enrolled in that year. This method allowed us to base the *ex ante* load impacts on a larger sample of events, which should improve the reliability and consistency of the load impacts across forecasts.

For each service account, we collect the hourly *ex post* load impact estimates and observed loads for every event available from PY10 and PY12. Within service account, we calculate the average and standard deviation of the load impact across the event days for three hour types: event hours, hours adjacent to events, and all other hours. These values are applied to the simulated reference loads to develop each customer's hourly load impact forecast.

For any given sub-group of customers (*e.g.*, CBP day-of customers over 200 kW in size in the Greater Bay Area), we sum the observed loads, hourly load impacts and their variances across the applicable service accounts for reporting purposes.

We calculate percentages by the three hour types in order to "standardize" the load impacts for application to the *ex ante* forecast event window (1:00 to 6:00 p.m. in April through October). That is, it allows us to control for the fact that the historical (*i.e.*, *ex post*) event hours can differ across customers and event days, and generally differ from the *ex ante* event window. The use of the load impacts by hour type allows us to simulate load impacts as though all customers (within a program and notice level) are called for the same event window.

The uncertainty-adjusted load impacts (*i.e.*, the 10^{th}, 30^{th}, 50^{th}, 70^{th}, and 90^{th} percentile scenarios of load impacts) are based on the variability of each customer's response across event days. That is, we calculate the standard deviation of each customer's percentage load impact across the available event days. The square of this (*i.e.*, the variance) is added across customers within each required subgroup. Each uncertainty-adjusted scenario was then calculated under the assumption that the load impacts are normally distributed with a mean equal to the total estimated load impact and a variance based on the variability of load impacts across event days.

Apply percentage load impacts to reference loads for each event scenario. In this step, the percentage load impacts were applied to the reference loads for each scenario to produce all of the required reference loads, estimated event-day loads, and scenarios of load impacts.

Apply forecast enrollments to produce program-level load impacts. The utilities provided enrollment forecasts. PG&E provided monthly enrollments through 2023 by program and notice level, with separate enrollments provided by LCA and size group.[10] SCE provided monthly enrollments for 2013, 2014, and 2015 through 2023 (under the assumption that enrollments remain fixed during that time period). SDG&E indicated that it expects enrollments to remain constant during the forecast period. The enrollments are then used to scale up the reference loads and load impacts for each required scenario and customer subgroup.

6.2.3 Reporting ex ante results

The next five sub-sections report *ex ante* load impacts for the aggregator programs sponsored by PG&E (CBP and AMP), SCE (CBP and DRC), and SDG&E (CBP) respectively. For each utility program and notice type (DA and DO), we provide summary information on nomination forecasts[11]; the level of load impacts across years; hourly profiles of reference loads and load impacts for typical event days; the distribution of load impacts by local capacity area; and comparisons to previous *ex ante* load impacts.

Together, these summaries provide useful indicators of the anticipated changes in the forecasted load impacts across the various scenarios represented in the Protocol tables. All of the tables required by the Protocols are provided in Appendices.

6.3 *Ex ante* Load Impacts for PG&E's CBP Program

6.3.1 Enrollment and load impact summary

Table 6–1 summarizes nominations and aggregate load impacts (MW) for CBP DA and DO across the *ex ante* time horizon. PG&E forecasts CBP nominations to increase by an annual rate of about 3 percent. By 2023, more than 200 DA customer accounts are expected to be nominated, while nearly 500 DO customer accounts will be nominated. DA load impacts are anticipated to rise from about 20 MW to nearly 26 MW, at 39 percent of the reference load, while DO load impacts rise from 29 MW to 38 MW, at 26 percent of the reference load.

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[10] PG&E also forecasts separate enrollments for program- and portfolio-level scenarios, where the portfolio-level enrollments account for the effects of dual enrollments. However, because AMP and CBP are capacity-based programs, the program- and portfolio-based load impacts are the same.

[11] For the aggregator programs, nominations are used in place of enrollments, since only nominated customers provide load impacts.

Table 6–1: Customer Nominations and *Ex ante* Load Impacts for August in a 1-in-2 Weather Year *PG&E CBP DA and DO*

Year	Day-Ahead				Day-Of			
	Nom. Cust. Accnts.	Load Impact (MW)	Ref. Load (MW)	% Load Impact	Nom. Cust. Accnts.	Load Impact (MW)	Ref. Load (MW)	% Load Impact
2013	168	19.6	50.7	38.7%	374	28.9	111.2	26.0%
2014	173	20.2	52.1	38.7%	383	29.7	114.2	26.0%
2015	177	20.7	53.5	38.7%	394	30.5	117.3	26.0%
2016	182	21.2	54.9	38.7%	404	31.3	120.4	26.0%
2017	187	21.8	56.4	38.7%	415	32.1	123.6	26.0%
2018	192	22.4	57.9	38.7%	426	33.0	126.9	26.0%
2019	197	23.0	59.4	38.7%	438	33.8	130.3	26.0%
2020	202	23.6	61.0	38.7%	449	34.7	133.8	26.0%
2021	208	24.2	62.7	38.7%	461	35.7	137.4	26.0%
2022	213	24.9	64.3	38.7%	474	36.6	141.0	26.0%
2023	219	25.6	66.1	38.7%	486	37.6	144.8	26.0%

Table 6–2 reports forecasts of average hourly load impacts for PGE's CBP DA and DO in 2013 and 2023, for an August peak day in 1-in-2 and 1-in-10 weather years.[12] Both notice types are expected to grow modestly over the forecast period.

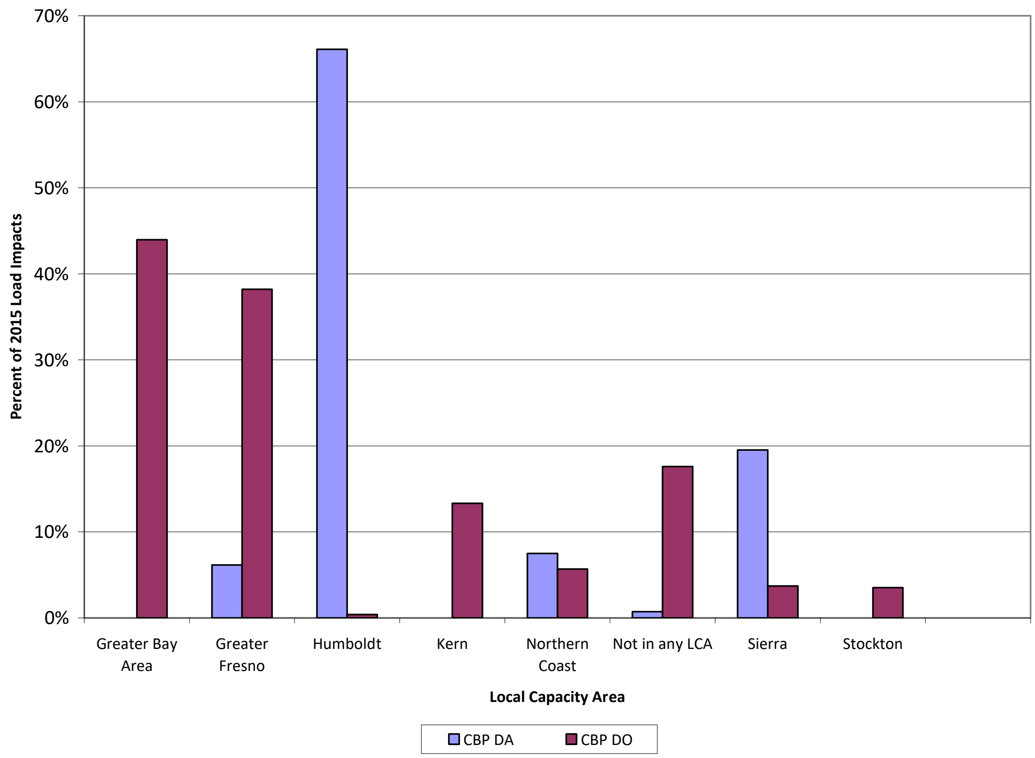
Table 6–2: Average Hourly Load Impacts for an August Peak Day in 1-in-2 and 1-in-10 Weather Years (2013 – 2023) – *PG&E CBP DA and DO*

Year	Day-Ahead		Day-Of	
	1-in-2	1-in-10	1-in-2	1-in-10
2013	19.6	21.0	28.9	28.5
2014	20.2	21.6	29.7	29.2
2015	20.7	22.1	30.5	30.0
2016	21.2	22.7	31.3	30.8
2017	21.8	23.3	32.1	31.7
2018	22.4	23.9	33.0	32.5
2019	23.0	24.6	33.8	33.4
2020	23.6	25.2	34.7	34.3
2021	24.2	25.9	35.7	35.2
2022	24.9	26.6	36.6	36.1
2023	25.6	27.3	37.6	37.1

Figure 6–1 shows the distribution of load impacts by LCA for CBP DA and DO for an August peak day in a 1-in-2 weather year. DA load impacts are concentrated heavily in the relatively small Humboldt LCA, DO load impacts occur primarily in the Greater Bay Area and Greater Fresno LCAs.

[12] Typically, load impacts are larger in the 1-in-10 weather year scenario. However, for DO load impacts in August, the 1-in-10 year values are less than the 1-in-2 values. Such outcomes can occur due to the design of the weather-year scenarios and the allocation of customers across LCAs.

Figure 6–1: Distribution of Load Impacts by LCA for an August Peak Day in 2015 in a 1-in-2 Weather Year (*PG&E CBP DA and DO*)



6.3.2 Hourly reference loads and load impacts

Figure 6–2 shows the forecast reference load, event-day load, and load impacts (right axis) for a typical event day in 2015 in a 1-in-2 weather year for CBP DA.[13] Figure 6–3 shows comparable information for CBP DO.

[13] For this program, program-level impacts and portfolio-level impacts are the same.

Figure 6–2: Hourly Event-Day Load Impacts for the Typical Event Day in 2015 in a 1-in-2 Weather Year – *PG&E CBP DA*

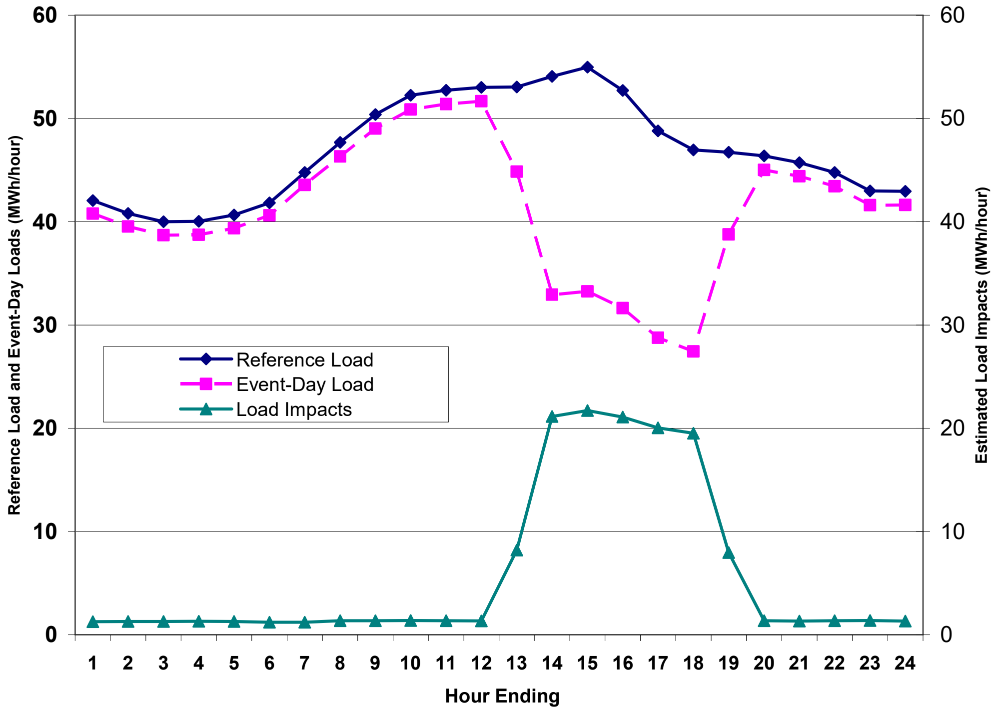
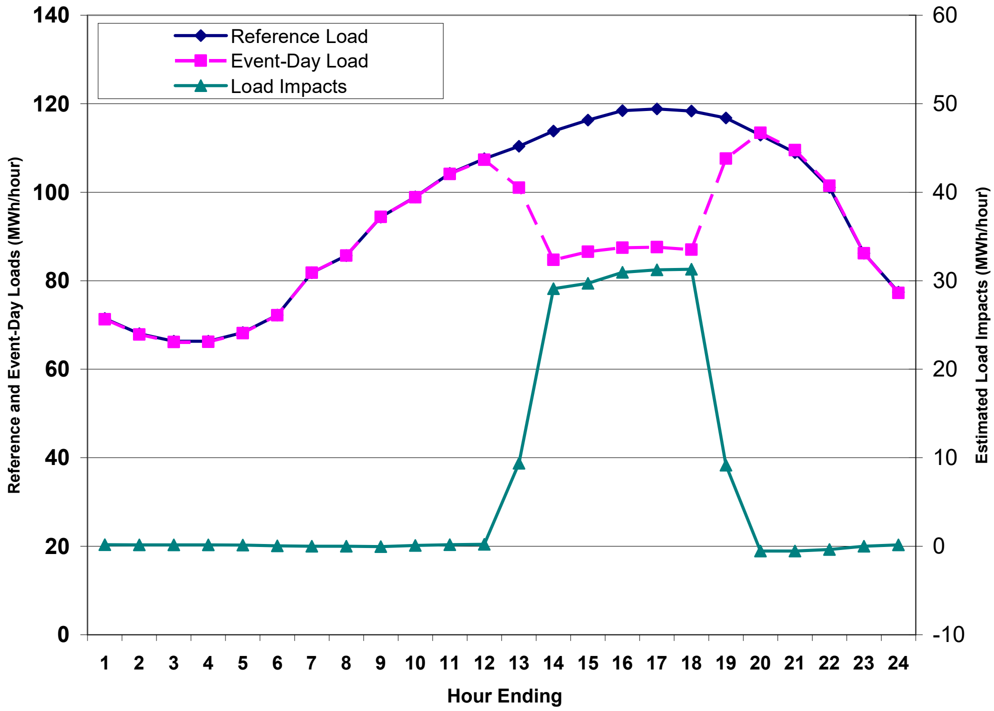


Figure 6–3: Hourly Event-Day Load Impacts for the Typical Event Day in 2015 in a 1-in-2 Weather Year – *PG&E CBP DO*



6.4 *Ex ante* Load Impacts for PG&E's AMP Program

6.4.1 Enrollment and load impact summary

Table 6–3 summarizes anticipated nominations and aggregate load impacts (MW) for AMP DA and DO. Due to the contractual nature of the AMP program, PG&E anticipates that nominations will remain flat from 2014 onward.

Table 6–3: Customer Nominations and *Ex ante* Load Impacts for August in a 1-in-2 Weather Year *PG&E AMP DA and DO*

	Day-Ahead				Day-Of			
Year	Nom. Cust. Accnts.	Load Impact (MW)	Ref. Load (MW)	% Load Impact	Nom. Cust. Accnts.	Load Impact (MW)	Ref. Load (MW)	% Load Impact
2013	459	72.2	213.9	33.8%	1642	175.2	618.8	28.3%
2014	540	85.0	251.6	33.8%	1706	182.0	642.8	28.3%
2015 - 2023	540	85.0	251.6	33.8%	1706	182.0	642.8	28.3%

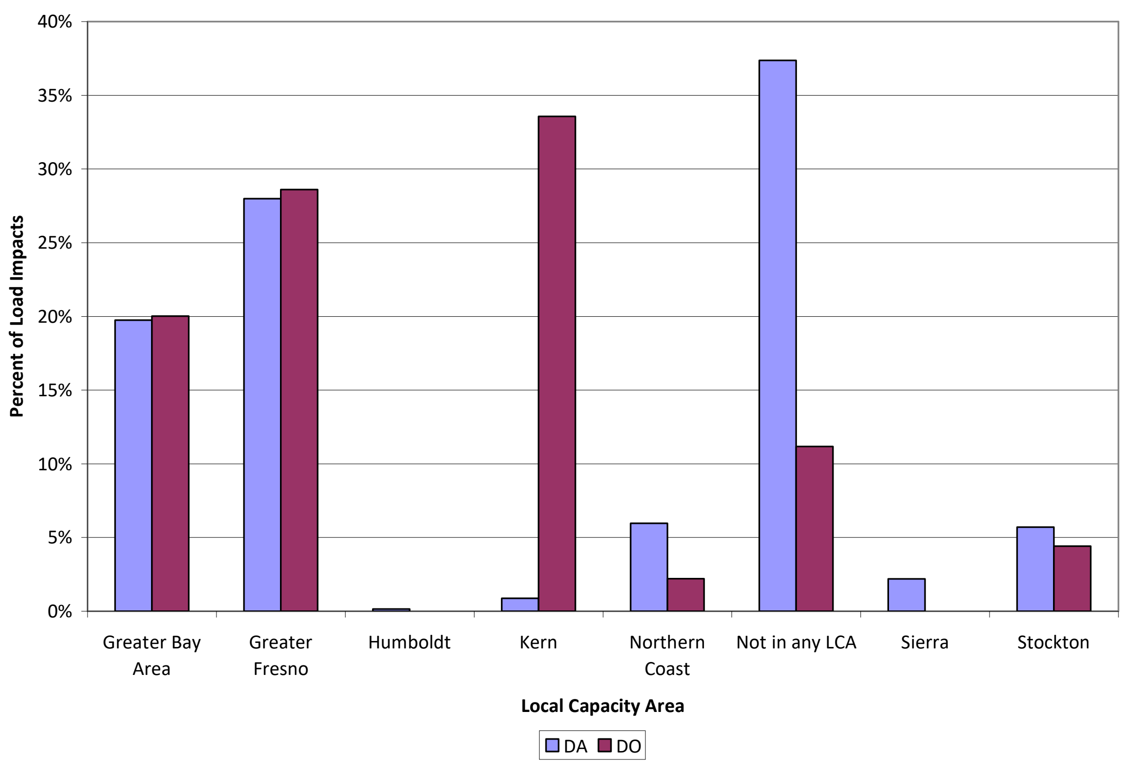
Table 6–4 compares *ex ante* load impacts for DA and DO in 1-in-2 and 1-in-10 weather-years, showing somewhat larger load impacts in 1-in-10 years.

Table 6–4: Average Hourly Load Impacts for an August Peak Day in 1-in-2 and 1-in-10 Weather Years (2013 – 2023) – *PG&E AMP DA and DO*

Year	Day-Ahead		Day-Of	
	1-in-2	1-in-10	1-in-2	1-in-10
2013	72.2	73.5	175.2	178.6
2014	85.0	86.5	182.0	185.5
2015 - 2023	85.0	86.5	182.0	185.5

Figure 6–4 shows the distribution of load impacts by LCA for AMP DA and DO for an August peak day in a 1-in-2 weather year. DA load impacts occur largely in the Greater Bay Area and Greater Fresno LCAs, and outside of any LCA. DO load impacts are concentrated heavily in the relatively small Humboldt LCA, DO load impacts are greatest in Kern, with large shares also in the Greater Bay Area and Greater Fresno LCAs.

Figure 6–4: Distribution of Load Impacts by LCA for an August Peak Day in 2015 in a 1-in-2 Weather Year – *AMP DA and DO*



6.4.2 Hourly reference loads and load impacts

Figure 6–5 shows the forecast reference load, event-day load, and load impacts (right axis) for a typical event day in 2015 in a 1-in-2 weather year for AMP DA. Figure 6–6 shows comparable information for AMP DO.

Figure 6–5: Hourly Event-Day Load Impacts for the Typical Event Day in 2015 in a 1-in-2 Weather Year – *AMP DA*

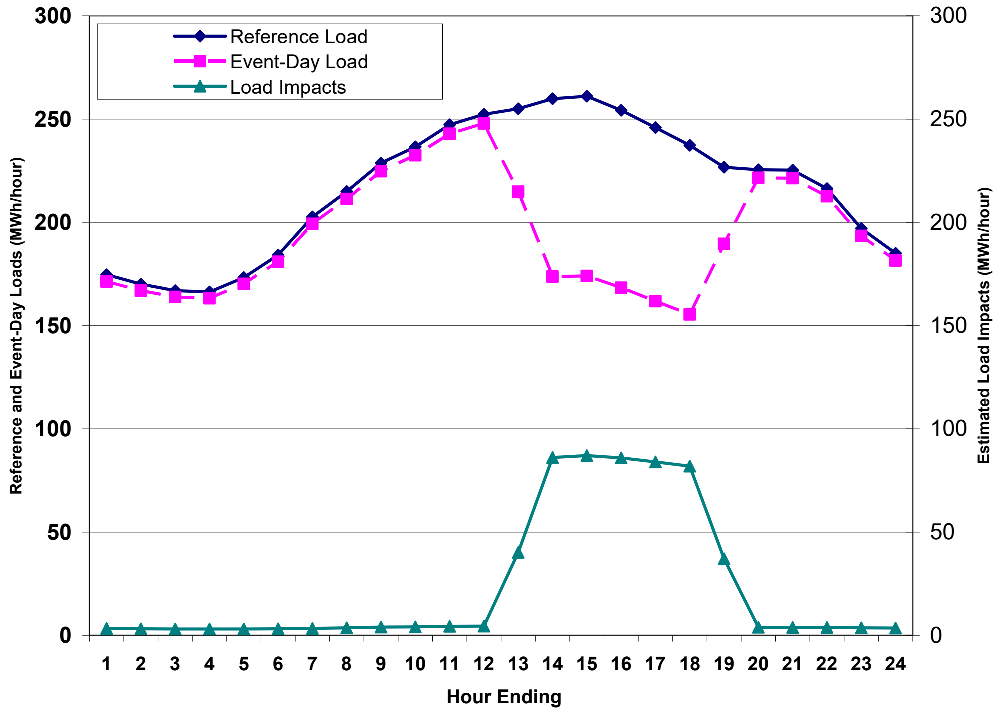
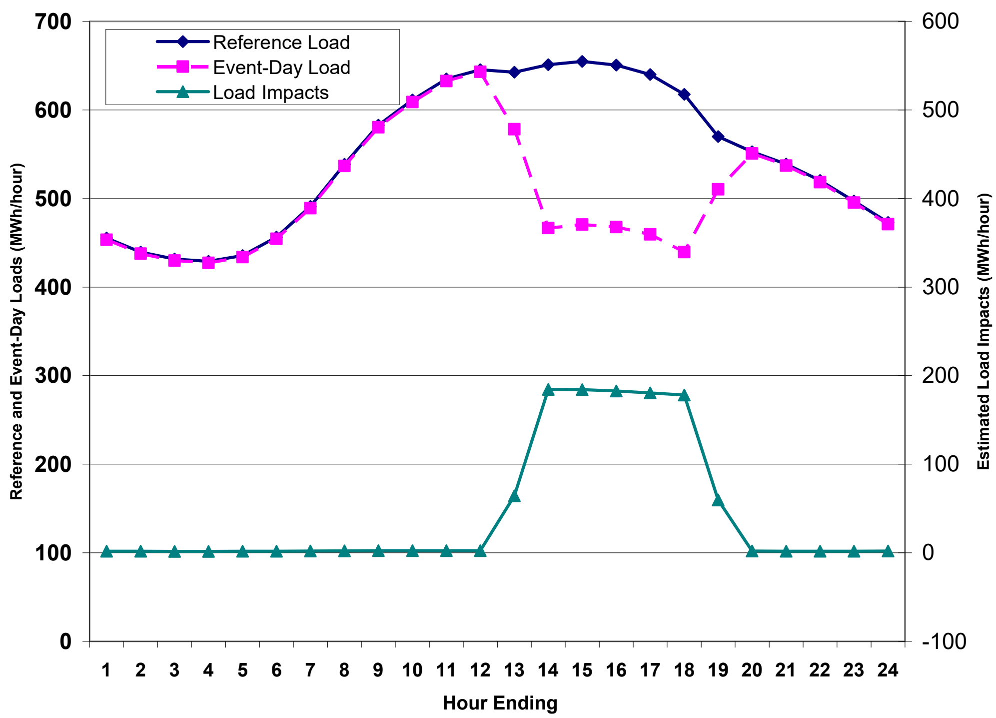


Figure 6–6: Hourly Event Day Load Impacts for the Typical Event Day in 2015 in a 1-in-2 Weather Year – *AMP DO*



6.5 *Ex ante* Load Impacts for SCE's CBP Program

6.5.1 Enrollment forecasts, reference loads and load impacts

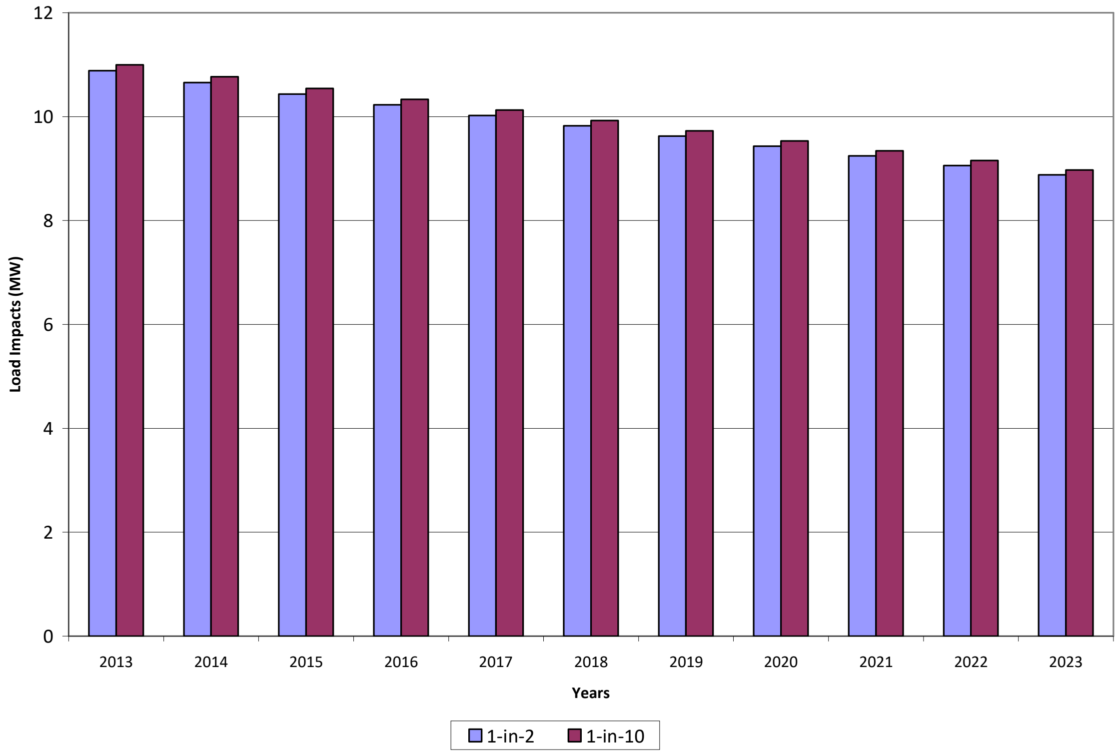
Table 6–5 presents *ex ante* load impacts for SCE's CBP DA and DO. Due to the very small number of DA nominations and imprecise *ex post* load impacts, *ex ante* load impacts are shown as zero. DA nominations are expected to remain small, while DO nominations are anticipated to fall over the forecast horizon due to aggregators moving customers from CBP to DRC. CBP DO load impacts fall from about 11 MW in 2013 to 9 MW in 2023.

Table 6–5: Customer Nominations and *Ex ante* Load Impacts for August in a 1-in-2 Weather Year *SCE CBP DA and DO*

	Day-Ahead				Day-Of			
Year	Nom. Cust. Accnts.	Load Impact (MW)	Ref. Load (MW)	% Load Impact	Nom. Cust. Accnts.	Load Impact (MW)	Ref. Load (MW)	% Load Impact
2013	3	0.0	2.0	0.0%	255	10.9	60.3	18.1%
2014	3	0.0	2.0	0.0%	250	10.7	59.0	18.1%
2015	3	0.0	2.0	0.0%	245	10.4	57.8	18.1%
2016	3	0.0	2.0	0.0%	240	10.2	56.6	18.1%
2017	3	0.0	2.0	0.0%	235	10.0	55.5	18.1%
2018	3	0.0	2.0	0.0%	231	9.8	54.4	18.1%
2019	3	0.0	2.0	0.0%	226	9.6	53.3	18.1%
2020	3	0.0	2.0	0.0%	221	9.4	52.2	18.1%
2021	3	0.0	2.0	0.0%	217	9.2	51.2	18.1%
2022	3	0.0	2.0	0.0%	213	9.1	50.2	18.1%
2023	3	0.0	2.0	0.0%	208	8.9	49.1	18.1%

Figure 6–7 compares CBP DO *ex ante* load impacts for an August peak day in 1-in-2 and 1-in-10 weather years. The distribution of CBP DO load impacts by LCA is shown in the following section, along with results for DRC.

Figure 6–7: Average Event-Hour Load Impacts (MW) by Forecast Year and Weather Scenario for an August Peak Day (2013 – 2023) – *SCE CBP DO*

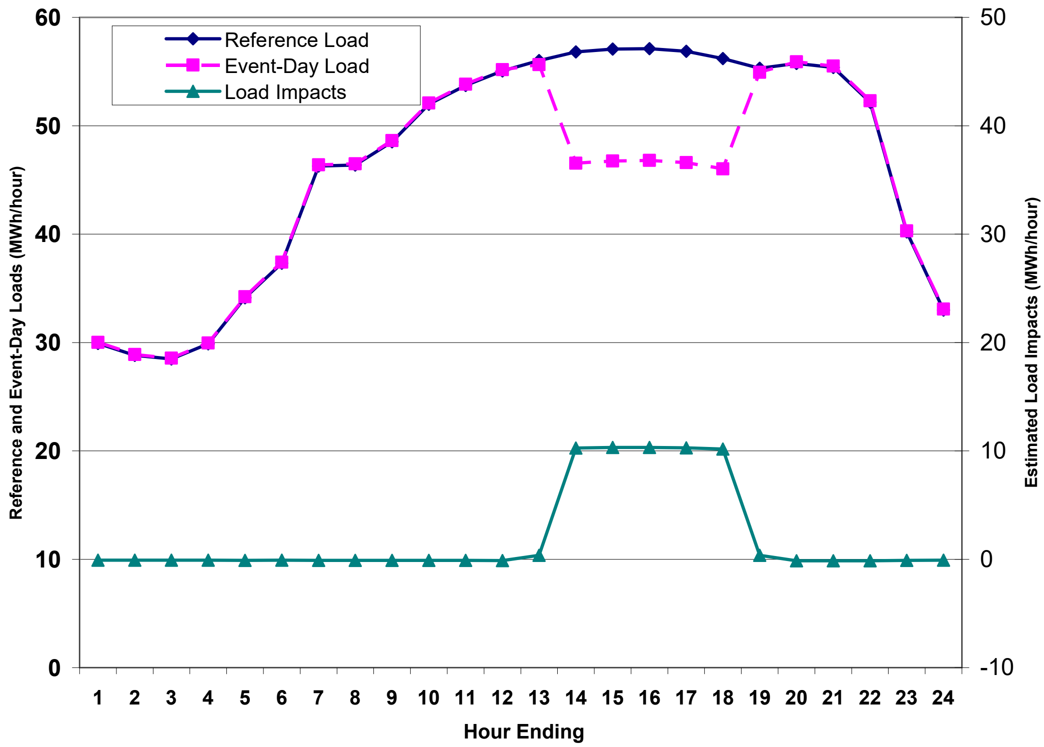


6.5.2 Hourly reference loads and load impacts

Figure 6–8 shows hourly forecast reference and event-day loads, and load impacts for a typical event day in a 1-in-2 weather year in August 2015 for SCE CBP DO.[14] Event-hour load impacts average about 10 MW, which is 18 percent of the reference load.

[14] No figure is show for CBP DA due to the very small number of nominated customers.

Figure 6–8: Hourly Event Day Load Impacts for the Typical Event Day in 2015 in a 1-in-2 Weather Year – *SCE CBP DO*



6.6 *Ex ante* Load Impacts for SCE's DRC Program

6.6.1 Enrollment forecasts, reference loads and load impacts

Table 6–6 shows nomination forecasts, and average hourly reference loads and load impacts for 2013 – 2023 for an August peak day in a 1-in-2 weather year for the SCE DRC DA and DO notice types. Nominations for both DA and DO are anticipated to grow substantially over the forecast time horizon, as are load impacts. Percentage load impacts are 50 percent for DA and 27 percent for DO.

Table 6–6: Customer Nominations and *Ex ante* Load Impacts for August in a 1-in-2 Weather Year *SCE DRC DA and DO*

	Day-Ahead				Day-Of			
Year	Nom. Cust. Accnts.	Load Impact (MW)	Ref. Load (MW)	% Load Impact	Nom. Cust. Accnts.	Load Impact (MW)	Ref. Load (MW)	% Load Impact
2013	123	15.9	31.6	50.4%	1468	129.2	486.0	26.6%
2014	135	17.5	34.7	50.4%	1616	142.1	534.8	26.6%
2015	149	19.2	38.2	50.4%	1778	156.4	588.4	26.6%
2016	163	21.0	41.8	50.4%	1948	171.4	644.9	26.6%
2017	178	23.0	45.8	50.4%	2135	187.9	706.8	26.6%
2018	195	25.2	50.1	50.4%	2340	205.9	774.7	26.6%
2019	214	27.6	54.9	50.4%	2565	225.7	849.0	26.6%
2020	234	30.3	60.1	50.4%	2811	247.3	930.5	26.6%
2021	256	33.1	65.8	50.4%	3081	271.1	1019.9	26.6%
2022	281	36.3	72.0	50.4%	3377	297.1	1117.8	26.6%
2023	307	39.7	78.9	50.4%	3701	325.6	1225.1	26.6%

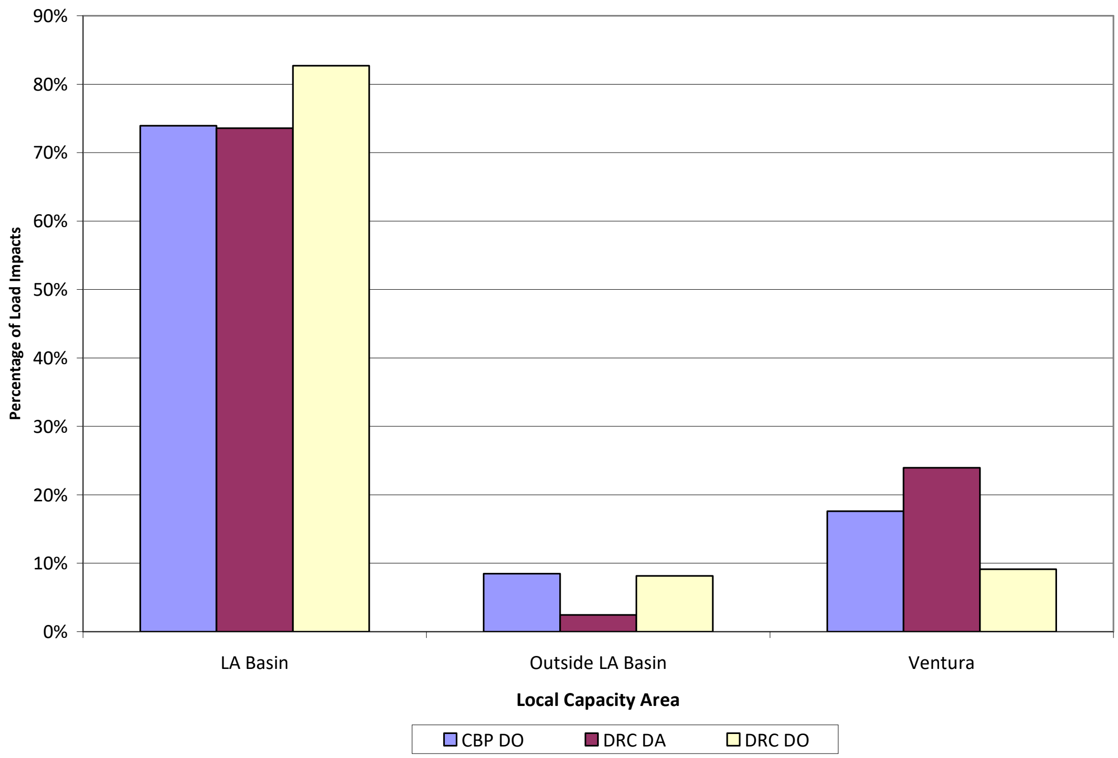
Table 6–7 compares *ex ante* load impacts for DA and DO in 1-in-2 and 1-in-10 weather-years, showing somewhat larger load impacts in 1-in-10 years.

Table 6–7: Average Hourly Load Impacts for an August Peak Day in 1-in-2 and 1-in-10 Weather Years (2013 – 2023) – *SCE DRC DA and DO*

	Day-Ahead		Day-Of	
Year	1-in-2	1-in-10	1-in-2	1-in-10
2013	15.9	16.0	129.2	130.3
2014	17.5	17.6	142.1	143.4
2015	19.2	19.3	156.4	157.8
2016	21.0	21.2	171.4	173.0
2017	23.0	23.2	187.9	189.6
2018	25.2	25.4	205.9	207.8
2019	27.6	27.8	225.7	227.7
2020	30.3	30.4	247.3	249.6
2021	33.1	33.3	271.1	273.5
2022	36.3	36.5	297.1	299.8
2023	39.7	40.0	325.6	328.6

Figure 6-9 shows the distribution of load impacts across LCAs for DRC DA and DO, as well as for CBP DO. More than 70 percent of load impacts for all three program types occur in the LA Basin, with most of the remainder in the Ventura LCA.

Figure 6–9: Load Impacts by LCA for the August 2012 Typical Day in a 1-in-2 Weather Year – *CBP DO, and DRC DA and DO*



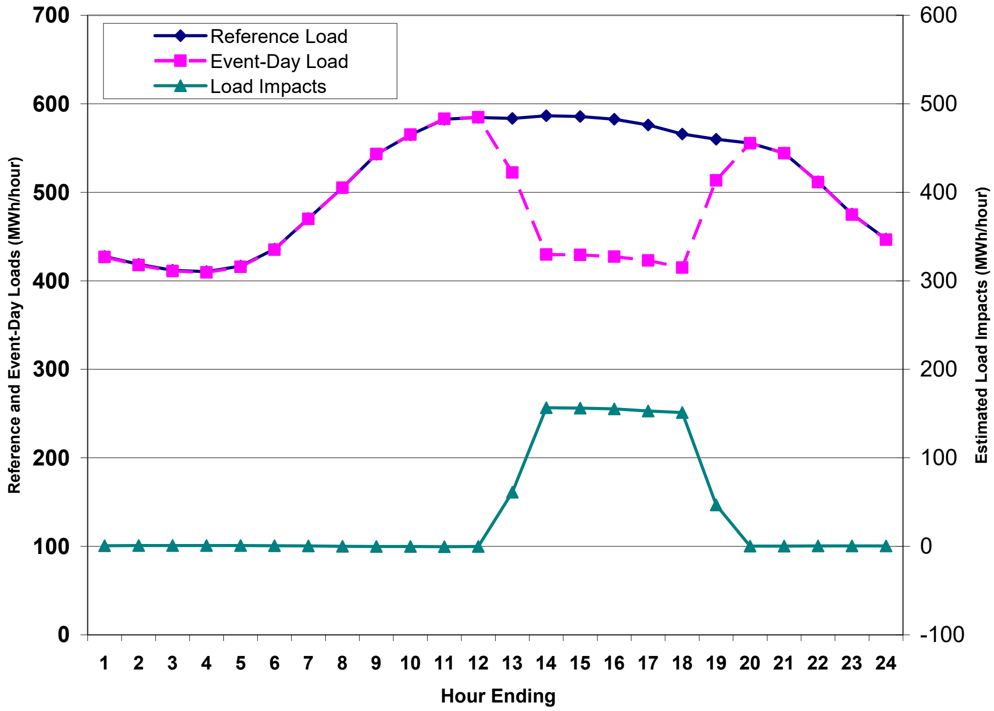
6.6.2 Hourly reference loads and load impacts

Figures 6–10 and 6–11 show the hourly profiles of forecast loads and load impacts for a typical event day in 2015, in a 1-in-2 weather year, for SCE's DRC DA and DO notice types. Event-hour load impacts average approximately 20 MW for DA, which is 50 percent of the reference load. DO load impacts are about 150 MW, which is approximately 27 percent of the reference load.

Figure 6–10: Hourly Event Day Load Impacts for the Typical Event Day in 2015 in a 1-in-2 Weather Year – *SCE DRC DA*

Figure removed due to confidentiality.

Figure 6–11: Hourly Event Day Load Impacts for the Typical Event Day in 2015 in a 1-in-2 Weather Year – *SCE DRC DO*



6.7 *Ex ante* Load Impacts for SDG&E's CBP

6.7.1 Enrollment forecasts, reference loads and load impacts

SDG&E anticipates that nominations and load impacts for CBP DA and DO will remain constant over the forecast period, as shown in Table 6–8. Nominations are 81 customer accounts for DA and 381 for DO. Average hourly load impacts are 7.7 MW for DA and 10.4 MW for DO, representing 30 percent and 13 percent of the reference load respectively.

Table 6–8: Customer Nominations and *Ex ante* Load Impacts for August in a 1-in-2 Weather Year *SDG&E CBP DA and DO*

Year	Day-Ahead				Day-Of			
	Nom. Cust. Accnts.	Load Impact (MW)	Ref. Load (MW)	% Load Impact	Nom. Cust. Accnts.	Load Impact (MW)	Ref. Load (MW)	% Load Impact
2013	81	7.7	26.2	29.5%	371	10.4	82.0	12.7%
2014 - 2023	81	7.7	26.2	29.5%	371	10.4	82.0	12.7%

Table 6–9 compares DA and DO load impacts for an August peak day in 1-in-2 and 1-in-10 weather years.

Table 6–9: Average Hourly Load Impacts for an August Peak Day in 1-in-2 and 1-in-10 Weather Years (2013 – 2023) – *SDG&E CBP DA and DO*

Year	Day-Ahead		Day-Of	
	1-in-2	1-in-10	1-in-2	1-in-10
2013	7.7	7.6	10.4	10.5
2014 - 2023	7.7	7.6	10.4	10.5

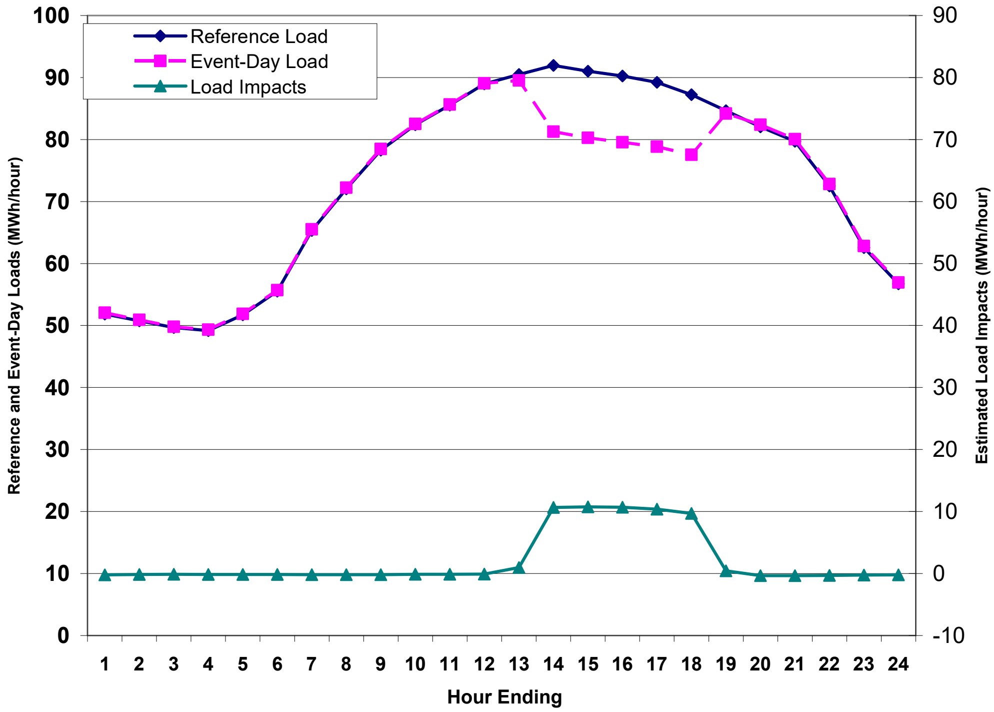
6.7.2 Hourly reference loads and load impacts

Figure 6–12 shows *ex ante* hourly reference load, event-day load, and load impacts for a typical event day in 2015 in a 1-in-2 weather year for CBP DA. Event-hour load impacts average 7.7 MW, which represents approximately 30 percent of the reference load. Figure 6–13 shows comparable information for CBP DO. Event-hour load impacts for CBP DO average 10.4 MW, which represents approximately 13 percent of the reference load.

Figure 6–12: Hourly Event-Day Load Impacts for the Typical Event Day in 2015 in a 1-in-2 Weather Year – *SDG&E CBP DA*

Figure removed due to confidentiality.

Figure 6–13: Hourly Event-Day Load Impacts for the Typical Event Day in 2015 in a 1-in-2 Weather Year – *SDG&E CBP DO*



6.8 Comparisons to Previous *Ex ante* Forecast

Table 6–10 compares program-level *ex ante* nominations and aggregate load impacts for 2013 from the current and two previous aggregator evaluation studies. Where available, we use August 1-in-2 forecasts. As noted earlier, the current (2012) study and the 2010 study were conducted by CA Energy Consulting, while the 2011 study was conducted by FSC.[15] As for the *ex post* load impacts, the 2013 values of the *ex ante* forecasts are reasonably consistent across the current and two previous aggregator studies. Some differences are noticeable, such as SCE's expectation of falling participation in CBP. PG&E anticipates higher levels of load impacts for both AMP DA and DO, while SCE expects some fall-off from last year's forecast for DRC DO.

[15] It should be noted that the 2010 study was the last one to use "enrollments" rather than "nominations" for most aggregator programs. Due to some confusion in distinguishing the two concepts (*e.g.*, customers enrolled in CBP do not receive a notice-type designation unless or until they are nominated), subsequent studies have focused on nominations.

Table 6–10: Comparison of *Ex ante* Forecasts for 2013 in Current and Previous Studies

Utility	Study Year	Nominations		Aggregate Load Impacts (MW)	
		DA	DO	DA	DO
PG&E - CBP	2012	168	374	19.6	28.9
	2011	225	274	14.2	20.3
	2010	738	352	24.7	29.8
SCE - CBP	2012	3	255	0.0	10.9
	2011	123	475	5.7	22.1
	2010	132	504	1.4	19.4
SDG&E -CBP	2012	81	371	7.7	10.4
	2011	57	357	13.5	12.9
	2010	152	456	11.1	14.6
PG&E - AMP	2012	459	1,639	72.2	175.2
	2011	221	1,370	44.0	154.5
	2010	157	836	40.0	149.0
SCE - DRC	2012	123	1,468	15.9	129.2
	2011	214	1,837	13.5	168.9
	2010*	380	1,192	25.2	78.5

* Values in 2010 study are for 2012, since 2013 values were zero at the time.

7. RECOMMENDATIONS

Last year's evaluation recommended maintaining the CBP programs due to their useful role in both providing opportunities for aggregators that don't have bilateral contracts with utilities, and providing aggregators that do have contracts with a pool of customers that they may eventually move to contract-based programs (*e.g.*, AMP and DRC). However, it is worth asking whether programs with extremely small enrollment, such as SCE CBP DA should be maintained as is, or if aggregators should be encouraged to bring in additional customers, even if to transition them to other program options.

APPENDIX A. MODEL SELECTION AND VALIDITY ASSESSMENT

A.1 Model Specification Tests

A range of model specifications were tested before arriving at the model used in the *ex post* load impact analysis. The basic structure of the model is shown in Section 3.2.1. The tests are conducted using average-customer data (by utility and notice) rather than at the individual customer level at the utility/program level. We combined across notice levels within program. Model variations include:

1. *Weather variables*. We tested 18 different combinations of weather variables. The weather variables include: temperature-humidity index (THI)[16]; the 24-hour moving average of THI; heat index (HI)[17]; the 24-hour moving average of HI; cooling degree hours (CDH)[18], including both a 60 and 65 degree Fahrenheit threshold; the 3-hour moving average of CDH; the 24-hour moving average of CDH; the one-day lag of cooling degree days (CDD)[19]. A list of the 18 combinations of these variables that we tested is provided in Table A-1.
2. *Level models versus difference models*. The dependent variable in the model presented in Section 3.2.1 is the level of customer usage in a particular hour. This has been the most common way of estimating load impact models in our previous evaluations. In our specification tests, we include models of *differences* in usage across days that attempt to explain day-to-day load changes, including those on event days. These models explain the difference in load for each hour relative to the same hour on the previous day as a function of the corresponding differences in weather conditions and day-types. The potential advantage of this approach is that each hour's load is evaluated relative only to loads on neighboring days, which may remove spurious effects across time (for which we are unable to control due to incomplete information).

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[16] THI = $T - 0.55 \times (1 - HUM) \times (T - 58)$ if T>=58 or THI = T if T<58, where T = ambient dry-bulb temperature in degrees Fahrenheit and HUM = relative humidity (where 10 percent is expressed as "0.10").

[17] HI = $c_1 + c_2T + c_3R + c_4TR + c_5T^2 + c_6R^2 + c_7T^2R + c_8TR^2 + c_9T^2R^2 + c_{10}T^3 + c_{11}R^3 + c_{12}T^3R + c_{13}TR^3 + c_{14}T^3R^2 + c_{15}T^2R^3 + c_{16}T^3R^3$, where T = ambient dry-bulb temperature in degrees Fahrenheit and R = relative humidity (where 10 percent is expressed as "10"). The values for the various c's may be found here: http://en.wikipedia.org/wiki/Heat_index.

[18] Cooling degree hours (CDH) was defined as MAX[0, Temperature – Threshold], where Temperature is the hourly temperature in degrees Fahrenheit and Threshold is either 60 or 65 degrees Fahrenheit. Customer-specific CDH values are calculated using data from the most appropriate weather station.

[19] Cooling degree days (CDD) are defined as MAX[0, (Max Temp + Min Temp) / 2 – 60], where Max Temp is the daily maximum temperature in degrees Fahrenheit and Min Temp is the daily minimum temperature. Customer-specific CDD values are calculated using data from the most appropriate weather station.

Table A–1: Weather Variables Included in the Tested Specifications

Model Number	Included Weather Variables
1	THI
2	HI
3	CDH60
4	CDH65
5	CDH60_MA3
6	CDH65_MA3
7	THI THI_MA24
8	HI HI_MA24
9	CDH60 CDH60_MA24
10	CDH65 CDH65_MA24
11	CDH60_MA3 CDH60_MA24
12	CDH65_MA3 CDH65_MA24
13	THI Lag_CDD60
14	HI Lag_CDD60
15	CDH60 Lag_CDD60
16	CDH65 Lag_CDD60
17	CDH60_MA3 Lag_CDD60
18	CDH65_MA3 Lag_CDD60

The model variations are evaluated according to two primary validation tests:

1. Ability to predict usage on event-like *non-event days*. Specifically, we identified a set of days that were similar to event days, but were not called as event days (*i.e.*, "test days"). The use of non-event test days allows us to test model performance against known "reference loads," or customer usage in the absence of an event. We estimate the model excluding one of the test days and use the estimates to make out-of-sample predictions of customer loads on that day. The process is repeated for all of the test days. The model fit (*i.e.*, the difference between the actual and predicted loads on the test days, during afternoon hours in which events are typically called) is evaluated using mean absolute percentage error (MAPE) as a measure of accuracy, and mean percentage error (MPE) as a measure of bias.
2. Performance on *synthetic* event days (*e.g.*, event-like non-event days that are treated as event days in estimation), to test for "event" coefficients that demonstrate statistically significant bias, as opposed to expected non-significance, since customers have no reason to modify usage on days that are not actual events. This is an extension of the previous test. The same test days are used, with a set of hourly "synthetic" event variables included in addition to the rest of the specification to test whether non-zero load impacts are estimated for these days. A successful test involves synthetic event load impact coefficients that are not statistically significantly different from zero.

A.1.1 Selection of Event-Like Non-Event Days

In order to select event-like non-event days, we created an average weather profile using the load-weighted average across customers, each of which is associated with a weather station. We "scored" each non-holiday weekday by comparing the dry-bulb temperature and relative humidity to the values for each event day. For example, we calculated the following statistic for each day relative to the first day: abs($Temp_t$ – $Temp_{Evt}$) / StdDev($Temp$). A similar score was calculated for the relative humidity, and the sum of the temperature and humidity scores was used to rank the days. We selected the five lowest-scoring days (low scores indicate greater similarity to the event day) for each event day. Days were excluded from the list as necessary (*e.g.*, to exclude other event days).

Table A–2: List of Event-Like Non-Event Days by Program

PG&E AMP	PG&E CBP	SCE DRC	SCE CBP	SDG&E CBP
6/1/2012	6/1/2012	6/4/2012	6/6/2012	8/16/2012
7/30/2012	7/30/2012	7/10/2012	7/2/2012	8/21/2012
7/31/2012	7/31/2012	8/6/2012	7/26/2012	8/28/2012
8/2/2012	8/2/2012	8/17/2012	7/27/2012	8/30/2012
8/8/2012	8/8/2012	8/28/2012	8/3/2012	9/5/2012
8/14/2012	8/14/2012	10/22/2012	8/6/2012	9/18/2012
8/16/2012	8/16/2012		8/8/2012	9/28/2012
8/29/2012	8/29/2012		8/9/2012	10/17/2012
			8/27/2012	
			9/4/2012	
			9/17/2012	
			9/24/2012	
			9/26/2012	
			10/4/2012	
			10/8/2012	

A.1.2 Results from Tests of Alternative Weather Specifications

For each utility and program, we tested 36 specifications, which is 18 different sets of weather variables, each estimated in levels and differences. The aggregate load used in conducting these tests was constructed separately for each utility/program and included only nominated service accounts.

The tests are conducted by estimating one model for every utility/program (5), specification (36), and event-like day (8 for PG&E and SDG&E, 6 for SCE DRC, and 15 for SCE CBP). Each model excludes one event-like day from the estimation model and uses the estimated parameters to predict the usage for that day. The MPE and MAPE are calculated across the event windows of the withheld days.

Table A–3 shows the adjusted R-squared, mean percentage error (MPE), and mean absolute percentage error (MAPE) for the selected ("winning") specification for each utility and program.

Across all utilities and programs, the level models perform better than the models of differences. Within the type of model (*i.e.*, level or difference), the range of results is quite small. For example, the PG&E AMP level models have an adjusted R2 ranging from 0.978 to 0.981; a MPE that ranges from 0.0% to 0.4%; and a MAPE that ranges from 1.0% to 1.4%. Because of the similarity in the outcomes across specifications, there was little benefit in selecting the best specification for each utility/program. Instead, we selected the single specification that performed best across all programs, which was specification 12 in Table 7.1 (including the 3-hour and 24-hour moving averages of CDH with a 65 degree threshold).

Table A–3: Specification Test Results for the "Winning" Model

Program	Adjusted R^2	MPE	MAPE
PG&E AMP	0.979	0.0%	1.0%
PG&E CBP	0.992	0.3%	1.1%
SCE DRC	0.987	-0.5%	1.0%
SCE CBP	0.989	-0.1%	1.3%
SDG&E CBP	0.982	1.1%	2.5%

For each specification, we estimated a single model that included all of the days (*i.e.*, not withholding any event-like days), but using a single set of actual event variables (*i.e.*, a 24-hour profile of the average event-day load impacts). The results of these tests reinforced the conclusion that very little is at stake when selecting from the specifications, as the average hourly load impact profile was quite stable across models.

Figures A–1 through A–5 show the estimated hourly load impacts for each of the 18 level models by utility/program. There were differences between the load impacts for the level versus differences models, but given the performance of the differences models, we show only the results for the levels models here. The selected specification is highlighted in bold yellow. As the figures show, the load impacts would not change substantially if we were to alter the weather specification.

Figure A–1: Average Event-Hour Load Impacts by Specification, *PG&E AMP*

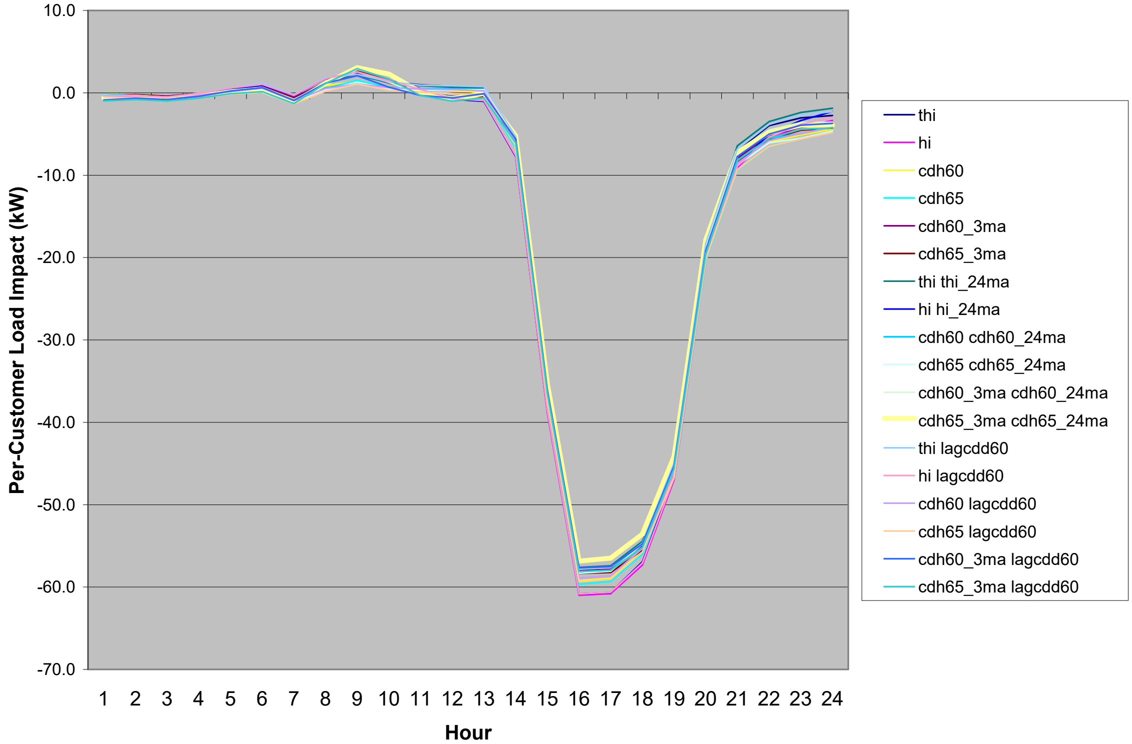


Figure A–2: Average Event-Hour Load Impacts by Specification, *PG&E CBP*

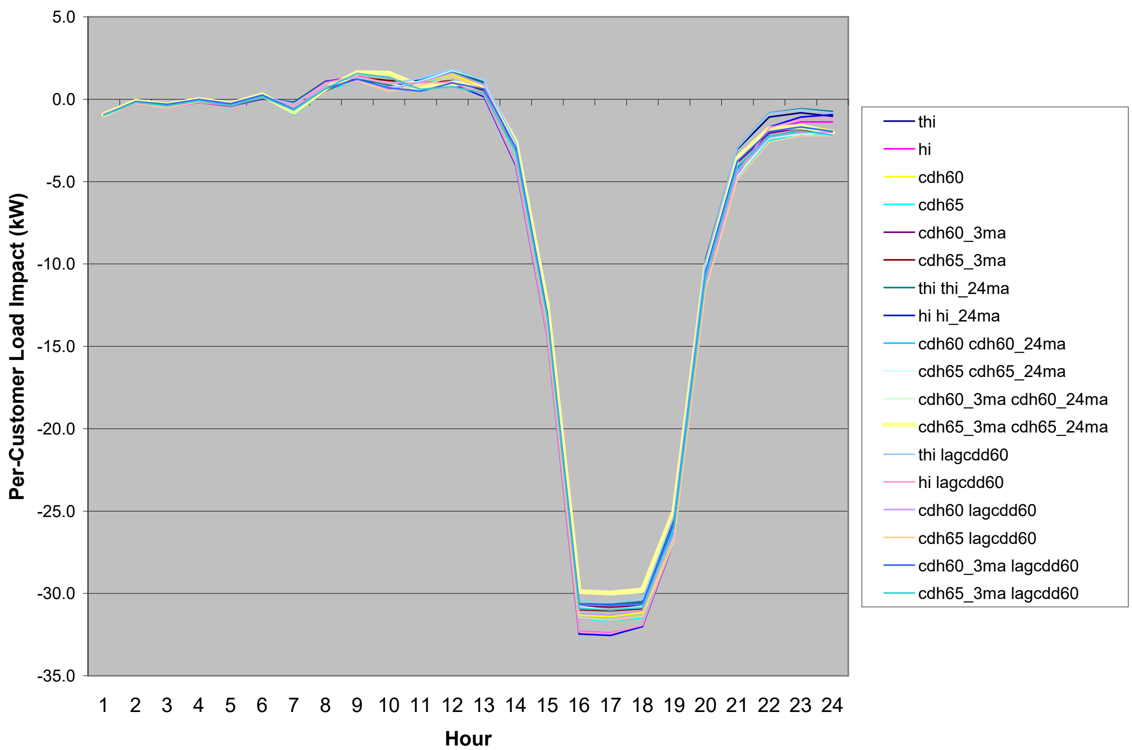


Figure A–3: Average Event-Hour Load Impacts by Specification, *SCE DRC*

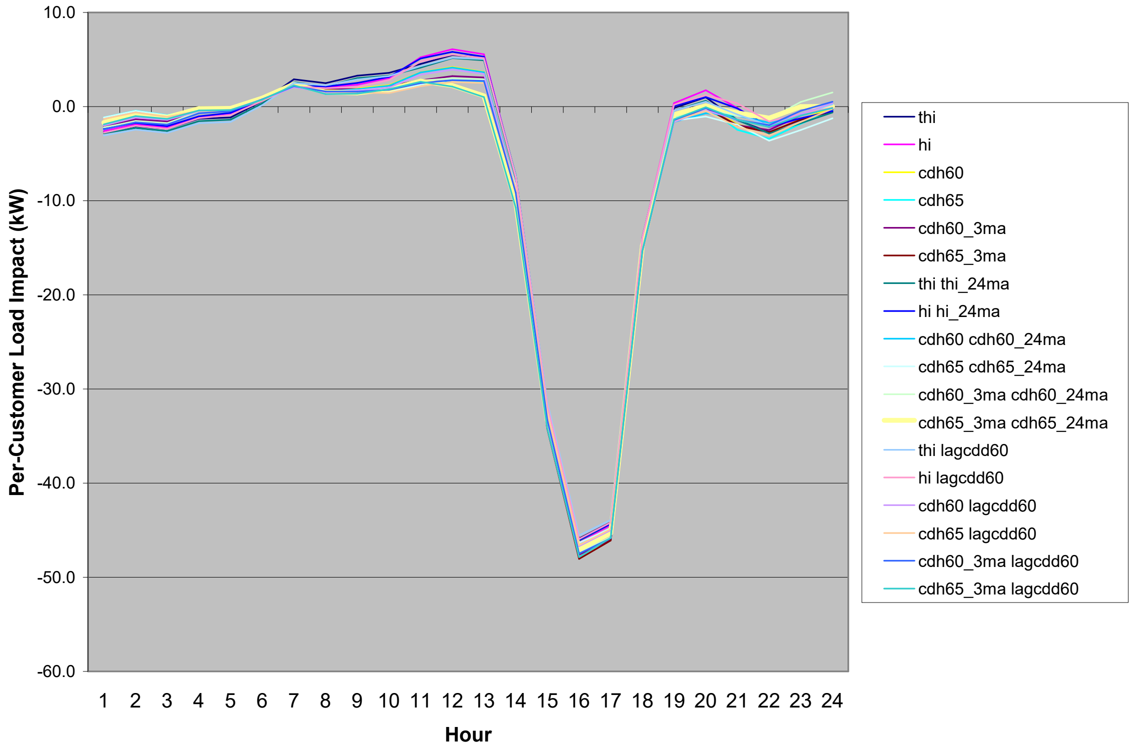


Figure A–4: Average Event-Hour Load Impacts by Specification, *SCE CBP*

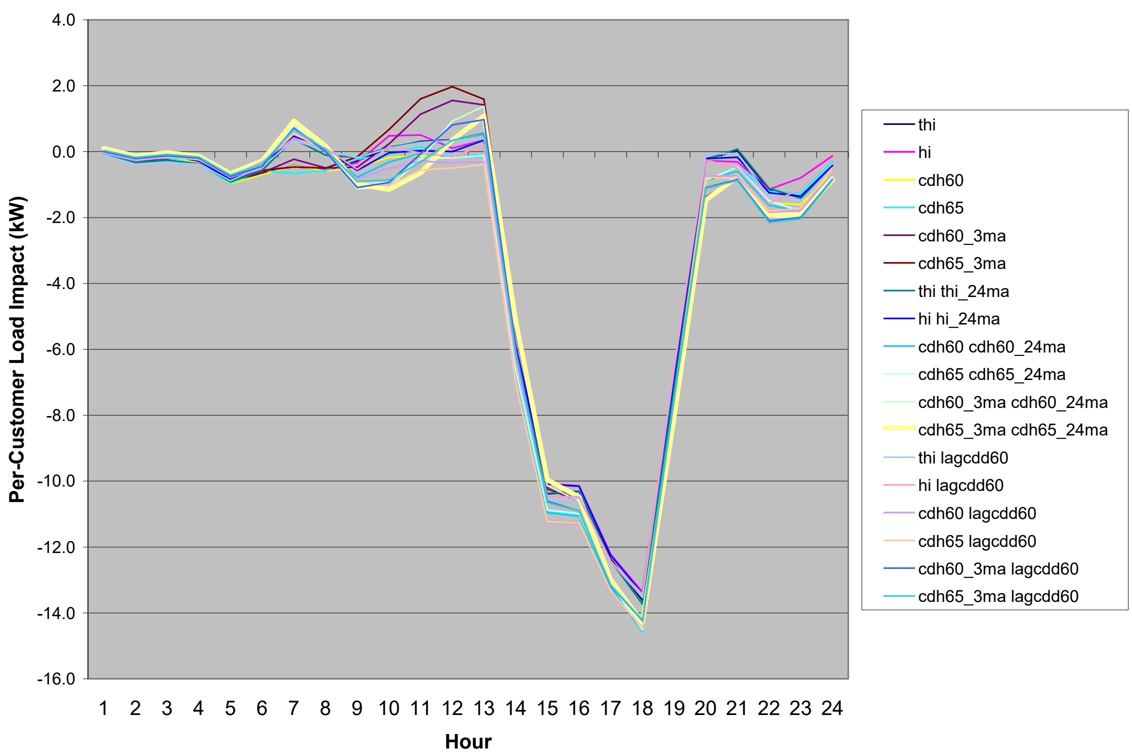
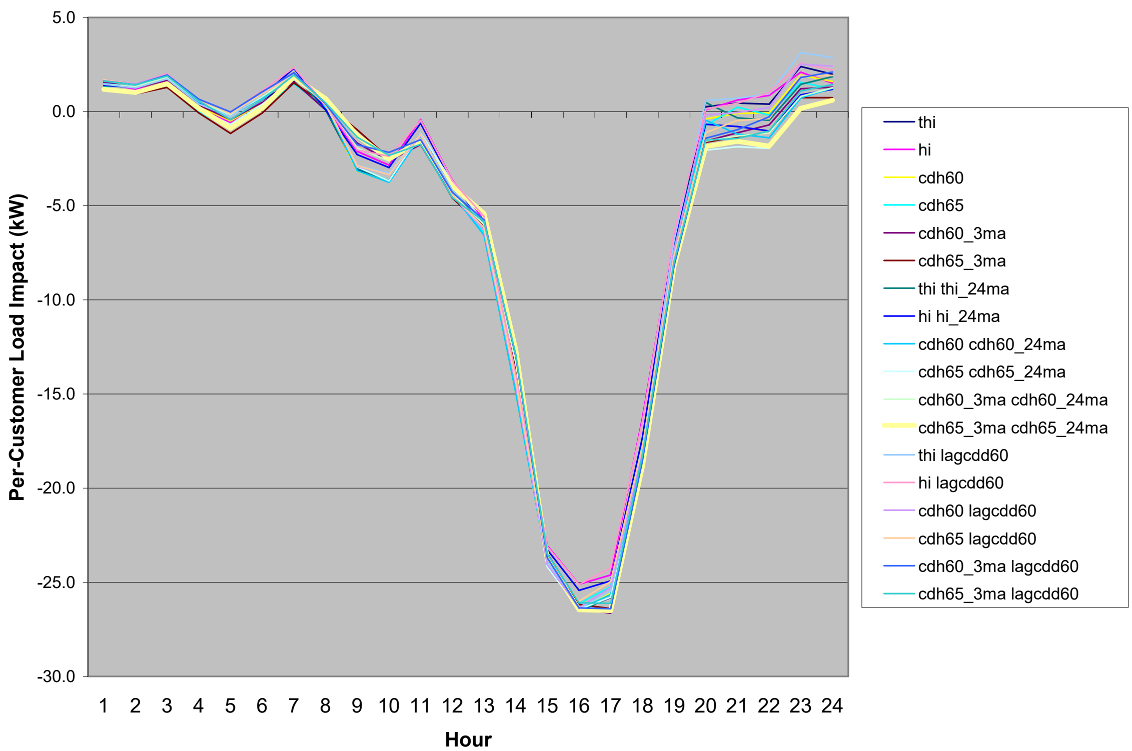


Figure A–5: Average Event-Hour Load Impacts by Specification, *SDG&E CBP*



A.1.3 Synthetic Event Day Tests

For the specification selected from the testing described in Section A.1.2, we conducted an additional test. The selected specification was estimated on the aggregate customer data, including a set of 24 hourly "synthetic" event-day variables. These variables equaled one on the days listed in Table A–1, with a separate estimate for each hour of the day.

If the model produces synthetic event-day coefficients that are not statistically significantly different from zero, the test provides some added confidence that our actual event-day coefficients are not biased. That is, the absence of statistically significant results for the synthetic event days indicates that the remainder of the model is capable of explaining the loads on those days.

Table A–4 presents the results of this test for each utility/program, showing only the coefficients during a typical event window of hours-ending 14 through 19. The values in parentheses are p-values, or measures of statistical significance. A p-value that is less than 0.05 indicates that the estimated coefficient is statistically significantly different from zero with 95 percent confidence. For PG&E and SCE, the p-values in Table A–4 are uniformly higher than this standard, indicating that each model "passes" this test. SDG&E's CBP program does not pass this test, with the test indicating the potential for some upward bias in the estimated load impacts (*i.e.*, the model estimates load reductions where there should be none). However, as the results in Figure A-5 show, this outcome is not remedied by selecting a different specification, as the alternative models produce very similar load impact estimates.

Table A–4: Synthetic Event-Day Tests by Program

Hour	PG&E AMP	PG&E CBP	SCE DRC	SCE CBP	SDG&E CBP
14	1.012 (0.694)	0.746 (0.361)	0.237 (0.883)	1.209 (0.334)	-4.064 (0.072)
15	1.120 (0.664)	0.518 (0.526)	2.241 (0.163)	0.474 (0.704)	-4.190 (0.063)
16	0.953 (0.713)	0.603 (0.462)	2.140 (0.183)	0.128 (0.919)	-3.105 (0.169)
17	0.279 (0.914)	-0.319 (0.698)	2.010 (0.212)	-0.273 (0.827)	-3.787 (0.093)
18	-0.188 (0.942)	-1.007 (0.222)	1.722 (0.285)	-0.659 (0.599)	-4.373 (0.052)
19	-0.825 (0.751)	-1.196 (0.147)	1.195 (0.459)	1.123 (0.371)	-1.400 (0.535)

A.2 Potential Modifications to Customer-Level Models

While the specification tests described in Section A.1 were conducted on aggregated load profiles for each utility, the *ex post* load impacts are derived from the results of customer-level models. We examined the estimated load impacts from these models to determine whether any modifications to the estimates are required. We do this by comparing the observed hourly event-day loads to the observed loads from similar days to determine a “day matching” load impact that may be compared to the estimated load impacts. In this evaluation, we elected not to modify any of the estimated load impacts as a result of these inspections.

ADDITIONAL APPENDICES

The following Appendices accompany this report. Each is an Excel file that can produce the tables required by the Protocols.

Study Appendix B	PG&E CBP Ex-Post Load Impact Tables
Study Appendix C	SCE CBP Ex-Post Load Impact Tables
Study Appendix D	SDG&E CBP Ex-Post Load Impact Tables
Study Appendix E	PG&E AMP Ex-Post Load Impact Tables
Study Appendix F	SCE DRC Ex-Post Load Impact Tables
Study Appendix G	PG&E CBP Ex-Ante Load Impact Tables
Study Appendix H	SCE CBP Ex-Ante Load Impact Tables
Study Appendix I	SDG&E CBP Ex-Ante Load Impact Tables
Study Appendix J	PG&E AMP Ex-Ante Load Impact Tables
Study Appendix K	SCE DRC Ex-Ante Load Impact Tables