2010 Load Impact Evaluation of California Statewide Aggregator Demand Response Programs: *Ex Post and Ex Ante Final Report*

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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 2010.

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"), SCE's Demand Response Contracts ("DRC"), and the Demand Smart Program ("DSP") operated by SDG&E.

The primary goals of this evaluation study are the following:

1. Estimate the *ex post* load impacts for program year 2010; and
2. Estimate *ex ante* load impacts for the programs for years 2011 through 2020

Enrollment in the various aggregator programs and product types ranged from 80 customer accounts in SCE's day-ahead CBP to 1,750 in SCE's day-of DRC program. With the exception of PG&E's CBP program, enrollment in the DO product type generally exceeded that in the corresponding DA product type.

The number of aggregator DR events called in 2010 varied considerably across utilities and product types. The PG&E AMP and SCE DRC portfolios were called only once or twice for test events. In contrast, the statewide CBP programs were called 11, 19, and 13 times by PG&E, SCE and SDG&E respectively, while SDG&E called 10 DSP events.

Hourly ex post load impacts were estimated for each program and event during the summer of 2010, using regression analysis of hourly customer-level load, weather, and event data. Estimated load impacts were reported at the program level for each event, for both product types (DA and DO). Load impacts for the average, or typical event were also reported by industry type and CAISO local capacity area where relevant. A high-level summary of ex post load impacts is the following:

- Estimated average hourly *ex post* load impacts for the typical event for the statewide CBP program at PG&E, SCE and SDG&E were 11 MW, 0.8 MW, and

9.6 MW respectively, for the DA product type, and 27.9 MW, 15.4 MW, and 8.7 MW for the DO option.

- Average hourly load impacts for the average event for PG&E's AMP DO product type was 104.9 MW.
- Average hourly load impacts for the typical event for SCE's DRC DA and DO product types were 8.7 MW and 113.3 MW.
- Average hourly load impacts for the average event for SDG&E's DSP DO program were 7.8 MW.

Ex ante load impacts for 2011 through 2020 were developed using reference load profiles and per-customer load impacts generated from the ex post load impact results, along with enrollment forecasts provided by the utilities.

Based on anticipated aggregator contract quantities and expected changes in program enrollments, estimated average hourly *ex ante* load impacts for 2012, for a typical event day in a 1-in-2 weather scenario, are the following:

- For PG&E's CBP DA and DO products – 24.4 MW and 28.3 MW
- For SCE's CBP DA and DO products – 1.2 MW and 18.2 MW
- For SDG&E's CBP DA and DO products – 10.2 MW and 12.5 MW
- For PG&E's AMP DA and DO contracts – 40 MW and 149 MW
- For SCE's DRC DA and DO contracts – 25.2 MW and 78.5 MW
- For SDG&E's DSP DO contract – 14.9 MW.

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 2010. 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 Contracts ("DRC"), and the Demand Smart Program ("DSP"), operated by SDG&E.

The primary goals of this evaluation study are the following:

1. Estimate the *ex post* load impacts for program year 2010; and
2. Estimate *ex ante* load impacts for the programs for years 2011 through 2021

ES.1 Program Resources

CBP

The CBP program provides month to month capacity payments ($/kW) to aggregators based on the nominated kW load, the specific operating month and program option (DA or DO). Additional energy payments ($/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. Participants 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, 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.

AMP

Under the AMP program, each aggregator operates their resource portfolio under a bilateral forward 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, either with DA or DO trigger. The aggregator enrolls individual customers and provides a coordination arrangement by which participating customers achieve load reductions and are reimbursed by the aggregator. Up to 50 hours of events may be called each year, during the hours of 11 a.m. and 7 p.m.

DRC

The terms of DRC are similar to those of the PG&E AMP program in that each DRC aggregator has a separate bi-lateral forward contract with SCE to provide a specific amount of load reductions for specific months of the program year, in advance (*i.e.*, no month-to-month nominations as for the CBP). The terms of SCE's DRC contracts vary individually with regards to the number of hours and the length of the program event durations. Each contract can also have its own specific trigger requirements, baseline methodologies, and payment terms. There is no requirement to call all DRCs at the same time, only as required under the terms of each contract. The payment arrangements with customers are similar to those of the AMP contracts, with payments for load reductions passed on from the IOU through the aggregator to the customers.

DSP

SDG&E started DSP in 2010 and the program currently contains one DO contract. Up to 50 hours of events may be called each year, including test events, during the hours of 12 a.m. and 6 p.m. Events last a minimum of two hours and a maximum of five hours. The baselines are calculated using the 3-in-10 method.

Program enrollment

Tables ES–1through ES–4 summarize 2010 program enrollment in the DA and DO product types across all six aggregator programs at the three utilities.[1] The first two tables show enrollment in terms of number of customer service accounts (SA IDs), while the second two show enrollment in terms of megawatts (MW) of *on-peak* demand.[2]

The DO product type generally has substantially greater numbers of customer accounts and larger amounts of total on-peak demand than the DA product type.[3] The CBP DO product types at each of the utilities have attracted large numbers of Retail stores. The DRC DO product type has also enrolled mostly Retail stores, as well as substantial total load in the Manufacturing; Wholesale, Transport and other Utilities (primarily water utilities) industry groups.

[1] For the CBP programs, since customers are not assigned to the DA or DO product type until they are nominated for a particular month, enrollments are defined to include all customer accounts that were *nominated* in at least one month during the summer period. A few customer accounts are nominated to a DA product type in some months and to a DO product in others. In those cases, they are classified by their nomination status in the latest month of their enrollment. However, their load impacts for specific events are attributed to the appropriate product type for the month in which the events occurred.

[2] The on-peak demand values represent average hourly usage during typical aggregator event windows (hours ending 13-18) on non-event weekdays. They are provided to illustrate the size, or scale of the total load of enrolled customers. They do not reflect "subscribed demand", which is a measure of potential load impacts.

[3] One PG&E aggregator offered the DA option to several hundred relatively small customer accounts in the San Francisco area.

Table ES–1: Aggregator Program Enrollment – *Day-Ahead Product Types* (*Customer Accounts*)

Industry Type	CBP			Contract-Based	
	PG&E	SCE	SDG&E	AMP	DRC
1. Agriculture, Mining & Construction	29		5	28	24
2. Manufacturing	28	3	26	128	17
3. Wholesale, Transport, other Utilities	48		14	24	47
4. Retail stores	116	74		1	145
5. Offices, Hotels, Health, Services	211	3	80	30	3
6. Schools	26			45	7
7. Entertainment, Other Services, Gov't	90		6	7	2
8. Other/Unknown	13			3	
Total	561	80	131	266	245

Table ES–2: Aggregator Program Enrollment – *Day-Of Product Types* (*Customer Accounts*)

Industry Type	CBP			Contract-Based		
	PG&E	SCE	SDG&E	AMP	DRC	DSP
1. Agriculture, Mining & Construction	35	2		211	51	
2. Manufacturing	25	3	12	120	174	15
3. Wholesale, Transport, other Utilities	32	2	21	113	786	21
4. Retail stores	273	364	196	129	553	24
5. Offices, Hotels, Health, Services	30	40	37	170	103	15
6. Schools	4	1	1	8	44	25
7. Entertainment, Other Services, Gov't	11		47	19	36	4
8. Other/Unknown			1	9		
Total	410	412	315	779	1747	104

Table ES–3: Aggregator Program Enrollment – *Day-Ahead Product Types* (*MW of On-Peak Demand*)

Industry Type	CBP			Contract-Based	
	PG&E	SCE	SDG&E	AMP	DRC
1. Agriculture, Mining & Construction	5.0	0.0	2.5	2.5	3.9
2. Manufacturing	14.2	1.5	12.6	111.1	6.7
3. Wholesale, Transport, other Utilities	5.0	0.0	3.4	5.9	16.6
4. Retail stores	5.4	4.5	0.0	0.1	32.2
5. Offices, Hotels, Health, Services	30.5	1.9	14.1	12.9	0.2
6. Schools	7.8	0.0	0.0	10.6	0.7
7. Entertainment, Other Services, Gov't	5.0	0.0	1.1	6.2	0.5
8. Other/Unknown	1.4	0.0	0.0	0.4	0.0
Total	74.2	7.9	33.6	149.7	60.7

Table ES–4: Aggregator Program Enrollment – *Day-Of Product Types* (*MW of On-Peak Demand*)

Industry Type	CBP			Contract-Based		
	PG&E	SCE	SDG&E	AMP	DRC	DSP
1. Agriculture, Mining & Construction	8.2	0.5	0.0	96.6	8.0	0.0
2. Manufacturing	29.0	0.5	3.0	94.7	112.0	2.8
3. Wholesale, Transport, other Utilities	11.1	0.6	3.6	49.0	105.9	2.5
4. Retail stores	74.4	74.1	34.8	39.6	157.5	3.8
5. Offices, Hotels, Health, Services	26.8	4.6	6.9	96.6	46.6	3.6
6. Schools	10.0	2.2	0.1	19.5	55.4	10.2
7. Entertainment, Other Services, Gov't	5.4	0.0	6.5	12.1	21.3	0.9
8. Other/Unknown	0.0	0.0	0.1	1.5	0.0	0.0
Total	164.8	82.5	55.0	409.6	506.8	23.7

ES.2 Evaluation Methodology

Estimates of total program-level load impacts for each program were developed from the estimated coefficients of individual customer regression equations. These equations were estimated over the summer months for 2010, using individual customer load data for all customer accounts nominated in a month containing an event.

The regression equations were 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—Event indicators, which were invoked when a given customer's product type was called, were interacted with hourly indicator variables to allow estimation of hourly load impacts for each event.

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 industry type and CAISO local capacity area, by adding across customers in any given category, and to analyze the effect of TA/TI and AutoDR participation. Finally, uncertainty-adjusted load impacts are calculated to illustrate the degree of uncertainty that exists around the estimated load impacts.

ES.3 Detailed Study Findings

Summary of ex-post program load impacts

Table ES–5 summarizes estimates of average hourly ex post load impacts for PY 2010 *for the typical DR event* for each of the three utilities' aggregator programs and product types (*e.g., day-ahead* and *day-of* notice). Estimated load impacts for the *day-of* product types are generally greater than for *day-ahead* products, which is consistent with the greater DO enrollment and total load.[4]

[4] For confidentiality reasons, estimated load impacts for PG&E AMP DA are not shown, as only one aggregator offered that product type.

Table ES–5: Aggregator Program Average Hourly Load Impacts (MW) – by Utility and Product Type (2010)

Program	CBP		AMP/DRC/DSP	
Utility/ Program-type	DA	DO	DA	DO
PG&E	11.0	27.9	na	104.9
SCE	0.8	15.4	8.7	113.3
SDG&E	9.6	8.7		7.8

Table ES–6 provides summary indicators of average event-hour load impacts *per nominated customer* for each program and product type. The AMP DO product type has significantly larger kW impacts per customer compared to the other programs.

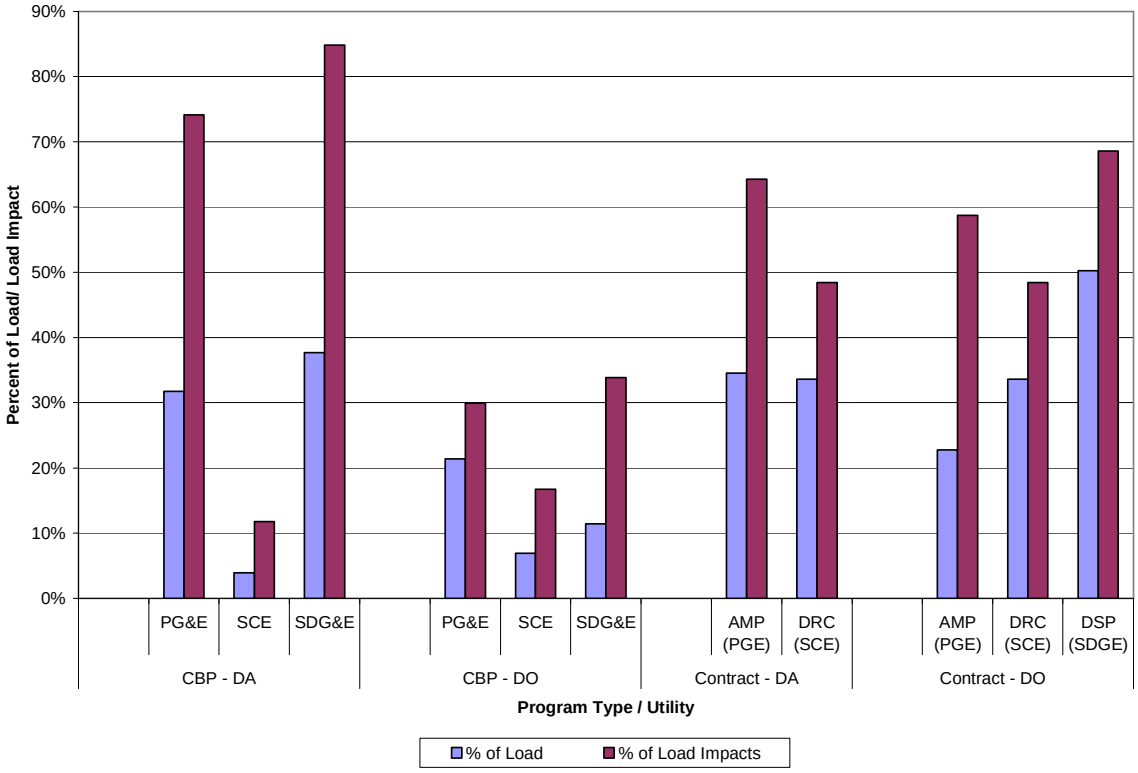
Table ES–6: Average Event-Hour Load Impacts (kW) per Nominated Customer

	DA	DO
PG&E CBP	26	78.2
SCE CBP	11	48.1
SDG&E CBP	80.3	32.6
AMP	na	238.2
DRC	65.9	120.1
DSP		79.8

Figure ES–1 illustrates the concentration of load impacts within the top five percent of customer accounts that account for the largest average load impacts across events. The figure shows the percentages of *load* and *load impacts* that are accounted for by those five percent of customers. In seven of the eleven IOU program/product-types, approximately half or more of the total program load impacts are accounted for by these top five percent of customers.

Note also that the percentage of total load of the top five percent is greater than five percent (with one exception), but always less than the percentage of load impacts. This implies that while some of the concentration of load impacts is due to these top customers being larger than average, they are also relatively more responsive than the average customer in the program/product type.

Figure ES–1: Concentration of Load Impacts – Percent of Load and Load Impacts Accounted for by Top Five Percent of Customer Accounts



Effects of TA/TI and AutoDR

This evaluation included assessments of the load impacts associated with aggregator program customer accounts that participated in TA/TI or AutoDR incentive programs. Two types of analysis were undertaken. First, we report average hourly reference loads and load impacts for those service accounts that have participated in TA/TI or AutoDR. Second, where possible, we compared the load impacts of TA/TI and AutoDR customer accounts in specific business categories to those of non-TA/TI or AutoDR customer accounts in the same business categories (these accounts were sometimes associated with a single customer, such as a large retailer with multiple stores). The latter comparisons were designed as the best opportunity to estimate *incremental* impacts of TA/TI and AutoDR. However, the numbers of customer accounts were quite small, and the load impact comparisons were sometimes inconclusive due to considerable variability.

Summary of ex-ante enrollment and load impacts

Ex ante forecasts of load impacts for each utility and product type were produced based on per-customer load impacts calculated from the ex post evaluation results, and applied to enrollment forecasts provided by the utilities. Figure ES–2 compares enrolled customer accounts in 2010 to enrollment forecasts for 2012. Significant reductions in enrollment are expected for the SCE DRC DO contracts in 2012.

Figure ES–2: Aggregator Program Enrollment (Customer Accounts) – by Utility and Product Type – *2010 and 2012*

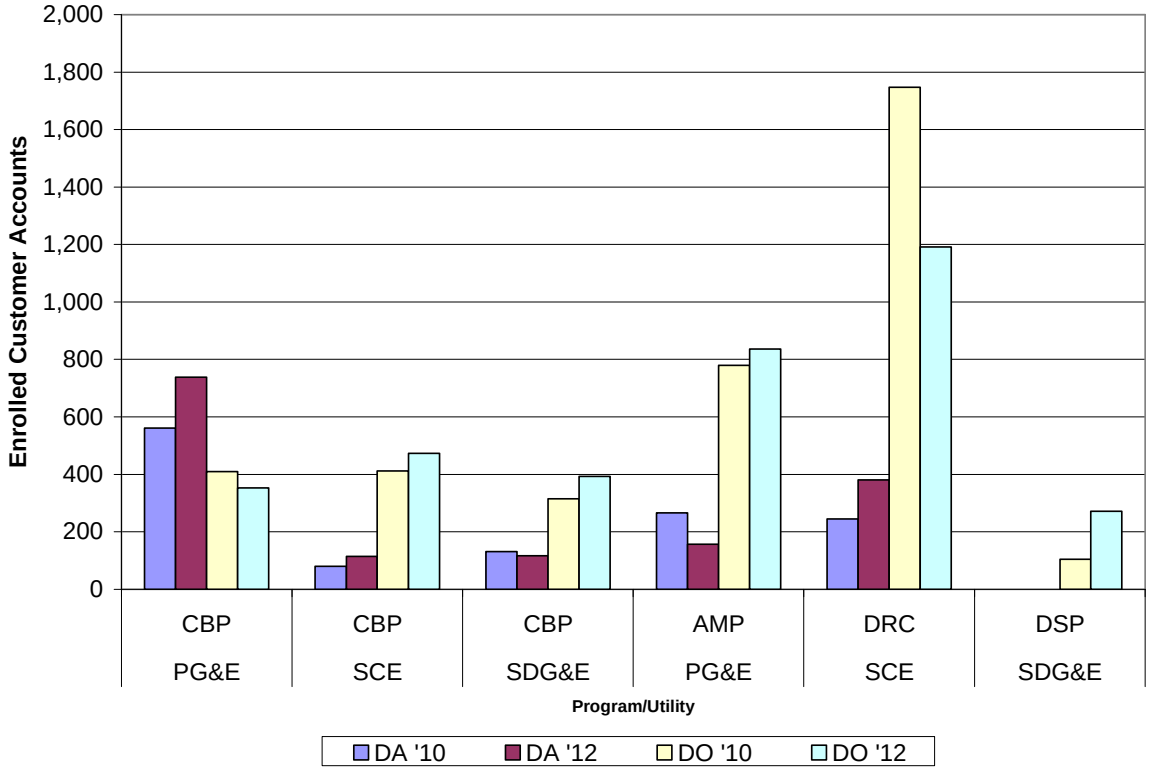
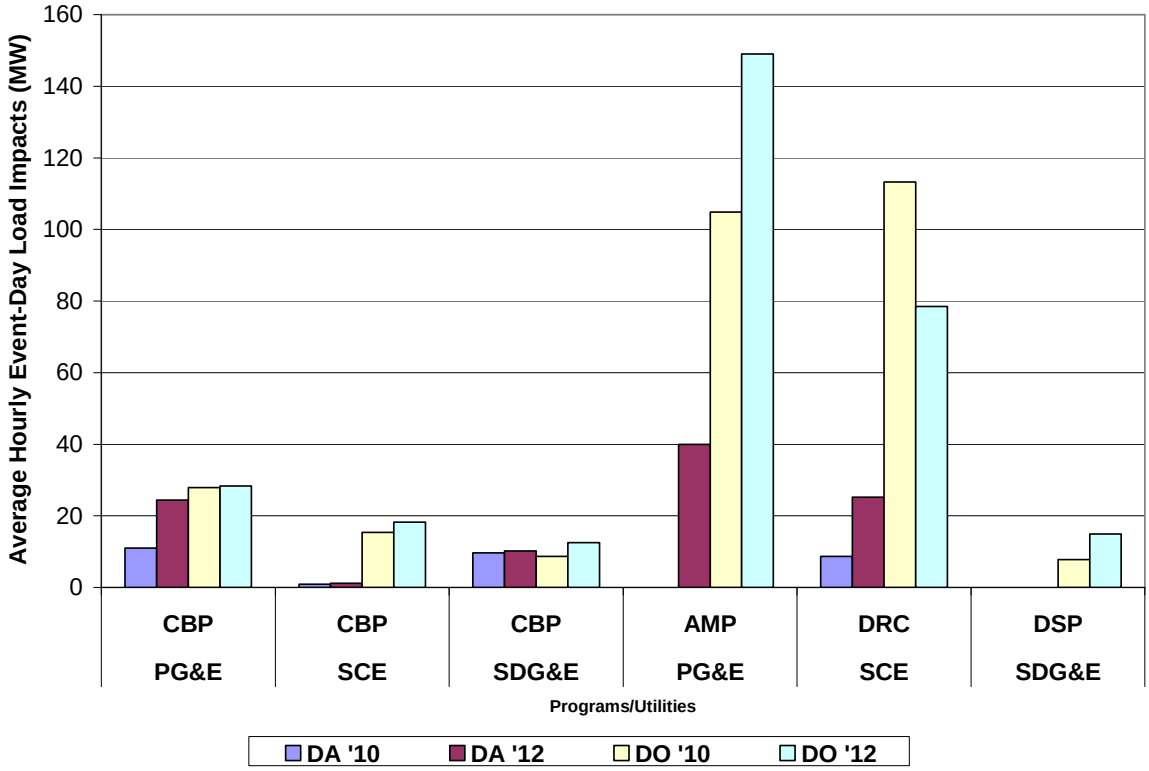


Figure ES–3 compares average hourly load impacts for a typical event day, by utility, program and product type, for 2010, as estimated in the ex-post evaluation, to those projected for 2012 in the 1-in-2 weather scenario of the ex-ante evaluation. Growth in load impacts is expected in the AMP and DSP DO product types, however SCE's DRC load impacts are expected to fall in line with lower enrollments.

Figure ES–3: Average-Hourly Load Impacts (MW) – by Utility and Product Type – *2010 and 2012 (Typical Event Day in 1-in-2 Weather Year)*



ES 4 Conclusions

The customer-level regression equations generally worked well in developing load impact estimates and providing the capability of summing across different customer types to produce load impacts at the program and product-type level, by industry type, and by CAISO local capacity area, as well as for summarizing the concentration of load impacts within the most responsive customers, and for supporting analysis of the effects of AutoDR and TA/TI participation. Changes in monthly enrollments and nominations across the summer period, including those between CBP and the aggregator contract programs presented data management and analysis challenges in conducting the ex post evaluation. However, we believe that the reported results accurately characterize the aggregator program load impacts in 2010 in accordance with the approved Demand Response Load Estimation Protocols for California.

1. Introduction and Purpose of the Study

This report documents the results of an 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 2010. In these programs, aggregators contract 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 such that their aggregated load participates as a single resource 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 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"), and Demand Smart program ("DSP"), operated by SDG&E.

The primary goals of this evaluation study are the following:

1. Estimate the *ex post* load impacts for program year 2010; and
2. Estimate *ex ante* load impacts for the programs for 2011 through 2021

The first goal involved estimating *hourly load impacts* for each 2010 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 sub-groups (*e.g.*, by industry group and CAISO local capacity area), including those customers also participating in the AutoDR and Technical Assistance and Technology Incentives (TA/TI) programs.

The second goal involved combining the information on historical ex post load impacts with utility projections of program enrollment or contracted load nominations to produce *forecasts of load impacts* for each of the programs through 2021.

After this introductory section, Section 2 describes the resources provided by the aggregator programs, including program features and characteristics of the enrolled customer accounts. Section 3 discusses evaluation methodology. Section 4 presents estimates of ex post load impacts. Section 5 describes the ex ante forecasts of enrollment and load impacts. Section 6 discusses validity assessment, and Section 7 offers recommendations.

2. Description of DR Resources Covered in the Study

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

2.1 Description of the aggregator programs

CBP

The CBP program provides month to month capacity payments ($/kW) to aggregators based on the nominated kW load, the specific operating month and program option (DA or DO). Additional energy payments ($/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. Participants 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, 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.

AMP

Under the AMP program, each aggregator operates their resource 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, either with DA or DO trigger. The aggregator enrolls individual customers and provides an arrangement by which participating customers achieve load reductions and are reimbursed by the aggregator. Up to 50 hours of events may be called each year, during the hours of 11 a.m. and 7 p.m.

DRC

The terms of DRC are similar to those of the PG&E AMP program in that each DRC aggregator has a separate bi-lateral forward contract with SCE to provide a specific amount of load reductions for specific months of the program year, in advance (*i.e.*, no month-to-month nominations as for the CBP). The terms of SCE's DRC contracts vary individually with regards to the number of hours and the length of the program event durations. Each contract can also have its own specific trigger requirements, baseline methodologies, and payment terms. There is no requirement to call all DRCs at the same time, only as required under the terms of each contract. The payment arrangements with customers are similar to those of the AMP contracts, with payments for load reductions by the customers passed on from the IOU through the aggregator.

DSP

SDG&E started DSP in 2010 and the program currently contains one DO contract. Up to 50 hours of events may be called each year, including test events, during the hours of 12 a.m. and 6 p.m. Events last a minimum of two hours and a maximum of five hours. The baselines are calculated using the 3-in-10 method.

2.2 Participant characteristics

In order to assess the extent to which load impacts differ by customer type for each aggregator program, the individual IOU enrolled customers are categorized according to seven industry types. Table 2–1 indicates the industry groups and the corresponding North American Industry Classification System (NAICS) codes.[5] The following tables summarize the characteristics of the participating customer accounts in the aggregator programs, including industry type, local capacity area, and usage characteristics.

Table 2-1: Industry Group Definition

Industry Groups	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, Health, Services	51 - 56, 62, 72
6. Schools	61
7. Entertainment, Other Services, Government	71, 81, 92
8. Other/Unknown	

2.2.1 CBP

Tables 2–2 through 2–7 show enrollment by industry type for the DA and DO CBP product types, for PG&E, SCE, and SDG&E respectively. For purposes of these tables, enrollment in CBP DA and DO product types actually represents aggregator *nominations*, because customers are not assigned to DA or DO product types until they are nominated in a particular month. Thus, a few customer accounts may have enrolled in a CBP program but are not included in these tables because they were never nominated by an aggregator during the summer of 2010. Also, some customer accounts may be moved between CBP and either AMP or DRC, or between CBP DA and DO product types. For consistency, the enrollment numbers in the tables are based on nomination conditions as of the month of the last event in which the customer participated. Customers' load impacts for particular events are attributed to the product type for which they were nominated in the month in which the event occurred. The Protocol tables that are provided along with this report show the exact numbers of enrolled, nominated, and called customer accounts for each event, and for the typical event, for each utility and product type.

The first column in the tables reports the number of enrolled customer service accounts (SAIDs) in each IOU's CBP program. The second column, labeled "Average Demand (MW)," represents the sum of enrolled customers' *average hourly usage* over the summer months. The third column, labeled "On-Peak Demand (MW)," shows average hourly demand during non-holiday *summer weekday on-peak periods* (hours ending 13-18) on non-event days. The final two columns indicate the share of On-Peak Demand by industry

[5] SCE provided SIC codes in place of NAICS codes. The industry groups were therefore defined according the following SIC codes: 1 = under 2000; 2 = 2000 to 3999; 3 = 4000 to 5199; 4 = 5200 to 5999; 5 = 6000 to 8199; 6 = 8200 to 8299; 7 = 8300 and higher.

type and the average size (kW) of the customer accounts in a given industry type, measured by average on-peak demand.

The values in the second to last columns in the enrollment tables indicate that the mix of industry groups across utilities and product types varies considerably, with no specific group dominant across all utilities. Of note, retail stores make up a large share of CBP DO enrolled load at each of the utilities, as well as for the DA product type at SCE. For PG&E and SDG&E DA product types, Manufacturing, and Offices, Hotels, Health and Services are important industry groups.

Table 2-2: Enrollment by Industry group – *PG&E CBP DA*

Industry Group	Num. of SAIDs	Average Demand (MW)	On-Peak Demand (MW)	% On-Peak Demand	Average Size (kW)
1. Agriculture, Mining & Construction	29	4.5	5.0	7%	171
2. Manufacturing	28	12.9	14.2	19%	509
3. Wholesale, Transport, other Utilities	48	6.4	5.0	7%	104
4. Retail stores	116	3.9	5.4	7%	46
5. Offices, Hotels, Health, Services	211	24.1	30.5	41%	145
6. Schools	26	7.5	7.8	11%	301
7. Entertainment, Other Services, Gov't	90	3.9	5.0	7%	55
8. Other/Unknown	13	1.0	1.4	2%	105
Total	561	64.2	74.2	100%	132

Table 2-3: Enrollment by Industry group – *PG&E CBP DO*

Industry Group	Num. of SAIDs	Average Demand (MW)	On-Peak Demand (MW)	% On-Peak Demand	Average Size (kW)
1. Agriculture, Mining & Construction	35	7.4	8.2	5%	233
2. Manufacturing	25	27.3	29.0	18%	1,159
3. Wholesale, Transport, other Utilities	32	11.3	11.1	7%	348
4. Retail stores	273	59.0	74.4	45%	273
5. Offices, Hotels, Health, Services	30	21.0	26.8	16%	892
6. Schools	4	8.3	10.0	6%	2,499
7. Entertainment, Other Services, Gov't	11	4.8	5.4	3%	487
8. Other/Unknown		-	-	0%	-
Total	410	139.1	164.8	100%	402

Table 2-4: Enrollment by Industry group – *SCE CBP DA*

Industry Group	Num. of SAIDs	Average Demand (MW)	On-Peak Demand (MW)	% On-Peak Demand	Average Size (kW)
1. Agriculture, Mining & Construction		-	-		-
2. Manufacturing	3	1.4	1.5	19%	506
3. Wholesale, Transport, other Utilities		-	-		-
4. Retail stores	74	2.8	4.5	57%	61
5. Offices, Hotels, Health, Services	3	1.7	1.9	24%	622
6. Schools		-	-		-
7. Entertainment, Other Services, Gov't		-	-		-
8. Other/Unknown		-	-		-
Total	80	5.9	7.9	100%	98

Table 2-5: Enrollment by Industry group – *SCE CBP DO*

Industry Group	Num. of SAIDs	Average Demand (MW)	On-Peak Demand (MW)	% On-Peak Demand	Average Size (kW)
1. Agriculture, Mining & Construction	2	0.4	0.5	1%	263
2. Manufacturing	3	0.5	0.5	1%	154
3. Wholesale, Transport, other Utilities	2	0.7	0.6	1%	311
4. Retail stores	364	57.9	74.1	90%	204
5. Offices, Hotels, Health, Services	40	3.8	4.6	6%	114
6. Schools	1	2.8	2.2	3%	2,211
7. Entertainment, Other Services, Gov't		-	-		-
8. Other/Unknown		-	-		-
Total	412	66.1	82.5	100%	200

Table 2-6: Enrollment by Industry group – *SDG&E CBP DA*

Industry Group	Num. of SAIDs	Average Demand (MW)	On-Peak Demand (MW)	% On-Peak Demand	Average Size (kW)
1. Agriculture, Mining & Construction	5	1.7	2.5	7%	498
2. Manufacturing	26	10.4	12.6	37%	484
3. Wholesale, Transport, other Utilities	14	2.6	3.4	10%	241
4. Retail stores		-	-	0%	-
5. Offices, Hotels, Health, Services	80	10.9	14.1	42%	176
6. Schools		-	-	0%	-
7. Entertainment, Other Services, Gov't	6	1.0	1.1	3%	185
8. Other/Unknown		-	-	0%	-
Total	131	26.5	33.6	100%	257

Table 2-7: Enrollment by Industry group – *SDG&E CBP DO*

Industry Group	Num. of SAIDs	Average Demand (MW)	On-Peak Demand (MW)	% On-Peak Demand	Average Size (kW)
1. Agriculture, Mining & Construction		-	-	0%	-
2. Manufacturing	12	2.6	3.0	5%	251
3. Wholesale, Transport, other Utilities	21	4.0	3.6	7%	172
4. Retail stores	196	29.3	34.8	63%	178
5. Offices, Hotels, Health, Services	37	5.7	6.9	13%	187
6. Schools	1	0.1	0.1	0%	139
7. Entertainment, Other Services, Gov't	47	5.7	6.5	12%	137
8. Other/Unknown	1	0.0	0.1	0%	53
Total	315	47.5	55.0	100%	175

Tables 2–8 through 2–11 show CBP DA and DO enrollment by CAISO Local Capacity Area (LCA) for PG&E and SCE.[6]

[6] The entire SDG&E service area is considered to be one local capacity area.

Table 2-8: Enrollment by Local Capacity Area – *PG&E CBP DA*

LCA	Num. of SAIDs	Average Demand (MW)	On-Peak Demand (MW)	% On-Peak Demand	Average Size (kW)
1. Greater Bay Area	477	44.2	53.9	73%	113
2. Greater Fresno	28	5.1	5.0	7%	179
3. Humboldt	1	0.0	0.0	0%	39
4. Kern	7	0.7	0.6	1%	92
5. Northern Coast	5	0.3	0.4	1%	78
6. Sierra	4	0.2	0.3	0%	86
7. Stockton	4	0.2	0.3	0%	67
8. Not in any LCA	35	13.6	13.6	18%	389
Total	561	64.2	74.2	100%	132

Table 2-9: Enrollment by Local Capacity Area – *PG&E CBP DO*

LCA	Num. of SAIDs	Average Demand (MW)	On-Peak Demand (MW)	% On-Peak Demand	Average Size (kW)
1. Greater Bay Area	183	61.0	74.0	45%	404
2. Greater Fresno	60	12.5	14.9	9%	248
3. Humboldt	2	0.9	1.3	1%	672
4. Kern	14	4.1	5.0	3%	358
5. Northern Coast	35	8.3	10.4	6%	298
6. Sierra	24	8.1	9.6	6%	400
7. Stockton	15	5.1	6.4	4%	429
8. Not in any LCA	77	39.1	43.1	26%	560
Total	410	139.1	164.8	100%	402

Table 2-10: Enrollment by Local Capacity Area – *SCE CBP DA*

LCA	Num. of SAIDs	Average Demand (MW)	On-Peak Demand (MW)	% On-Peak Demand	Average Size (kW)
1. LA Basin	63	4.3	5.8	74%	92
2. Outside LA Basin	5	0.2	0.4	5%	72
3. Ventura	12	1.4	1.7	21%	141
Total	80	5.9	7.9	100%	98

Table 2-11: Enrollment by Local Capacity Area – *SCE CBP DO*

LCA	Num. of SAIDs	Average Demand (MW)	On-Peak Demand (MW)	% On-Peak Demand	Average Size (kW)
1. LA Basin	331	52.9	65.6	79%	198
2. Outside LA Basin	23	4.2	5.4	7%	236
3. Ventura	58	8.9	11.5	14%	198
Total	412	66.1	82.5	100%	200

2.2.2 AMP, DRC and DSP

Tables 2–12 through 2–20 show enrollment information for the DA and DO product types of PG&E's AMP, SCE's DRC, and SDG&E's DSP programs.

PG&E's AMP DA product type is largely dominated by manufacturing customers, while DO enrollment is spread over several industry types.

SCE's DRC DA contracts have significant participation by customers in the Wholesale, Transportation and other Utilities; Manufacturing; and Retail stores industry groups. The DRC DO product type has over seven times the enrollment of DRC DA, with the same industry groups more evenly represented, along with Schools and Offices.

Enrollment in SDG&E's DSP, which offers only the DO product type, is spread over several industry groups, with the largest percentage in Schools.

Table 2-12: Enrollment by Industry Group – *PG&E AMP DA*

Industry Group	Num. of SAIDs	Average Demand (MW)	On-Peak Demand (MW)	% On-Peak Demand	Average Size (kW)
1. Agriculture, Mining & Construction	28	2.2	2.5	2%	88
2. Manufacturing	128	105.9	111.1	74%	868
3. Wholesale, Transport, other Utilities	24	5.4	5.9	4%	248
4. Retail stores	1	0.1	0.1	0%	115
5. Offices, Hotels, Health, Services	30	10.4	12.9	9%	430
6. Schools	45	7.8	10.6	7%	235
7. Entertainment, Other Services, Gov't	7	5.7	6.2	4%	893
8. Other/Unknown	3	0.3	0.4	0%	127
Total	266	137.7	149.7	100%	563

Table 2-13: Enrollment by Industry Group – *PG&E AMP DO*

Industry Group	Num. of SAIDs	Average Demand (MW)	On-Peak Demand (MW)	% On-Peak Demand	Average Size (kW)
1. Agriculture, Mining & Construction	211	91.1	96.6	24%	458
2. Manufacturing	120	88.0	94.7	23%	789
3. Wholesale, Transport, other Utilities	113	48.3	49.0	12%	433
4. Retail stores	129	34.5	39.6	10%	307
5. Offices, Hotels, Health, Services	170	74.7	96.6	24%	568
6. Schools	8	18.2	19.5	5%	2,443
7. Entertainment, Other Services, Gov't	19	10.2	12.1	3%	635
8. Other/Unknown	9	1.4	1.5	0%	168
Total	779	366.6	409.6	100%	526

Table 2-14: Enrollment by Local Capacity Area – *PG&E AMP DA*

LCA	Num. of SAIDs	Average Demand (MW)	On-Peak Demand (MW)	% On-Peak Demand	Average Size (kW)
1. Greater Bay Area	82	37.9	43.0	29%	524
2. Greater Fresno	37	17.2	18.7	12%	505
3. Humboldt		-	-	0%	-
4. Kern		-	-	0%	-
5. Northern Coast	24	6.2	7.3	5%	303
6. Sierra	28	5.1	5.9	4%	211
7. Stockton	9	1.3	1.7	1%	187
8. Not in any LCA	86	70.0	73.2	49%	851
Total	266	137.7	149.7	100%	563

Table 2-15: Enrollment by Local Capacity Area – *PG&E AMP DO*

LCA	Num. of SAIDs	Average Demand (MW)	On-Peak Demand (MW)	% On-Peak Demand	Average Size (kW)
1. Greater Bay Area	246	111.1	137.6	34%	559
2. Greater Fresno	194	60.2	64.4	16%	332
3. Humboldt	8	1.4	1.5	0%	187
4. Kern	62	56.8	58.1	14%	937
5. Northern Coast	48	10.1	12.1	3%	253
6. Sierra	27	10.2	11.5	3%	424
7. Stockton	28	11.3	12.6	3%	451
8. Not in any LCA	166	105.6	111.8	27%	673
Total	779	366.6	409.6	100%	526

Table 2-16: Enrollment by Industry group – *SCE DRC DA*

Industry Group	Num. of SAIDs	Average Demand (MW)	On-Peak Demand (MW)	% On-Peak Demand	Average Size (kW)
1. Agriculture, Mining & Construction	24	3.9	3.9	6%	164
2. Manufacturing	17	5.9	6.7	11%	397
3. Wholesale, Transport, other Utilities	47	17.1	16.6	27%	352
4. Retail stores	145	21.2	32.2	53%	222
5. Offices, Hotels, Health, Services	3	0.1	0.2	0%	52
6. Schools	7	0.4	0.7	1%	99
7. Entertainment, Other Services, Gov't	2	0.3	0.5	1%	238
8. Other/Unknown		-	-	0%	-
Total	245	49.0	60.7	100%	248

Table 2-17: Enrollment by Industry group – *SCE DRC DO*

Industry Group	Num. of SAIDs	Average Demand (MW)	On-Peak Demand (MW)	% On-Peak Demand	Average Size (kW)
1. Agriculture, Mining & Construction	51	7.8	8.0	2%	158
2. Manufacturing	174	107.7	112.0	22%	644
3. Wholesale, Transport, other Utilities	786	115.3	105.9	21%	135
4. Retail stores	553	128.3	157.5	31%	285
5. Offices, Hotels, Health, Services	103	41.0	46.6	9%	453
6. Schools	44	48.2	55.4	11%	1,258
7. Entertainment, Other Services, Gov't	36	18.7	21.3	4%	592
8. Other/Unknown		-	-	0%	-
Total	1,747	466.9	506.8	100%	290

Table 2-18: Enrollment by LCA – *SCE DRC DA*

LCA	Num. of SAIDs	Average Demand (MW)	On-Peak Demand (MW)	% On-Peak Demand	Average Size (kW)
1. LA Basin	198	43.7	53.4	88%	270
2. Outside LA Basin	11	1.0	1.6	3%	143
3. Ventura	36	4.3	5.7	9%	160
Total	245	49.0	60.7	100%	248

Table 2-19: Enrollment by LCA – *SCE DRC DO*

LCA	Num. of SAIDs	Average Demand (MW)	On-Peak Demand (MW)	% On-Peak Demand	Average Size (kW)
1. LA Basin	1,341	364.7	400.0	79%	298
2. Outside LA Basin	216	25.1	24.8	5%	115
3. Ventura	190	77.0	82.0	16%	431
Total	1,747	466.9	506.8	100%	290

Table 2-20: Enrollment by Industry group – SDG&E DSP (DO)

Industry Group	Num. of SAIDs	Average Demand (MW)	On-Peak Demand (MW)	% On-Peak Demand	Average Size (kW)
1. Agriculture, Mining & Construction		-	-	0%	-
2. Manufacturing	15	2.4	2.8	12%	184
3. Wholesale, Transport, other Utilities	21	3.3	2.5	10%	118
4. Retail stores	24	3.3	3.8	16%	160
5. Offices, Hotels, Health, Services	15	2.9	3.6	15%	237
6. Schools	25	7.9	10.2	43%	408
7. Entertainment, Other Services, Gov't	4	0.7	0.9	4%	216
8. Other/Unknown		-	-	0%	-
Total	104	20.4	23.7	100%	228

2.3 Program events

2.3.1 CBP

PG&E called eleven CBP events in 2010, as shown in Table 2–21. A mixture of *day-ahead* and *day-of* program-type events were called, for the hours indicated in the table. Monthly nominations for each product type are shown in the last column. For each event, the table also shows which Product (characterized by the number of hours for which events can be called, e.g., 1 to 4, or 2 to 6) was called, and how many aggregators were providing that Product. Monthly aggregated MW nominations for each product type across all aggregators that were available for each event are shown in the last column.

Throughout the summer, six PG&E aggregators provided a DA 1 – 4 CBP product. Their monthly nominations totaled 22.9 MW in July, 14.1 MW in August, and 11.4MW in September. One aggregator offered a DO 1 – 4 product, while five aggregators offered DO 2 – 6 products. These products nominated a combined 23.3 MW in June, 34.6 MW in July (including a seventh aggregator), 27.7 MW in August, and 30.5 MW in September (including a seventh aggregator). All Products were called at least once starting in July, with some twice or three times in August and September.

Table 2-21: PG&E CBP Events – 2010

Event #	Date	Type	Product	Aggregators		Hours Ending	Nominations (MW)	
				DA	DO		DA	DO
1	June 28, 2010	DO	1-4; 2-6		5	16 - 17		23.3
2	July 15, 2010	DO	1-4; 2-6		7	15 - 18		34.6
3	July 16, 2010	DA	1-4	6		15 - 17	22.9	
4	August 16, 2010	DA	1-4	6		15 - 17	14.1	
5	August 23, 2010	DO	2-6		1	14 - 19		7.0
		DO	1-4		5	15 - 18		20.7
6	August 24, 2010	DA	1-4	6		15 - 18	14.1	
		DO	2-6		1	14 - 19		7.0
		DO	1-4		5	15 - 18		20.7
7	August 25, 2010	DA	1-4	6		15 - 18	14.1	
		DO	2-6		1	13 - 18		7.0
		DO	1-4		5	14 - 17		20.7
8	September 2, 2010	DA	1-4	6		16 - 17	11.4	
9	September 27, 2010	DO	2-6		1	14 - 19		7.3
		DO	1-4		6	15 - 18		23.2
10	September 28, 2010	DA	1-4	6		16 - 17	11.4	
		DO	2-6		1	14 - 19		7.3
		DO	1-4		6	15 - 18		23.2
11	September 29, 2010	DA	1-4	6		16 - 17	11.4	

SCE called nineteen CBP events, as shown in Table 2–22. A variety of combinations of DA and DO product types were called, including a mixture of event-length products. Two SCE aggregators provided the DA 1-4 product, and one the DA 2 – 6 product. Their combined monthly nominations totaled between 4.5 and 9 MW in July through September. Three aggregators offered DO 1 – 4 products, and two offered DO 2 – 6 products. The combined nominations totaled 70 MW in July, and 93.7 MW in August and September.

Table 2-22: SCE CBP Events – 2010

Event #	Date	Product Type	Product	Aggregators DA	Aggregators DO	Hours Ending Start	Hours Ending End	Nominations (MW) DA	Nominations (MW) DO
1	July 14, 2010	DO	1-4; 2-6		5	16	17		14.7
2	July 15, 2010	DO	1-4; 2-6		5	15	18		14.7
3	July 16, 2010	DA	1-4	2		15	18	2.2	
			2-6	1		14	18	0.1	
		DO	1-4		3	15	18		3.5
			2-6		2	15	19		11.2
4	July 19, 2010	DA	1-4; 2-6	3		16	17	2.2	
5	August 16, 2010	DA	1-4; 2-6	3		15	17	2.2	
6	August 17, 2010	DA	1-4; 2-6	3		16	17	2.2	
7	August 23, 2010	DA	1-4; 2-6	3		16	17	2.2	
8	August 24, 2010	DA	1-4	2		14	17	2.2	
			2-6	1		13	18	0.1	
		DO	1-4		3	14	17		3.2
			2-6		2	14	19		13.4
9	August 25, 2010	DA	1-4	2		14	17	2.2	
			2-6	1		13	18	0.1	
		DO	1-4		3	14	17		3.2
			2-6		2	13	18		13.4
10	August 26, 2010	DA	1-4	2		15	18	2.2	
			2-6	1		15	18	0.1	
		DO	1-4		3	16	19		3.2
			2-6		2	15	19		13.4
11	August 27, 2010	DA	1-4	2		16	17	2.2	
12	September 1, 2010	DA	1-4; 2-6	3		16	17	2.2	
13	September 2, 2010	DA	1-4; 2-6	3		16	17	2.2	
14	September 3, 2010	DA	1-4; 2-6	3		16	17	2.2	
15	September 24, 2010	DO	1-4		4	19	19		5.0
16	September 27, 2010	DA	1-4; 2-6	3		15	18	2.2	
		DO	1-4		4	15	18		5.0
			2-6		2	13	18		12.3
17	September 28, 2010	DA	1-4; 2-6	3		15	17	2.2	
		DO	1-4		4	14	17		5.0
			2-6		2	14	19		12.3
18	September 29, 2010	DA	1-4; 2-6	3		16	17	2.2	
19	September 30, 2010	DA	1-4; 2-6	3		16	17	2.2	

SDG&E called thirteen CBP events, as shown in Table 2–23. Events were called for varying time periods, as indicated in the table. Three SDG&E aggregators provided the DA 1-4 product. Their combined monthly nominations totaled 10.7 MW in July, 9 MW in August, and 10.4 in September. Five aggregators offered DO 1 – 4 products, and two offered DO 2 – 6 products. Their combined nominations totaled 20.5 MW in July, 14.1

MW in August, and 10.2 in September.[7] For the August 20 event, one DA aggregator did not receive the event notice.

Table 2-23: SDG&E CBP Events – 2010

Event	Date	Number of Aggregator/Contracts			Event Hours by Contract Type (Hours Ending)			Nominations (MW)	
		DA	DO 4	DO 6	DA	DO 4	DO 6	DA	DO
1	July 14, 2010		5	2		14-17	14-17		20.5
2	July 15, 2010		5	2		14-17	14-17		20.5
3	July 16, 2010	3	5	2	14-17	14-17	14-17	10.7	20.5
4	August 18, 2010		5	2		14-17	14-17		14.1
5	August 19, 2010	3	5	2	14-17	14-17	14-17	9.0	14.1
6	August 20, 2010	2*			14-17			2.1	
7	August 23, 2010		5	2		14-17	14-17		14.1
8	August 24, 2010	3	5	2	14-17	14-17	14-17	9.0	14.1
9	August 25, 2010[C]	3	5	2	14-17	14-17	14-17	9.0	14.1
10	August 26, 2010[C]	3	5	2	14-17	14-17	14-17	9.0	14.1
11	September 27, 2010[C]		4	2		15-18	14-19		10.2
12	September 28, 2010[C]	3	4	2	15-18	15-18	14-19	10.4	10.2
13	September 29, 2010		4	2		17-18	17-18		10.2

* One aggregator did not receive event notification.
[C] CPP event day

2.3.2 AMP, DRC and DSP

Tables 2–24 through 2–26 list the events for PG&E's AMP, SCE's DRC, and SDG&E's DSP programs, respectively. One PG&E AMP DA aggregator committed 44 MW, while four DO aggregators committed 123 MW. Two AMP events were called, the first being a test event in July, and the second a re-test for two of the aggregators in August. Both test days coincided with CBP event days.

Table 2-24: AMP (PG&E) Events (Test) – 2010

Event #	Date	Type	Aggregators		Hours Ending	Commitment (MW)	
			DA	DO		DA	DO
1	July 16, 2010	DA	1		16 - 17	44.0	
		DO		4	16 - 17		123.2
2	August 25, 2010	DO[1]		2	16 - 17		51.2

[1] Re-test

[7] Unique to SDG&E, customers enrolled in critical-peak pricing (CPP) may also participate in the day-of CBP product type. The table indicates which CBP DO events were also CPP events.

Two SCE DRC DA aggregators committed 45 MW in July and 50 MW in August, while three DO aggregators committed 144 MW in July, and four committed 172 MW in August. SCE called a test event for five of the DRC aggregators in July, and six aggregators in August, as shown. The July test day was not coincident with any SCE CBP event day, but the August test was.

Table 2-25: DRC (SCE) Events – 2010

Event #	Date	Type	Aggregators		Hours	Contract (MW)	
			DA	DO	Ending	DA	DO
1	July 28, 2010	DA	2		14 - 16	45	
		DO		3	14 - 16		144
	August 25, 2010	DA	2		15 - 17	50	
2		DO		4	14 - 16		172

SDG&E called ten DSP events, as indicated in Table 2–26[8]. Interestingly, all three utilities called AMP, DRC, and DSP events on the same day, August 25, 2010, which was also a CBP event day for all three IOUs.

Table 2-26: DSP (SDG&E) Events – 2010

Event	Date	Hours Ending
1	July 14, 2010	14-17
2	July 15, 2010	14-17
3	July 16, 2010	14-18
4	August 17, 2010	14-18
5	August 18, 2010	14-18
6	August 19, 2010	14-18
7	August 23, 2010	14-18
8	August 24, 2010	15-16
9	August 25, 2010	15-16
10	September 27, 2010	15-18

3. Study Methodology

3.1 Overview and questions addressed

Direct estimates of total program-level ex post load impacts for each program were developed from the coefficients of individual customer regression equations. These equations were estimated over the summer months for 2010, primarily by using individual data for all customer accounts enrolled in each program. In some cases, aggregate equations were also estimated, for diagnostic purposes and cross checking of results.

[8] The contract amount for DSP is considered confidential information because it involves only one aggregator.

The regression equations were 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.*, hourly CDH)
- Event indicators—Event indicators, combined with information on which customer accounts were nominated in each month for a product type (e.g., day-of program for two to four hours), and which product types were called for each event, were interacted with hourly indicator variables to allow estimation of hourly load impacts for each event.

The resulting equations provide the capability of simulating hourly reference load profiles for various day-types and weather conditions, as well as measuring hourly load changes on event days. The models use the *level* of hourly usage as the dependent variable and a separate equation is estimated for each enrolled and nominated customer. As a result, the coefficients on the event day/hour variables are direct estimates of the ex post load impacts. For example, a CBP hour-14 coefficient of -100 for Event 1 means that the customer reduced load by 100 kWh during hour 14 of that event day relative to its normal usage in that hour. Weekends and holidays were excluded from the estimation database.[9] Finally, uncertainty-adjusted load impacts were calculated to illustrate the degree of statistical confidence that exists around the estimated load impacts.

3.2 Primary regression equation specifications

Ex post load impacts were estimated using customer-level hourly data from May through September. The primary regression model is as follows:

$$Q_t = a + \sum_{Evt=1}^{E}\sum_{i=1}^{24}(b_{i,Evt}^{AGG} \times h_{i,t} \times AGG_t) + b^{MornLoad} \times MornLoad_t + \sum_{i=1}^{24}(b_i^{CDH} \times h_{i,t} \times CDH_t)$$
$$+ \sum_{i=2}^{24}(b_i^{MON} \times h_{i,t} \times MON_t) + \sum_{i=2}^{24}(b_i^{FRI} \times h_{i,t} \times FRI_t) + \sum_{i=2}^{24}(b_i^{h} \times h_{i,t}) + \sum_{i=2}^{5}(b_i^{DTYPE} \times DTYPE_{i,t})$$
$$+ \sum_{i=6}^{10}(b_i^{MONTH} \times MONTH_{i,t}) + e_t$$

where:
Q_t represents the demand in hour t for a customer nominated in the month of the event date;
the b's are estimated parameters;
$h_{i,t}$ is a dummy variable for hour i;
AGG_t is an indicator variable for program event days;
CDH_t is cooling degree hours;[10]

[9] 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.

[10] Cooling degree hours (CDH) was defined as MAX[0, Temperature – 50], where Temperature is the hourly temperature in degrees Fahrenheit. Customer-specific CDH values are calculated using data from the most appropriate weather station.

E is the number of event days that occurred during the program year;
$MornLoad_t$ is a variable equal to the average of the day's load in hours 1 through 10;
MON_t is a dummy variable for Monday;
FRI_t is a dummy variable for Friday;
$DTYPE_{i,t}$ is a series of dummy variables for each day of the week;
$MONTH_{i,t}$ is a series of dummy variables for each month; and
e_t is the error term.

The "morning load" variable was used in lieu of a more formal autoregressive structure in order to adjust the model to account for load levels on a particular day, particularly for customers whose daily loads vary substantially for no observable reason (such as more or less intensive than average operations on the part of manufacturing customers). Because of the autoregressive nature of the morning load variable, no further correction for serial correlation was performed in these models.

Separate models were estimated for each customer. The estimated load impacts, in the form of hourly event coefficients, were aggregated across customers to arrive at program-level load impacts, and results by industry group and LCA. Overall program-level and aggregator-level regressions were also estimated in some cases, primarily to provide consistency checks for the individual customer results.

3.3 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. Therefore, we base the uncertainty-adjusted load impacts on the variances associated with the estimated load impacts.

Specifically, we add the variances of the estimated load impacts across the customers who were nominated for the event in question. These aggregations are performed at either the program level, by industry group, or by LCA. 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. Detailed Study Findings

This section describes the results of our estimation of *aggregate* event-day load impacts for each utility, and for the DA and DO product types of each aggregator program (in addition, the Protocol table spreadsheet provided in conjunction with this report includes estimates of load impacts *per-enrolled customer*). For each program and product type, we summarize the load impacts estimated for 2010 at three levels of aggregation. First, using the metric of *average hourly load impacts,* we summarize loads and load impacts for each event, and for the average, or typical event, as well as the distribution of load impacts for the typical event across industry types and local capacity areas (for PG&E and SCE).

In order to provide consistent and comparable values across events, the average hourly load impact values *for each event* are calculated over common hours to any different products defined by length of event (*e.g.*, 1 – 4 or 2 – 6 hours). If, for example, the DO 1 – 4 hour product is called for hours-ending 15 – 17, while the 2 – 6 hour product is called for hours-ending 14 – 19, then the average hourly DO load impact value for that event would be calculated across the common hours of HE 15 – 17. Load impact values for any remaining hours are included in the reporting described below. In addition, the average, or *typical* event is defined so as to represent the most common event. In cases where all aggregators and products were called for each event, then a straight average across events is used. However, in cases where only some aggregators or products were called, then those events were excluded from the average. The definition of the typical event is provided for each program. Also provided are the nominated load impacts (CBP) or contract amounts (AMP, DRC, and DSP) for each event, where the values are consistent with those reported in the event tables in Section 2.

Second, we report average event-hour load impacts *for each hour that was included in the event window for any event*, where the average is computed across only those customer accounts and days for which an event occurred.[11] These tables also include load impacts *per called customer*. Finally, we provide overall results for the typical event at the level of the DA and DO product types in tables using the format required by the Protocols. These tables show estimated hourly program-level reference loads, observed loads, and estimated load impacts for the typical event, as well as uncertainty-adjusted load impacts at different probability levels.[12] Complete sets of tables are provided in an appendix. Hourly load impact results are also illustrated in figures.

We begin with CBP at each of the three utilities, and then turn to AMP (PG&E), DRC (SCE), and DSP (SDG&E).

4.1 CBP – PG&E

4.1.1 Summary load impacts

Tables 4–1 and 4–2 show average hourly estimated *reference load*, *observed load*, *load impacts* and *percentage load impacts* for the DA and DO product types, for each of PG&E's CBP events, and for averages across each of the respective events. The average hourly DA load impact was 11.0 MW[13], while the DO load impact averaged 27.9 MW. Load impacts for both product types compare reasonably favorably to the nominated amounts.

[11] This distinction is necessary for the aggregator programs because of the many different sets of hours that were called for some of the product types. This is in contrast, for example, to the utilities' critical-peak pricing rates, in which the event hours are the same for each event.

[12] In these tables, average values of loads and load impacts for all 24 hours represent averages for those hours over all event days included in the definition of an average event, regardless of how many event days each hour was included in an event (*e.g.*, hour-ending 14 may have been within the event window for only 2 of 8 events for a given program).

[13] One DA aggregator that nominated several hundred relatively small customer accounts in July and August, nominated less than one hundred in September, hence the difference in SAIDs called for the September events.

Table 4-1: Average Hourly Load Impacts by Event – *PG&E CBP DA*

Event	Date	Day of Week	SAIDs Called	Estimated Reference Load (MW)	Observed Load (MW)	Estimated Load Impact (MW)	% Load Impact	Nominated Load Impact (MW)
1	June 28, 2010	Monday		-	-	-		
2	July 15, 2010	Thursday		-	-	-		
3	July 16, 2010	Friday	503	68.8	57.1	11.7	17%	22.9
4	August 16, 2010	Monday	535	71.4	57.8	13.6	19%	14.1
5	August 23, 2010	Monday		-	-	-		
6	August 24, 2010	Tuesday	536	80.5	72.4	8.1	10%	14.1
7	August 25, 2010	Wednesday	536	79.4	69.8	9.6	12%	14.1
8	September 2, 2010	Thursday	158	44.4	32.7	11.8	26%	11.4
9	September 27, 2010	Monday		-	-	-		
10	September 28, 2010	Tuesday	158	46.9	34.7	12.2	26%	11.4
11	September 29, 2010	Wednesday	158	44.7	34.4	10.3	23%	11.4
	Average		369	62.3	51.3	11.0	19%	
	Standard Deviation			16.4	17.2	1.8	6%	

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

Event	Date	Day of Week	SAIDs Called	Estimated Reference Load (MW)	Observed Load (MW)	Estimated Load Impact (MW)	% Load Impact	Nominated Load Impact (MW)
1	June 28, 2010	Monday	310	112.5	90.9	21.6	19%	23.3
2	July 15, 2010	Thursday	352	161.9	132.9	29.0	18%	34.6
3	July 16, 2010	Friday		-	-	-		
4	August 16, 2010	Monday		-	-	-		
5	August 23, 2010	Monday	357	155.4	126.4	29.0	19%	27.7
6	August 24, 2010	Tuesday	357	165.5	135.5	30.0	18%	27.7
7	August 25, 2010	Wednesday	357	165.8	134.6	31.1	19%	27.7
8	September 2, 2010	Thursday		-	-	-		
9	September 27, 2010	Monday	372	153.7	127.6	26.0	17%	30.5
10	September 28, 2010	Tuesday	372	159.2	130.8	28.4	18%	30.5
11	September 29, 2010	Wednesday		-	-	-		
	Average		354	153.4	125.5	27.9	18%	
	Standard Deviation			18.6	15.6	3.2	1%	

Tables 4–3 and 4–4 report the distributions of load impacts for the typical event by industry type. The Manufacturing industry group accounted for the largest share of DA load impacts, while retail stores provided the largest share of DO load impacts.

Table 4-3: Average Hourly Load Impacts by Industry Group – *PG&E CBP DA*

Industry Group	SAIDs Called	Estimated Reference Load (MW)	Observed Load (MW)	Estimated Load Impact (MW)	% Load Impact
1. Agriculture, Mining & Construction	22	4.0	1.7	2.3	57%
2. Manufacturing	22	13.4	8.4	4.9	37%
3. Wholesale, Transport, other Utilities	31	3.5	2.2	1.3	38%
4. Retail stores	86	5.1	4.3	0.9	17%
5. Offices, Hotels, Health, Services	133	25.3	24.0	1.3	5%
6. Schools	15	6.0	5.8	0.2	3%
7. Entertainment, Other Services, Gov't	54	4.2	4.0	0.2	4%
8. Other/Unknown	7	0.8	0.8	0.0	2%
Total	369	62.3	51.3	11.0	18%

Table 4-4: Average Hourly Load Impacts by Industry Group – *PG&E CBP DO*

Industry Group	SAIDs Called	Estimated Reference Load (MW)	Observed Load (MW)	Estimated Load Impact (MW)	% Load Impact
1. Agriculture, Mining & Construction	19	6.5	3.0	3.5	53%
2. Manufacturing	18	20.1	17.9	2.2	11%
3. Wholesale, Transport, other Utilities	25	8.4	4.7	3.7	44%
4. Retail stores	252	82.5	68.8	13.7	17%
5. Offices, Hotels, Health, Services	27	25.0	22.8	2.2	9%
6. Schools	3	8.1	7.0	1.1	14%
7. Entertainment, Other Services, Gov't	10	2.8	1.3	1.5	54%
8. Other/Unknown					
Total	354	153.4	125.5	27.9	18%

Tables 4–5 and 4–6 show average hourly load impacts for DA and DO by LCA. The largest shares for both product types were in the Greater Bay Area and Greater Fresno Area.

Table 4-5: Average Hourly Load Impacts by LCA – *PG&E CBP DA*

LCA	SAIDs Called	Estimated Reference Load (MW)	Observed Load (MW)	Estimated Load Impact (MW)	% Load Impact
1. Greater Bay Area	302	43.3	37.2	6.1	14%
2. Greater Fresno	22	4.2	1.9	2.3	54%
3. Humboldt	1	0.0	0.0	0.0	3%
4. Kern	4	0.3	0.1	0.2	80%
5. Northern Coast	4	0.4	0.3	0.1	31%
6. Sierra	4	0.4	0.2	0.2	42%
7. Stockton	4	0.3	0.2	0.1	23%
8. Not in any LCA	29	13.4	11.3	2.1	16%
Total	369	62.3	51.3	11.0	18%

Table 4-6: Average Hourly Load Impacts by LCA – *PG&E CBP DO*

LCA	SAIDs Called	Estimated Reference Load (MW)	Observed Load (MW)	Estimated Load Impact (MW)	% Load Impact
1. Greater Bay Area	166	72.0	61.7	10.4	14%
2. Greater Fresno	43	14.5	9.2	5.2	36%
3. Humboldt	2	1.2	1.2	0.1	4%
4. Kern	12	4.6	4.1	0.5	11%
5. Northern Coast	31	11.3	9.7	1.6	14%
6. Sierra	20	7.5	6.2	1.4	18%
7. Stockton	13	7.3	5.2	2.1	29%
8. Not in any LCA	67	35.0	28.3	6.7	19%
Total	354	153.4	125.5	27.9	18%

4.1.2 Hourly load impacts

Tables 4–7 and 4–8 show average event-hour load impacts for the hours that were included in any event. Average event-hour load impacts for DA were greatest for HE 16 and 17, where the load impacts were 18 percent of the reference load, and load impacts per called customer were about 30 kW.

For DO, average event-hour load impacts for HE 15 – 17 were nearly constant, at about 28 MW, or about 18 percent of the reference load. Average event-hour load impacts per called customer were about 80 kW.

Table 4-7: Average Event-Hour Load Impacts – *PG&E CBP DA*

Hour Ending	Number of SAIDs Called	Estimated Reference Load (MW)	Observed Load (MW)	Estimated Load Impact (MW)	Weighted Average Temp (°F)	# of Events this Hour is included	Load Impact per Called Customer (kW)	% Load Impact
15	519	77.6	68.0	9.6	88	3	18.4	12%
16	366	63.4	51.9	11.4	89	7	31.2	18%
17	366	61.7	50.9	10.8	88	7	29.6	18%
18	530	75.3	66.8	8.5	92	2	16.0	11%

Table 4-8: Average Event-Hour Load Impacts – *PG&E CBP DO*

Hour Ending	Number of SAIDs Called	Estimated Reference Load (MW)	Observed Load (MW)	Estimated Load Impact (MW)	Weighted Average Temp (°F)	# of Events this Hour is included	Load Impact per Called Customer (kW)	% Load Impact
13	123	46.8	37.7	9.1	94	1	73.6	19%
14	171	70.3	57.3	13.0	92	5	75.7	18%
15	359	160.0	131.7	28.3	92	6	78.8	18%
16	352	154.2	126.2	28.1	93	7	79.7	18%
17	352	153.6	125.2	28.4	93	7	80.7	18%
18	321	138.4	113.3	25.1	93	6	78.2	18%
19	126	46.8	39.1	7.7	92	4	61.1	16%

Tables 4–9 and 4–10 show hourly reference load, observed load, load impact, and uncertainty-adjusted load-impact values for the average PG&E CBP ***DA*** and ***DO*** events respectively, in the Protocol table format. Hourly load impacts for the DA event were 18 percent of the reference load of about 62 MW in the event hours most often called, and were 18 percent of the reference load of 154 MW for DO. The 10^{th} and 90^{th} percentile uncertainty-adjusted load impacts are estimated to be 12 percent below and above the estimated load impacts for the most frequent event hours for DA and 4 percent for DO.

Figure 4–1 shows the hourly reference load, observed load, and estimated load impacts (see right axis) for the typical PG&E CBP DA event, while Figure 4–2 shows comparable information for the typical DO event.

Table 4-9: Hourly Load Impacts – *PG&E CBP Average DA Event*

Hour Ending	Estimated Reference Load (MWh/hr)	Observed Event-Day Load (MWh/hr)	Estimated Load Impact (MWh/hr)	Weighted Average Temperature (°F)	Uncertainty Adjusted Impact (MWh/hr) - Percentiles				
					10th%ile	30th%ile	50th%ile	70th%ile	90th%ile
1	41.2	41.3	-0.2	69	-1.6	-0.8	-0.2	0.4	1.2
2	40.5	40.5	0.1	68	-1.3	-0.5	0.1	0.6	1.5
3	40.1	39.8	0.3	67	-1.1	-0.3	0.3	0.9	1.7
4	40.1	40.0	0.1	66	-1.3	-0.5	0.1	0.7	1.5
5	40.8	40.8	0.0	65	-1.4	-0.6	0.0	0.5	1.4
6	43.1	43.3	-0.2	64	-1.6	-0.7	-0.2	0.4	1.2
7	48.1	48.7	-0.6	64	-2.0	-1.2	-0.6	-0.1	0.7
8	52.7	53.3	-0.6	65	-2.0	-1.2	-0.6	0.0	0.8
9	57.5	58.0	-0.5	69	-1.9	-1.1	-0.5	0.1	0.9
10	60.5	61.1	-0.6	72	-2.0	-1.2	-0.6	0.0	0.8
11	62.8	63.6	-0.9	76	-2.3	-1.5	-0.9	-0.3	0.5
12	63.7	64.2	-0.4	80	-1.8	-1.0	-0.4	0.1	1.0
13	63.4	64.1	-0.7	83	-2.1	-1.3	-0.7	-0.1	0.7
14	63.7	62.8	0.9	85	-0.5	0.3	0.9	1.5	2.3
15	63.5	57.2	6.2	87	4.8	5.7	6.2	6.8	7.6
16	63.5	52.0	11.4	88	10.0	10.9	11.4	12.0	12.8
17	61.8	51.0	10.8	88	9.5	10.3	10.8	11.4	12.2
18	58.0	51.4	6.6	86	5.2	6.0	6.6	7.1	8.0
19	52.7	49.3	3.4	82	2.0	2.8	3.4	4.0	4.8
20	51.1	49.2	1.8	78	0.4	1.3	1.8	2.4	3.2
21	49.4	48.4	1.0	74	-0.4	0.4	1.0	1.6	2.4
22	48.0	46.8	1.2	71	-0.1	0.7	1.2	1.8	2.6
23	46.5	45.3	1.3	69	-0.1	0.7	1.3	1.8	2.6
24	44.3	43.3	1.0	68	-0.4	0.4	1.0	1.6	2.4

	Reference Energy Use (MWh)	Observed Event-Day Energy Use (MWh)	Change in Energy Use (MWh)	Cooling Degree Hours (Base 75° F)	Uncertainty Adjusted Impact (MWh/hr) - Percentiles				
					10th	30th	50th	70th	90th
Daily	1,257	1,216	41	84.5	n/a	n/a	n/a	n/a	n/a

Table 4-10: Hourly Load Impacts – *PG&E CBP Average DO Event*

Hour Ending	Estimated Reference Load (MWh/hr)	Observed Event-Day Load (MWh/hr)	Estimated Load Impact (MWh/hr)	Weighted Average Temperature (°F)	Uncertainty Adjusted Impact (MWh/hr) - Percentiles				
					10th%ile	30th%ile	50th%ile	70th%ile	90th%ile
1	83.9	83.4	0.4	70	-0.8	-0.1	0.4	0.9	1.7
2	81.9	81.4	0.5	68	-0.8	0.0	0.5	1.0	1.7
3	80.2	79.8	0.4	67	-0.9	-0.1	0.4	0.9	1.6
4	81.0	80.3	0.7	66	-0.6	0.2	0.7	1.2	1.9
5	86.1	85.4	0.7	65	-0.5	0.2	0.7	1.2	1.9
6	92.2	92.0	0.2	64	-1.0	-0.3	0.2	0.7	1.5
7	109.4	110.0	-0.5	64	-1.7	-1.0	-0.5	0.0	0.7
8	113.4	113.9	-0.5	66	-1.8	-1.1	-0.5	0.0	0.7
9	123.2	124.7	-1.5	71	-2.8	-2.0	-1.5	-1.0	-0.3
10	130.8	132.6	-1.8	76	-3.1	-2.3	-1.8	-1.3	-0.6
11	140.2	141.5	-1.4	80	-2.6	-1.9	-1.4	-0.8	-0.1
12	145.6	146.5	-0.9	84	-2.2	-1.5	-0.9	-0.4	0.3
13	149.2	147.4	1.8	87	0.6	1.3	1.8	2.3	3.0
14	152.0	140.2	11.7	90	10.5	11.2	11.7	12.2	13.0
15	153.5	128.8	24.7	92	23.4	24.2	24.7	25.2	25.9
16	154.5	126.4	28.1	93	26.9	27.6	28.1	28.6	29.3
17	153.9	125.4	28.4	93	27.2	27.9	28.4	28.9	29.7
18	150.9	127.8	23.1	92	21.9	22.6	23.1	23.6	24.3
19	145.0	136.0	9.0	89	7.8	8.5	9.0	9.5	10.2
20	143.4	142.3	1.0	84	-0.2	0.5	1.0	1.5	2.3
21	141.1	140.9	0.2	80	-1.0	-0.3	0.2	0.7	1.5
22	128.0	128.0	0.0	77	-1.2	-0.5	0.0	0.5	1.3
23	103.6	104.0	-0.3	74	-1.6	-0.8	-0.3	0.2	0.9
24	93.2	93.9	-0.7	72	-2.0	-1.2	-0.7	-0.2	0.5

	Reference Energy Use (MWh)	Observed Event-Day Energy Use (MWh)	Change in Energy Use (MWh)	Cooling Degree Hours (Base 75° F)	Uncertainty Adjusted Impact (MWh/hr) - Percentiles				
					10th	30th	50th	70th	90th
Daily	2,936	2,813	123	140.5	n/a	n/a	n/a	n/a	n/a

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

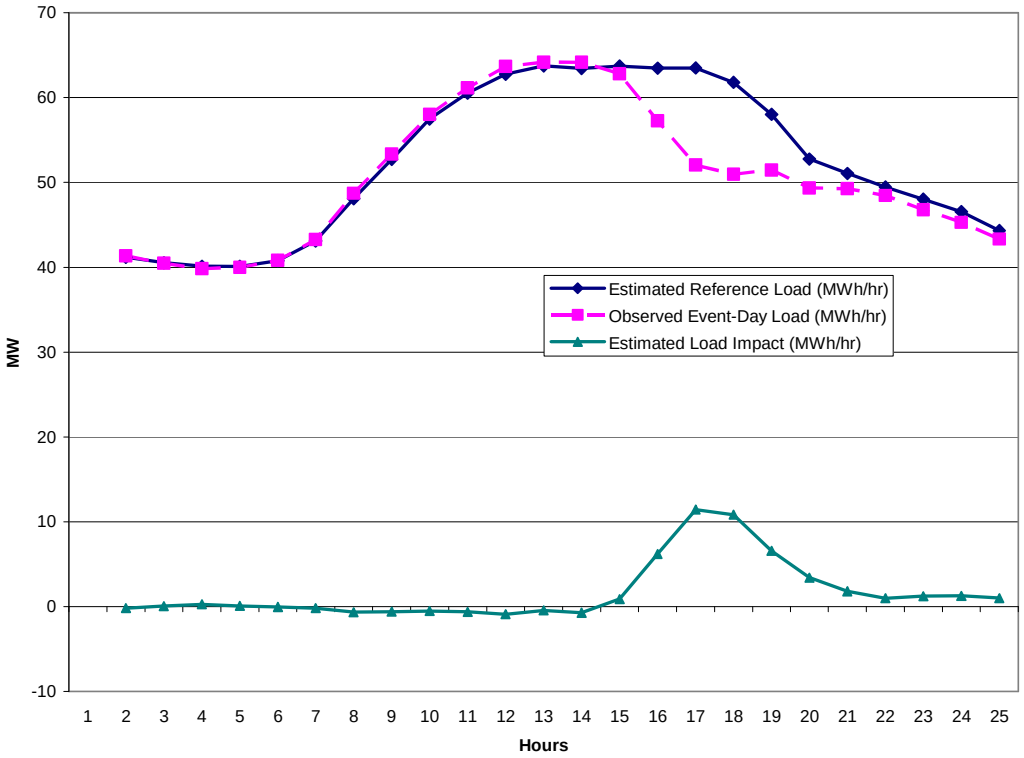
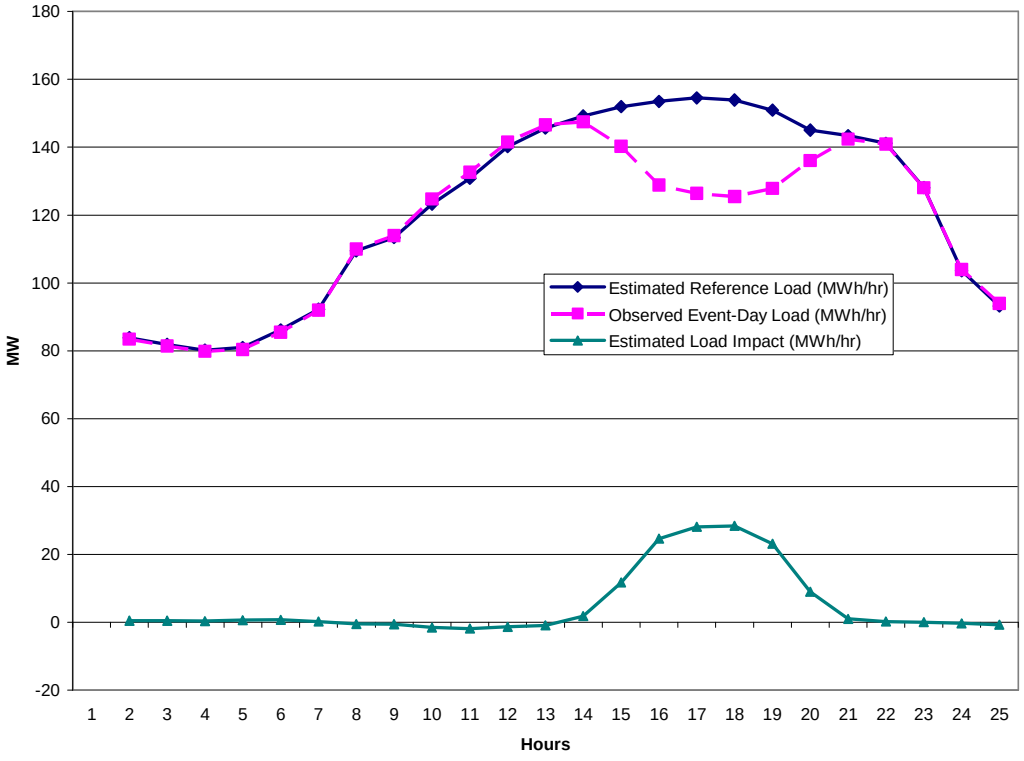


Figure 4-2: Hourly Loads and Load Impacts – *PG&E CBP DO Event*



4.2 CBP – SCE

4.2.1 Summary load impacts

Tables 4–11 and 4–12 summarize estimated *average hourly* ex post load impacts for each SCE event, for the DA and DO product types respectively, as well as for typical DA and DO events. The typical DA event was defined as the average across all events except event 11, for which only two of the three aggregators were called. The typical average hourly DA load impact was 0.85 MW, less than half of the nominated amount. The typical DO event was defined as the average across all events except events 1, 2, and 15, for which not all aggregators were called. The average hourly DO load impact for the typical event was 15.4 MW. Load impacts for most events were reasonably close to nominated amounts, exceeding those levels for several events.

Table 4-11: Average Hourly Load Impacts by Event (kW) – *SCE CBP DA*

Event	Date	Day of Week	SAIDs Called	Estimated Reference Load (MW)	Observed Load (MW)	Estimated Load Impact (MW)	% Load Impact	Nominated Load Impact (MW)
1	July 14, 2010	Wednesday		-	-	-		
2	July 15, 2010	Thursday		-	-	-		
3	July 16, 2010	Friday	78	8.9	7.8	1.1	13%	2.2
4	July 19, 2010	Monday	78	8.3	7.4	1.0	11%	2.2
5	August 16, 2010	Monday	77	7.7	7.0	0.7	9%	2.2
6	August 17, 2010	Tuesday	77	8.1	6.9	1.1	14%	2.2
7	August 23, 2010	Monday	77	8.4	7.5	0.8	10%	2.2
8	August 24, 2010	Tuesday	77	8.4	8.4	(0.0)	0%	2.2
9	August 25, 2010	Wednesday	77	8.2	7.4	0.9	10%	2.2
10	August 26, 2010	Thursday	77	8.0	7.1	0.9	12%	2.2
11	August 27, 2010	Friday	75	5.3	4.5	0.8	16%	2.2
12	September 1, 2010	Wednesday	78	7.9	7.0	0.9	12%	2.2
13	September 2, 2010	Thursday	78	8.1	7.0	1.1	14%	2.2
14	September 3, 2010	Friday	78	7.4	6.7	0.7	10%	2.2
15	September 24, 2010	Friday		-	-	-		
16	September 27, 2010	Monday	78	9.5	8.3	1.3	13%	2.2
17	September 28, 2010	Tuesday	78	8.8	8.2	0.6	7%	2.2
18	September 29, 2010	Wednesday	78	8.4	7.8	0.6	8%	2.2
19	September 30, 2010	Thursday	78	8.4	7.5	0.9	11%	2.2
	Average		78	8.3	7.5	0.8	10%	
	Standard Deviation			0.5	0.5	0.3	4%	

Table 4-12: Average Hourly Load Impacts by Event (kW) – *SCE CBP DO*

Event	Date	Day of Week	SAIDs Called	Estimated Reference Load (MW)	Observed Load (MW)	Estimated Load Impact (MW)	% Load Impact	Nominated Load Impact (MW)
1	July 14, 2010	Wednesday	305	76.7	68.0	8.7	11%	14.7
2	July 15, 2010	Thursday	305	77.4	65.0	12.5	16%	14.7
3	July 16, 2010	Friday	305	79.6	65.0	14.5	18%	14.7
4	July 19, 2010	Monday		-	-	-		
5	August 16, 2010	Monday		-	-	-		
6	August 17, 2010	Tuesday		-	-	-		
7	August 23, 2010	Monday		-	-	-		
8	August 24, 2010	Tuesday	334	79.9	62.6	17.3	22%	16.6
9	August 25, 2010	Wednesday	334	81.2	76.7	4.5	5%	16.6
10	August 26, 2010	Thursday	334	79.8	61.5	18.4	23%	16.6
11	August 27, 2010	Friday		-	-	-		
12	September 1, 2010	Wednesday		-	-	-		
13	September 2, 2010	Thursday		-	-	-		
14	September 3, 2010	Friday		-	-	-		
15	September 24, 2010	Friday	197	29.7	25.4	4.3	15%	5.0
16	September 27, 2010	Monday	359	99.3	80.1	19.2	19%	17.3
17	September 28, 2010	Tuesday	359	94.3	76.0	18.3	19%	17.3
18	September 29, 2010	Wednesday		-	-	-		
19	September 30, 2010	Thursday		-	-	-		
	Average		338	85.7	70.3	15.4	18%	
	Standard Deviation			8.8	8.2	5.6	6%	

Tables 4–13 and 4–14 show average hourly estimated *reference load*, *observed load*, *load impacts* and percent load impact, by industry group, for the typical event for the DA and DO product types respectively. Retail stores provided most all of the DA and DO load impacts.[14] The average percent load reductions across all industry types was 10 percent for DA and 18 percent for DO.

Table 4-13: Average Hourly Load Impacts by Industry Type – *SCE CBP DA*

Industry Group	SAIDs Called	Estimated Reference Load (MW)	Observed Load (MW)	Estimated Load Impact (MW)	%LI
1. Agriculture, Mining & Construction					
2. Manufacturing	1	1.0	1.0	0.0	1%
3. Wholesale, Transport, other Utilities					
4. Retail stores	74	5.7	4.8	0.9	15%
5. Offices, Hotels, Health, Services	3	1.6	1.6	(0.0)	-1%
6. Schools					
7. Entertainment, Other Services, Gov't					
8. Other/Unknown					
Total	78	8.3	7.5	0.8	10%

[14] Note that the negative load impacts for industry groups 3 and 6 indicate that the regression analysis implied that those few customers *increased* usage during event hours on average. This occurs occasionally for some customers on the aggregator programs. However, it is unusual.

Table 4-14: Average Hourly Load Impacts by Industry Type – *SCE CBP DO*

Industry Group	SAIDs Called	Estimated Reference Load (MW)	Observed Load (MW)	Estimated Load Impact (MW)	%LI
1. Agriculture, Mining & Construction	2	0.4	0.2	0.2	45%
2. Manufacturing	1	0.1	0.1	0.0	22%
3. Wholesale, Transport, other Utilities	2	0.7	0.7	(0.1)	-9%
4. Retail stores	299	75.1	59.6	15.5	21%
5. Offices, Hotels, Health, Services	34	5.3	4.8	0.5	9%
6. Schools	1	4.1	4.9	(0.8)	-19%
7. Entertainment, Other Services, Gov't					
8. Other/Unknown					
Total	338	85.7	70.3	15.4	18%

Tables 4–15 and 4–16 show average hourly load impacts by LCA. Most of the DA and DO load impacts occurred in the LA Basin.

Table 4-15: Average Hourly Load Impacts by LCA – *SCE CBP DA*

LCA	SAIDs Called	Estimated Reference Load (MW)	Observed Load (MW)	Estimated Load Impact (MW)	%LI
1. LA Basin	61	6.0	5.4	0.6	10%
2. Outside LA Basin	5	0.5	0.4	0.1	16%
3. Ventura	12	1.9	1.7	0.1	8%
Total	78	8.3	7.5	0.8	10%

Table 4-16: Average Hourly Load Impacts by LCA – *SCE CBP DO*

LCA	SAIDs Called	Estimated Reference Load (MW)	Observed Load (MW)	Estimated Load Impact (MW)	%LI
1. LA Basin	272	68.7	57.0	11.6	17%
2. Outside LA Basin	21	6.1	4.7	1.4	23%
3. Ventura	45	10.9	8.6	2.3	21%
Total	338	85.7	70.3	15.4	18%

4.2.2 Hourly load impacts

Tables 4–17 and 4–18 show average event-hour load impacts for typical SCE CBP DA and DO product types respectively. Average event-hour load impacts for DA for HE 15 – 17 ranged from 0.8 to 1 MW, which represented 9 to 12 percent of the reference load. Load impacts per called customer were relatively small, ranging from 10 to 14 kW, with the exception of the two customers that were called in HE 13.

For DO, average event-hour load impacts ranged from 12 to 16 MW, representing 16 to 22 percent of the reference load, across all hours shown. Average event-hour load impacts per called customer ranged from 41 to 87 kW.

Table 4-17: Average Event-Hour Load Impacts – *SCE CBP DA*

Hour Ending	Number of SAIDs Called	Estimated Reference Load (MW)	Observed Load (MW)	Estimated Load Impact (MW)	Weighted Average Temp (°F)	# of Events this Hour is included	Load Impact per Called Customer (kW)	% Load Impact
13	2	1.5	1.3	0.1	80	2	74.6	10%
14	52	6.2	5.8	0.4	86	3	7.3	6%
15	77	8.5	7.4	1.0	88	7	13.5	12%
16	77	8.1	7.2	0.8	84	16	10.7	10%
17	77	8.2	7.4	0.8	83	16	9.8	9%
18	47	5.9	5.3	0.7	85	5	14.1	11%

Table 4-18: Average Event-Hour Load Impacts – *SCE CBP DO*

Hour Ending	Number of SAIDs Called	Estimated Reference Load (MW)	Observed Load (MW)	Estimated Load Impact (MW)	Weighted Average Temp (°F)	# of Events this Hour is included	Load Impact per Called Customer (kW)	% Load Impact
13	162	65.1	51.1	14.0	102	1	86.6	22%
14	297	80.6	66.7	13.9	95	4	46.8	17%
15	314	82.3	67.5	14.8	94	7	47.1	18%
16	329	83.1	69.5	13.6	93	8	41.4	16%
17	329	83.6	69.0	14.6	92	8	44.4	17%
18	278	77.0	61.0	15.9	90	6	57.5	21%
19	210	57.3	45.3	12.0	84	5	57.2	21%

Tables 4–19 and 4–20 show hourly reference load, observed load, load impact, and uncertainty-adjusted load-impact values for the typical SCE CBP ***DA*** and ***DO*** events respectively. Hourly load impacts of the DA product type averaged 9 to 10 percent of the reference load of 8 MW in hours 16 and 17. Hourly load impacts of the DO product type and averaged 15 to 17 percent of the reference load of about 78 MW. The 10^{th} and 90^{th} percentile uncertainty-adjusted load impacts are estimated to be relatively large for DA, at 35 to 38 percent, and are 12 to 14 percent below and above the estimated load impacts for the typical DO event.

Table 4-19: Hourly Load Impacts – *SCE Average CBP DA Event*

Hour Ending	Estimated Reference Load (MWh/hr)	Observed Event-Day Load (MWh/hr)	Estimated Load Impact (MWh/hr)	Weighted Average Temperature (°F)	Uncertainty Adjusted Impact (MWh/hr) - Percentiles				
					10th%ile	30th%ile	50th%ile	70th%ile	90th%ile
1	2.7	2.9	-0.1	68	-0.4	-0.2	-0.1	0.0	0.2
2	2.8	2.8	-0.1	67	-0.4	-0.2	-0.1	0.0	0.2
3	2.7	2.8	-0.1	66	-0.4	-0.2	-0.1	0.0	0.2
4	2.8	2.8	0.0	66	-0.3	-0.2	0.0	0.1	0.3
5	2.9	2.9	0.0	65	-0.3	-0.1	0.0	0.1	0.3
6	3.0	3.0	0.0	65	-0.3	-0.1	0.0	0.1	0.3
7	3.8	3.9	-0.1	65	-0.4	-0.2	-0.1	0.0	0.2
8	5.3	5.5	-0.2	67	-0.5	-0.4	-0.2	-0.1	0.1
9	6.9	7.0	0.0	71	-0.3	-0.1	0.0	0.1	0.3
10	7.0	7.1	-0.1	75	-0.4	-0.2	-0.1	0.0	0.2
11	7.2	7.4	-0.2	79	-0.5	-0.4	-0.2	-0.1	0.0
12	7.6	7.7	-0.1	81	-0.4	-0.3	-0.1	0.0	0.2
13	7.8	7.9	0.0	83	-0.3	-0.2	0.0	0.1	0.2
14	8.0	7.9	0.1	84	-0.2	0.0	0.1	0.2	0.4
15	8.1	7.6	0.4	84	0.1	0.3	0.4	0.6	0.7
16	8.1	7.2	0.8	84	0.5	0.7	0.8	0.9	1.1
17	8.2	7.4	0.8	83	0.5	0.6	0.8	0.9	1.1
18	8.2	8.4	-0.2	81	-0.5	-0.3	-0.2	-0.1	0.1
19	8.0	8.3	-0.3	78	-0.6	-0.4	-0.3	-0.2	0.0
20	7.4	7.6	-0.1	74	-0.4	-0.3	-0.1	0.0	0.1
21	6.0	6.1	-0.1	72	-0.4	-0.2	-0.1	0.0	0.2
22	4.3	4.5	-0.2	70	-0.5	-0.3	-0.2	0.0	0.1
23	3.6	3.6	0.0	69	-0.3	-0.1	0.0	0.1	0.3
24	3.2	3.1	0.1	68	-0.2	0.0	0.1	0.2	0.4

	Reference Energy Use (MWh)	Observed Event-Day Energy Use (MWh)	Change in Energy Use (MWh)	Cooling Degree Hours (Base 75° F)	Uncertainty Adjusted Impact (MWh/hr) - Percentiles				
					10th	30th	50th	70th	90th
Daily	135	135	0	62.2	n/a	n/a	n/a	n/a	n/a

Table 4-20: Hourly Load Impacts – *SCE Average CBP DO Event*

Hour Ending	Estimated Reference Load (MWh/hr)	Observed Event-Day Load (MWh/hr)	Estimated Load Impact (MWh/hr)	Weighted Average Temperature (°F)	Uncertainty Adjusted Impact (MWh/hr) - Percentiles				
					10th%ile	30th%ile	50th%ile	70th%ile	90th%ile
1	34.0	34.7	-0.6	74	-2.2	-1.3	-0.6	0.0	0.9
2	32.1	34.2	-2.1	73	-3.7	-2.7	-2.1	-1.5	-0.5
3	31.9	33.9	-2.0	72	-3.6	-2.7	-2.0	-1.4	-0.4
4	32.7	34.4	-1.7	72	-3.3	-2.4	-1.7	-1.1	-0.2
5	38.6	40.3	-1.8	71	-3.4	-2.4	-1.8	-1.1	-0.2
6	43.3	44.5	-1.3	71	-2.8	-1.9	-1.3	-0.6	0.3
7	58.7	58.1	0.6	71	-0.9	0.0	0.6	1.3	2.2
8	58.9	57.9	1.0	73	-0.6	0.4	1.0	1.6	2.6
9	61.6	62.3	-0.7	77	-2.3	-1.3	-0.7	0.0	0.9
10	66.8	67.7	-0.9	82	-2.5	-1.6	-0.9	-0.3	0.6
11	72.9	73.4	-0.5	86	-2.0	-1.1	-0.5	0.2	1.1
12	75.5	75.9	-0.4	90	-2.0	-1.1	-0.4	0.2	1.2
13	76.1	74.2	1.8	92	0.3	1.2	1.8	2.5	3.4
14	77.1	69.7	7.4	93	5.8	6.8	7.4	8.1	9.0
15	77.4	66.0	11.4	94	9.8	10.8	11.4	12.1	13.0
16	77.0	64.8	12.2	93	10.6	11.5	12.2	12.8	13.8
17	77.7	64.7	13.0	92	11.4	12.4	13.0	13.7	14.6
18	77.9	66.7	11.2	90	9.6	10.5	11.2	11.8	12.7
19	77.1	69.6	7.6	87	6.0	6.9	7.6	8.2	9.1
20	77.7	77.9	-0.2	84	-1.8	-0.8	-0.2	0.5	1.4
21	77.1	77.4	-0.3	81	-1.8	-0.9	-0.3	0.4	1.3
22	66.4	68.2	-1.8	78	-3.4	-2.4	-1.8	-1.1	-0.2
23	46.3	48.1	-1.8	77	-3.3	-2.4	-1.8	-1.1	-0.2
24	37.4	39.1	-1.6	75	-3.2	-2.3	-1.6	-1.0	-0.1

	Reference Energy Use (MWh)	Observed Event-Day Energy Use (MWh)	Change in Energy Use (MWh)	Cooling Degree Hours (Base 75° F)	Uncertainty Adjusted Impact (MWh/hr) - Percentiles				
					10th	30th	50th	70th	90th
Daily	1,452	1,404	49	172.5	n/a	n/a	n/a	n/a	n/a

Figure 4–3 shows the profiles of the hourly reference load, observed load, and estimated load impacts (see right axis) for the average SCE CBP DA event. Figure 4–4 shows comparable information for the average DO event.

Figure 4-3: Hourly Loads and Load Impacts – *SCE CBP DA Average Event*

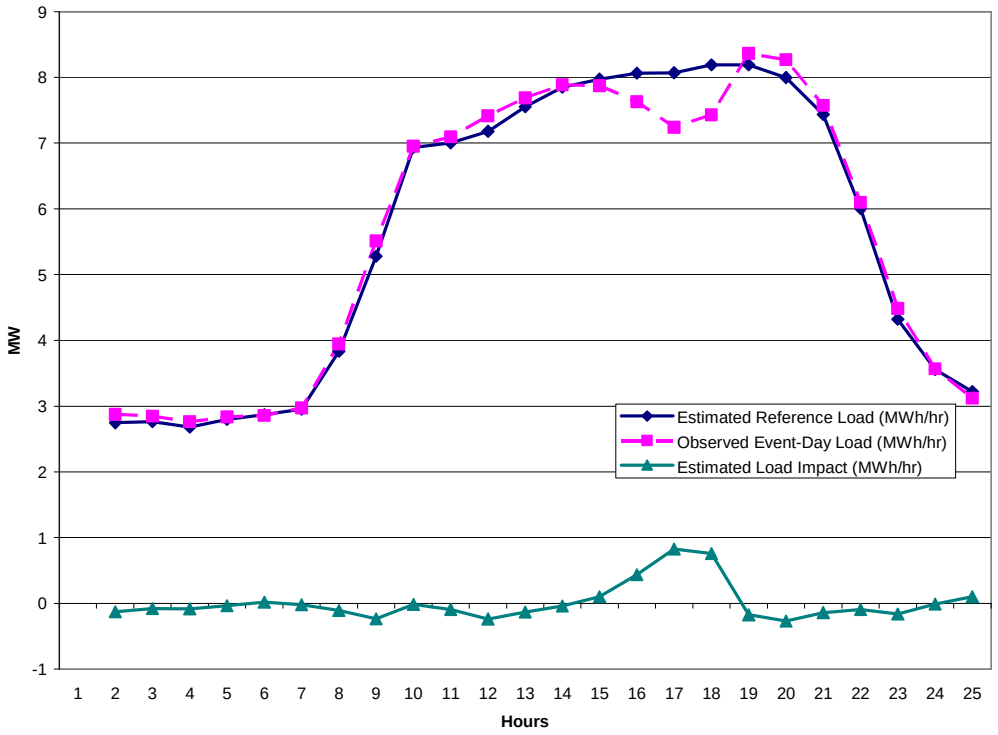
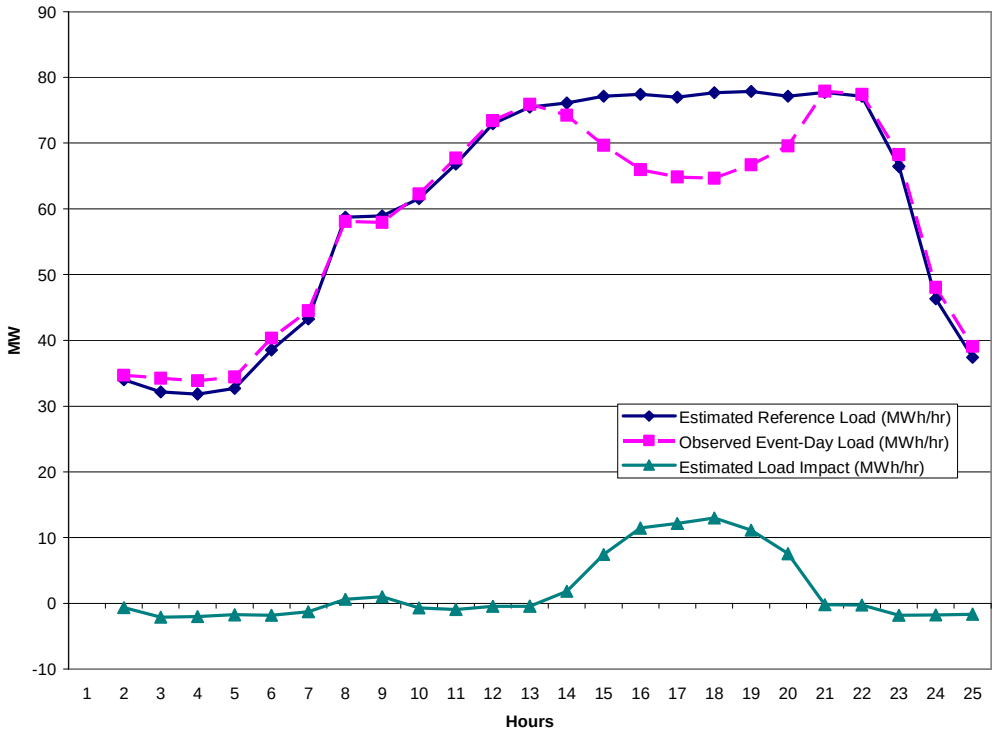


Figure 4-4: Hourly Loads and Load Impacts – *SCE CBP DO Average Event*



4.3 CBP – SDG&E

4.3.1 Summary load impacts

Tables 4–21 and 4–22 summarize estimated average hourly reference loads and *ex post* load impacts for each event, and for the typical event, for SDG&E's DA and DO product types respectively. The average DA event was calculated across all but the sixth event, for which one aggregator was not notified due to a communication failure. Average hourly load impacts were quite consistent across events for both DA and DO product types, with an average hourly load impact of 9.6 MW for the average DA event, and 8.7 for the average DO event. Those represent 29 percent of the reference load for DA, and 16 percent for DO. DA load impacts typically met or exceeded the nominated amounts. DO load impacts fell short of nominated levels in July and August, but were close in September once nominations were lowered.

Table 4-21: Average Hourly Load Impacts (kW) by Event – *SDG&E CBP DA*

Event	Date	Day of Week	SAIDs Called	Estimated Reference Load (MW)	Observed Load (MW)	Estimated Load Impact (MW)	% Load Impact	Nominated Load Impact (MW)
1	July 14, 2010	Wednesday		-	-	-		
2	July 15, 2010	Thursday		-	-	-		
3	July 16, 2010	Friday	121	34.2	24.4	9.8	29%	10.7
4	August 18, 2010	Wednesday		-	-	-		
5	August 19, 2010	Thursday	116	34.7	26.0	8.7	25%	9.0
6	August 20, 2010	Friday	71	16.1	14.7	1.5	9%	2.1
7	August 23, 2010	Monday		-	-	-		
8	August 24, 2010	Tuesday	116	35.2	25.4	9.8	28%	9.0
9	August 25, 2010	Wednesday	116	34.5	25.8	8.6	25%	9.0
10	August 26, 2010	Thursday	116	34.2	24.0	10.2	30%	9.0
11	September 27, 2010	Monday		-	-	-		
12	September 28, 2010	Tuesday	83	30.4	19.7	10.7	35%	10.4
13	September 29, 2010	Wednesday		-	-	-		
	Average		111	33.9	24.2	9.6	29%	
	Standard Deviation			1.7	2.4	0.8	4%	

Table 4-22: Average Hourly Load Impacts (kW) by Event – *SDG&E CBP DO*

Event	Date	Day of Week	SAIDs Called	Estimated Reference Load (MW)	Observed Load (MW)	Estimated Load Impact (MW)	% Load Impact	Nominated Load Impact (MW)
1	July 14, 2010	Wednesday	279	58.2	49.8	8.4	14%	20.5
2	July 15, 2010	Thursday	279	59.4	50.5	8.9	15%	20.5
3	July 16, 2010	Friday	279	61.3	51.5	9.8	16%	20.5
4	August 18, 2010	Wednesday	274	57.7	49.1	8.6	15%	14.1
5	August 19, 2010	Thursday	274	56.9	49.0	8.0	14%	14.1
6	August 20, 2010	Friday		-	-	-		
7	August 23, 2010	Monday	274	56.5	47.3	9.2	16%	14.1
8	August 24, 2010	Tuesday	274	57.3	47.8	9.5	17%	14.1
9	August 25, 2010	Wednesday	274	57.4	48.4	9.0	16%	14.1
10	August 26, 2010	Thursday	274	56.1	48.0	8.2	15%	14.1
11	September 27, 2010	Monday	250	48.8	40.8	8.0	16%	10.2
12	September 28, 2010	Tuesday	250	47.9	37.8	10.1	21%	10.2
13	September 29, 2010	Wednesday	250	47.0	40.4	6.7	14%	10.2
	Average		269	55.4	46.7	8.7	16%	
	Standard Deviation			4.7	4.5	0.9	2%	

Tables 4–23 and 4–24 show average hourly program load impacts and percent load impacts by industry type, for the typical DA and DO event respectively. The Manufacturing industry group provided the largest share of DA load impacts, while Retail stores provided the largest share of DO load impacts.

Table 4-23: Average Hourly Load Impacts by Industry Type – *SDG&E CBP DA*

Industry Group	SAIDs Called	Estimated Reference Load (MW)	Observed Load (MW)	Estimated Load Impact (MW)	% Load Impact
1. Agriculture, Mining & Construction	2	0.8	0.6	0.2	26%
2. Manufacturing	20	11.8	4.4	7.4	63%
3. Wholesale, Transport, other Utilities	10	4.0	3.1	0.9	23%
4. Retail stores					
5. Offices, Hotels, Health, Services	76	16.3	15.6	0.7	4%
6. Schools					
7. Entertainment, Other Services, Gov't	4	0.9	0.5	0.4	42%
8. Other/Unknown					
Total	111	33.9	24.2	9.6	28%

Table 4-24: Average Hourly Load Impacts by Industry Type – *SDG&E CBP DO*

Industry Group	SAIDs Called	Estimated Reference Load (MW)	Observed Load (MW)	Estimated Load Impact (MW)	% Load Impact
1. Agriculture, Mining & Construction					
2. Manufacturing	5	1.7	1.6	0.1	6%
3. Wholesale, Transport, other Utilities	21	3.7	2.8	0.9	24%
4. Retail stores	170	37.2	31.8	5.5	15%
5. Offices, Hotels, Health, Services	32	6.2	5.3	0.9	15%
6. Schools					
7. Entertainment, Other Services, Gov't	41	6.5	5.2	1.3	20%
8. Other/Unknown	1	0.1	0.0	0.0	29%
Total	269	55.4	46.7	8.7	16%

4.3.2 Hourly load impacts

Tables 4–25 and 4–26 show average event-hour load impacts for SDG&E's typical CBP DA and DO product types. Average event-hour load impacts for DA ranged from 7 to 9.5 MW across all event hours called. Percentage load impacts ranged from 24 to 34 percent, and load impacts per customer ranged from 68 to 114 kW.

For DO, average event-hour load impacts were consistent at 8.3 to 8.7 MW for the hours called most often, representing 15 to 16 percent of the reference load. Average event-hour load impact per called customer was 32 kW.

Table 4-25: Average Event-Hour Load Impacts – *SDG&E CBP DA*

Hour Ending	Number of SAIDs Called	Estimated Reference Load (MW)	Observed Load (MW)	Estimated Load Impact (MW)	Weighted Average Temp (°F)	# of Events this Hour is included	Load Impact per Called Customer (kW)	% Load Impact
14	109	31.2	23.8	7.4	80	6	67.7	24%
15	106	31.4	22.8	8.6	79	7	81.2	27%
16	106	32.1	23.2	8.9	78	7	84.3	28%
17	106	31.1	22.4	8.7	77	7	82.8	28%
18	83	27.8	18.3	9.5	78	1	114.3	34%

Table 4-26: Average Event-Hour Load Impacts – *SDG&E CBP DO*

Hour Ending	Number of SAIDs Called	Estimated Reference Load (MW)	Observed Load (MW)	Estimated Load Impact (MW)	Weighted Average Temp (°F)	# of Events this Hour is included	Load Impact per Called Customer (kW)	% Load Impact
14	247	53.6	45.3	8.4	84	11	33.8	16%
15	258	54.3	46.0	8.4	84	12	32.3	15%
16	258	54.5	46.2	8.3	83	12	32.0	15%
17	269	55.3	46.6	8.7	81	12	32.2	16%
18	250	48.0	40.0	8.0	83	3	32.2	17%
19	119	34.4	29.9	4.6	80	2	38.5	13%

Tables 4–27 and 4–28 show hourly reference load, observed load, load impact, and uncertainty-adjusted load-impact values for the average SDG&E CBP ***DA*** and ***DO*** program events respectively. Hourly load impacts were 27 to 28 percent of the reference load of about 31 MW for the average DA event, and 15 percent of the reference load of 55 MW for DO. The 10^{th} and 90^{th} percentile uncertainty-adjusted load impacts are estimated to be about 21 percent below and above the estimated load impacts for the average DA event and 7 percent for the average DO event.

Table 4-27: Hourly Load Impacts – *SDG&E Average CBP DA Event*

Hour Ending	Estimated Reference Load (MWh/hr)	Observed Event-Day Load (MWh/hr)	Estimated Load Impact (MWh/hr)	Weighted Average Temperature (°F)	Uncertainty Adjusted Impact (MWh/hr) - Percentiles				
					10th%ile	30th%ile	50th%ile	70th%ile	90th%ile
1	17.0	16.5	0.5	71	-1.4	-0.3	0.5	1.3	2.4
2	16.6	16.1	0.6	70	-1.3	-0.2	0.6	1.3	2.4
3	16.2	15.8	0.4	70	-1.5	-0.4	0.4	1.2	2.3
4	16.2	15.8	0.3	69	-1.6	-0.4	0.3	1.1	2.2
5	17.3	17.2	0.1	69	-1.8	-0.7	0.1	0.8	1.9
6	20.0	20.5	-0.5	69	-2.4	-1.3	-0.5	0.2	1.3
7	23.7	24.3	-0.6	69	-2.4	-1.3	-0.6	0.2	1.3
8	26.0	26.1	-0.1	71	-2.0	-0.9	-0.1	0.7	1.8
9	28.0	30.4	-2.4	75	-4.2	-3.1	-2.4	-1.6	-0.5
10	30.6	30.9	-0.3	77	-2.2	-1.1	-0.3	0.5	1.6
11	31.7	32.6	-0.9	78	-2.8	-1.7	-0.9	-0.2	0.9
12	32.0	30.6	1.4	79	-0.5	0.7	1.4	2.2	3.3
13	31.8	27.6	4.2	79	2.4	3.5	4.2	5.0	6.1
14	31.2	23.8	7.4	80	5.5	6.6	7.4	8.1	9.2
15	31.4	22.8	8.6	80	6.7	7.8	8.6	9.3	10.4
16	32.1	23.2	8.9	78	7.0	8.1	8.9	9.7	10.8
17	31.1	22.4	8.7	77	6.9	8.0	8.7	9.5	10.6
18	28.8	24.1	4.7	75	2.8	3.9	4.7	5.5	6.6
19	23.0	23.6	-0.5	74	-2.4	-1.3	-0.5	0.3	1.4
20	21.0	21.6	-0.6	72	-2.5	-1.4	-0.6	0.2	1.3
21	20.7	20.9	-0.2	71	-2.1	-1.0	-0.2	0.6	1.6
22	19.8	19.4	0.4	70	-1.5	-0.4	0.4	1.1	2.2
23	18.8	18.1	0.8	69	-1.1	0.0	0.8	1.5	2.6
24	17.8	17.0	0.8	69	-1.0	0.1	0.8	1.6	2.7

	Reference Energy Use (MWh)	Observed Event-Day Energy Use (MWh)	Change in Energy Use (MWh)	Cooling Degree Hours (Base 75° F)	Uncertainty Adjusted Impact (MWh/hr) - Percentiles				
					10th	30th	50th	70th	90th
Daily	583	541	42	27.8	n/a	n/a	n/a	n/a	n/a

Table 4-28: Hourly Load Impacts – *SDG&E Average CBP DO Event*

Hour Ending	Estimated Reference Load (MWh/hr)	Observed Event-Day Load (MWh/hr)	Estimated Load Impact (MWh/hr)	Weighted Average Temperature (°F)	Uncertainty Adjusted Impact (MWh/hr) - Percentiles				
					10th%ile	30th%ile	50th%ile	70th%ile	90th%ile
1	35.6	35.5	0.1	69	-0.5	-0.1	0.1	0.3	0.6
2	34.7	34.6	0.0	69	-0.5	-0.2	0.0	0.3	0.6
3	34.3	34.4	-0.1	68	-0.6	-0.3	-0.1	0.1	0.4
4	34.4	34.5	-0.1	68	-0.6	-0.3	-0.1	0.1	0.5
5	36.2	36.4	-0.2	68	-0.7	-0.4	-0.2	0.1	0.4
6	38.9	39.0	-0.1	68	-0.7	-0.4	-0.1	0.1	0.4
7	44.3	43.3	1.0	69	0.5	0.8	1.0	1.2	1.6
8	45.1	44.3	0.8	73	0.2	0.6	0.8	1.0	1.4
9	47.3	48.0	-0.6	77	-1.2	-0.9	-0.6	-0.4	-0.1
10	49.9	51.6	-1.7	80	-2.2	-1.9	-1.7	-1.4	-1.1
11	52.1	53.4	-1.3	83	-1.9	-1.6	-1.3	-1.1	-0.8
12	53.3	54.0	-0.7	83	-1.3	-0.9	-0.7	-0.5	-0.1
13	54.6	53.7	0.9	84	0.4	0.7	0.9	1.1	1.5
14	55.1	47.1	8.0	84	7.4	7.7	8.0	8.2	8.5
15	55.3	47.0	8.4	83	7.8	8.1	8.4	8.6	8.9
16	55.5	47.1	8.4	83	7.8	8.1	8.4	8.6	8.9
17	55.3	46.6	8.7	81	8.1	8.4	8.7	8.9	9.2
18	54.8	52.1	2.7	79	2.1	2.4	2.7	2.9	3.2
19	54.0	52.9	1.0	76	0.5	0.8	1.0	1.3	1.6
20	53.6	53.5	0.1	74	-0.4	-0.1	0.1	0.3	0.7
21	51.7	52.5	-0.7	72	-1.3	-1.0	-0.7	-0.5	-0.2
22	47.9	48.6	-0.7	71	-1.2	-0.9	-0.7	-0.5	-0.1
23	41.5	41.6	-0.1	70	-0.6	-0.3	-0.1	0.2	0.5
24	37.7	37.7	0.0	70	-0.5	-0.2	0.0	0.3	0.6

	Reference Energy Use (MWh)	Observed Event-Day Energy Use (MWh)	Change in Energy Use (MWh)	Cooling Degree Hours (Base 75° F)	Uncertainty Adjusted Impact (MWh/hr) - Percentiles				
					10th	30th	50th	70th	90th
Daily	1,123	1,089	34	68.4	n/a	n/a	n/a	n/a	n/a

Figure 4–5 shows the hourly reference load, observed load, and estimated load impacts (see right axis) for the average SDG&E CBP DA event, while Figure 4–6 shows comparable results for the average DO event.

Figure 4-5: Hourly Loads and Load Impacts – *SDG&E Average CBP DA Event*

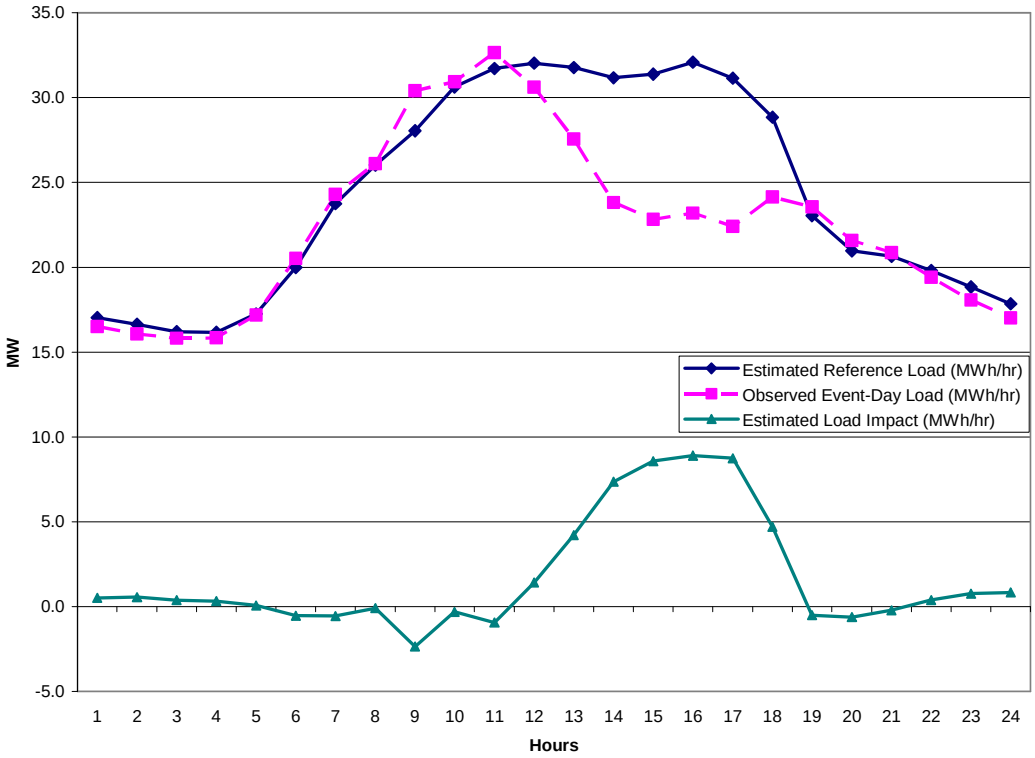
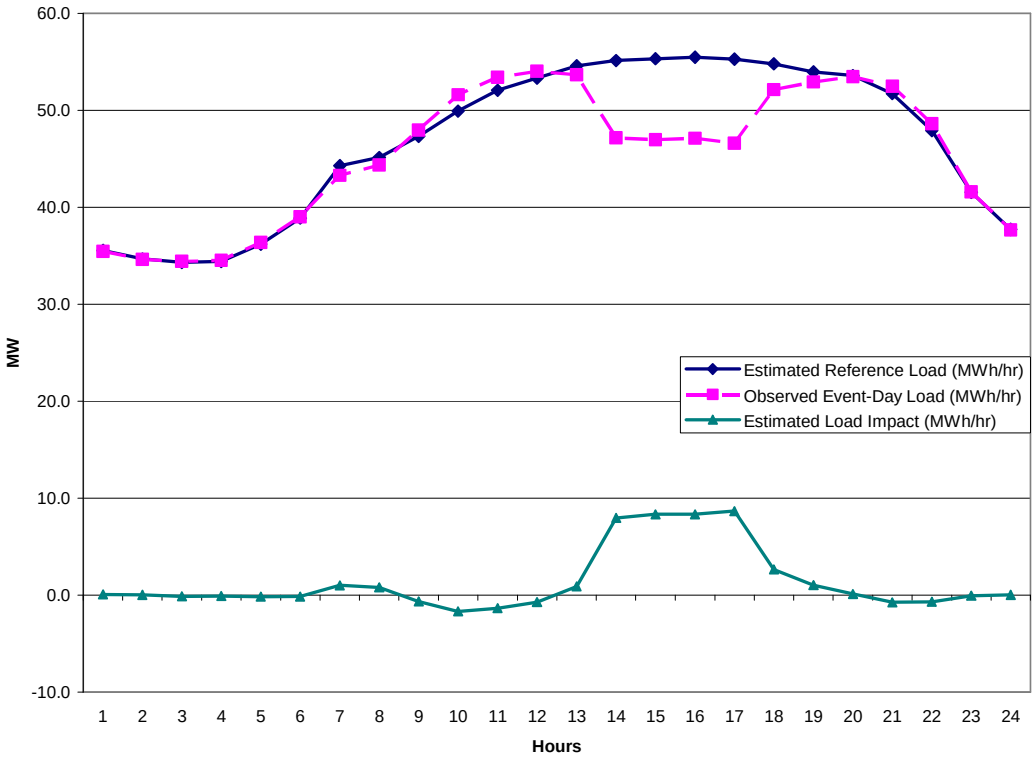


Figure 4-6: Hourly Loads and Load Impacts – *SDG&E Average CBP DO Event*



4.4 AMP – PG&E

4.4.1 Summary load impacts

Tables 4–29 and 4–30 report estimated average hourly load impacts for the DA and DO product types respectively, for the AMP test and re-test events. The first event, in which all aggregators were called, was treated as the typical event. Average hourly load impacts the average DO event they were 104.9 MW (34 percent). DO load impacts fell somewhat short of the contract amount for the July test event.

Table 4-29: Average Hourly Load Impacts by Event – *PG&E AMP DA*

Table removed for confidentiality reasons.

Table 4-30: Average Hourly Load Impacts by Event – *PG&E AMP DO*

Event	Date	Day of Week	SAIDs Called	Estimated Reference Load (MW)	Observed Load (MW)	Estimated Load Impact (MW)	% Load Impact	Contract Load Impact (MW)
1	July 16, 2010	Friday	501	306.7	201.8	104.9	34%	123.2
2	August 25, 2010	Wednesday	180	154.0	98.1	55.9	36%	51.2
Typical			501	306.7	201.8	104.9	34%	
Standard Deviation				n/a	n/a	n/a	n/a	

Tables 4–31 and 4–32 show counts of customer accounts called, and average hourly reference and observed loads, and load impacts and percentage load impacts by industry type for the typical AMP DA and DO events. Manufacturing; Wholesale, Transportation and Other Utilities; and Agriculture, Mining and Construction comprised the majority of DO load impacts.

Table 4-31: Average Hourly Load Impacts by Industry Group – *PG&E AMP DA*

Table removed for confidentiality reasons.

Table 4-32: Average Hourly Load Impacts by Industry Group – *PG&E AMP DO*

Industry Group	SAIDs Called	Estimated Reference Load (MW)	Observed Load (MW)	Estimated Load Impact (MW)	% Load Impact
1. Agriculture, Mining & Construction	129	74.6	36.3	38.2	51%
2. Manufacturing	85	64.6	42.1	22.4	35%
3. Wholesale, Transport, other Utilities	82	51.9	30.5	21.5	41%
4. Retail stores	82	33.0	27.0	6.1	18%
5. Offices, Hotels, Health, Services	107	61.0	49.2	11.8	19%
6. Schools	7	16.7	14.9	1.8	11%
7. Entertainment, Other Services, Gov't	7	4.8	1.8	3.0	62%
8. Other/Unknown	2	0.1	0.0	0.1	76%
Total	501	306.7	201.8	104.9	34%

Tables 4–33 and 4–34 report average hourly load impacts by LCA. DO load impacts were spread widely and substantial portions also occurred outside of any LCA.

Table 4-33: Average Hourly Load Impacts by LCA – *PG&E AMP DA*

Table removed for confidentiality reasons.

Table 4-34: Average Hourly Load Impacts by LCA – *PG&E AMP DO*

LCA	SAIDs Called	Estimated Reference Load (MW)	Observed Load (MW)	Estimated Load Impact (MW)	% Load Impact
1. Greater Bay Area	163	90.1	75.9	14.2	16%
2. Greater Fresno	118	49.9	27.5	22.4	45%
3. Humboldt	8	1.5	0.2	1.3	88%
4. Kern	40	36.0	18.8	17.2	48%
5. Northern Coast	34	9.5	5.6	3.9	41%
6. Sierra	12	6.0	4.7	1.4	23%
7. Stockton	19	10.3	6.5	3.8	37%
8. Not in any LCA	107	103.4	62.7	40.7	39%
Total	501	306.7	201.8	104.9	34%

4.4.2 Hourly load impacts

Tables 4–35 and 4–36 show average event-hour load impacts for PG&E's AMP DA and DO product types respectively.

For DO, average event-hour load impacts were 104 to 106 MW, representing about 35 percent of the reference load. Average event-hour load impacts per called customer were about 210 kW.

Table 4-35: Average Event-Hour Load Impacts – *PG&E AMP DA*

Table removed for confidentiality reasons.

Table 4-36: Average Event-Hour Load Impacts – *PG&E AMP DO*

Hour Ending	Number of SAIDs Called	Estimated Reference Load (MW)	Observed Load (MW)	Estimated Load Impact (MW)	Weighted Average Temp (^{o}F)	# of Events this Hour is included	Load Impact per Called Customer (kW)	% Load Impact
16	501	308.5	204.5	103.9	92	1	207.5	34%
17	501	305.0	199.1	105.8	92	1	211.2	35%

Tables 4–37 and 4–38 show hourly reference load, observed load, load impact values, and uncertainty-adjusted load impacts for the average PG&E AMP ***DA*** and ***DO*** events respectively. Hourly load impacts were 34 percent of the reference load of about 246 MW

for DO in the single hour (HE 16) in which all DO product types and events overlapped. The 10th and 90th percentile uncertainty-adjusted load impacts are estimated to be about 6 percent below and above the estimated load impacts for the average DA event, and 5 percent for the overlapping hour in the average DO event.

Table 4-37: Hourly Load Impacts – *PG&E Average AMP DA Event*

Table removed for confidentiality reasons.

Table 4-38: Hourly Load Impacts – *PG&E Average AMP DO Event*

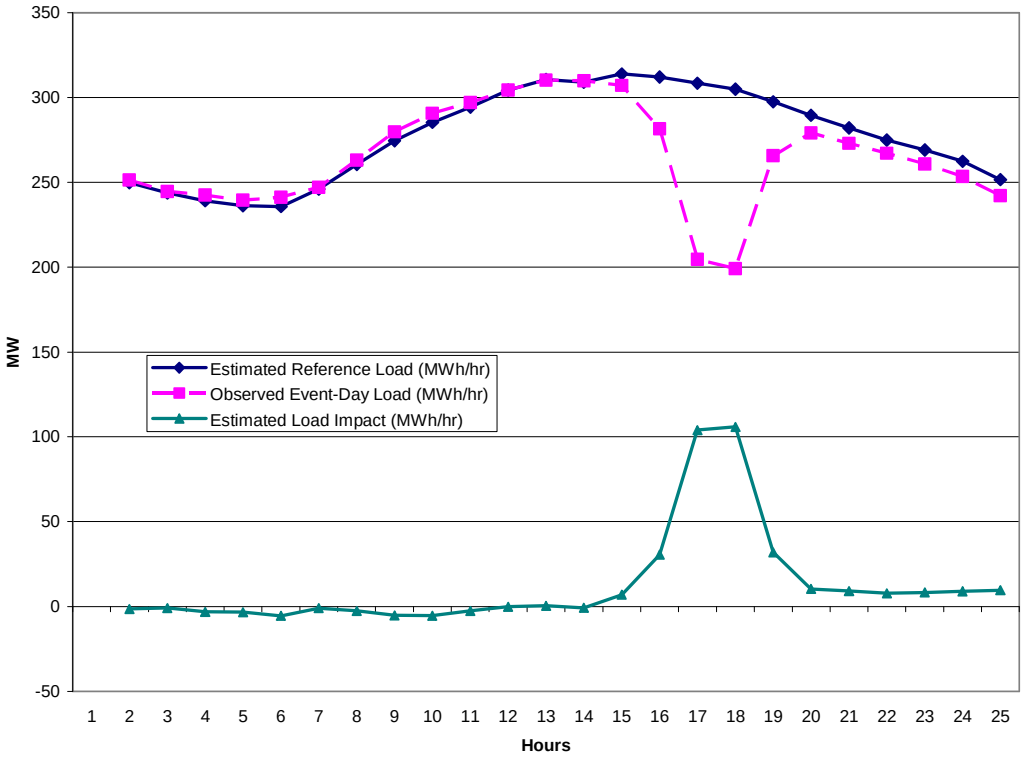
Hour Ending	Estimated Reference Load (MWh/hr)	Observed Event-Day Load (MWh/hr)	Estimated Load Impact (MWh/hr)	Weighted Average Temperature (°F)	Uncertainty Adjusted Impact (MWh/hr) - Percentiles				
					10th%ile	30th%ile	50th%ile	70th%ile	90th%ile
1	249.8	251.3	-1.5	77	-5.1	-3.0	-1.5	-0.1	2.1
2	243.8	244.7	-0.9	76	-4.5	-2.4	-0.9	0.6	2.7
3	239.2	242.4	-3.2	76	-6.8	-4.7	-3.2	-1.7	0.4
4	236.2	239.5	-3.3	75	-6.9	-4.8	-3.3	-1.8	0.3
5	235.7	241.2	-5.5	74	-9.1	-7.0	-5.5	-4.0	-1.8
6	246.0	247.0	-1.0	73	-4.7	-2.5	-1.0	0.5	2.6
7	260.5	263.1	-2.6	73	-6.2	-4.1	-2.6	-1.1	1.0
8	274.5	279.8	-5.3	74	-8.9	-6.8	-5.3	-3.8	-1.6
9	285.3	290.6	-5.3	77	-9.0	-6.8	-5.3	-3.9	-1.7
10	294.3	297.0	-2.6	80	-6.2	-4.1	-2.6	-1.1	1.0
11	304.3	304.4	-0.1	83	-3.7	-1.6	-0.1	1.4	3.5
12	310.6	310.2	0.4	86	-3.2	-1.1	0.4	1.9	4.0
13	309.1	309.9	-0.8	88	-4.4	-2.3	-0.8	0.6	2.7
14	313.9	307.0	6.9	90	3.3	5.4	6.9	8.3	10.4
15	312.1	281.6	30.5	91	26.9	29.0	30.5	31.9	34.0
16	308.5	204.5	103.9	92	100.4	102.5	103.9	105.4	107.5
17	305.0	199.1	105.8	92	102.3	104.4	105.8	107.3	109.4
18	297.5	265.6	31.9	91	28.3	30.4	31.9	33.4	35.5
19	289.5	279.2	10.3	89	6.7	8.8	10.3	11.7	13.8
20	282.0	272.9	9.1	87	5.5	7.6	9.1	10.5	12.6
21	274.9	267.1	7.8	84	4.2	6.3	7.8	9.2	11.4
22	269.0	260.8	8.2	81	4.6	6.7	8.2	9.6	11.8
23	262.3	253.3	9.0	79	5.4	7.5	9.0	10.5	12.6
24	251.6	242.1	9.5	77	6.0	8.1	9.5	11.0	13.1
	Reference Energy Use (MWh)	Observed Event-Day Energy Use (MWh)	Change in Energy Use (MWh)	Cooling Degree Hours (Base 75° F)	Uncertainty Adjusted Impact (MWh/hr) - Percentiles				
					10th	30th	50th	70th	90th
Daily	6,656	6,355	301	172.3	n/a	n/a	n/a	n/a	n/a

Figure 4–7 illustrates the reference load, observed load, and estimated load impacts for the typical AMP DA event, while Figure 4–8 illustrates comparable information for the typical DO event.

Figure 4-7: Hourly Loads and Load Impacts – *Average AMP DA Event*

Figure removed for confidentiality reasons.

Figure 4-8: Hourly Loads and Load Impacts – *Average AMP DO Event*



4.5 DRC – SCE

4.5.1 Summary load impacts

Tables 4–39 and 4–40 report estimated *average hourly* reference loads, observed loads, and load impacts by event for SCE's two DRC events. For the DA product type, the typical event is defined as the average of those two events. For DRC DO, the typical event is defined as the August 25 event, since all available aggregators were called for that event, while one was not called for the July event. Average hourly load impacts for the typical event were 8.7 MW for DA, and 113.3 MW for DO. The estimated DA load impacts are substantially below the contract levels, while DO load impacts are at about two-thirds of contract levels.

Table 4-39: Average Hourly Load Impacts by Event – *SCE DRC DA*

Event	Date	Day of Week	SAIDs Called	Estimated Reference Load (MW)	Observed Load (MW)	Estimated Load Impact (MW)	% Load Impact	Contract Load Impact (MW)
1	July 28, 2010	Wednesday	136	39.4	29.2	10.2	26%	45
2	August 25, 2010	Wednesday	140	43.3	36.0	7.2	17%	50
	Average		138	41.3	32.6	8.7	21%	
	Standard Deviation			2.8	4.8	2.1	6%	

Table 4-40: Average Hourly Load Impacts by Event – *SCE DRC DO*

Event	Date	Day of Week	SAIDs Called	Estimated Reference Load (MW)	Observed Load (MW)	Estimated Load Impact (MW)	% Load Impact	Contract Load Impact (MW)
1	July 28, 2010	Wednesday	746	246.6	162.6	84.0	34%	144
2	August 25, 2010	Wednesday	938	343.1	229.8	113.3	33%	172
Typical			938	343.1	229.8	113.3	33%	

Tables 4–41 and 4–42 report estimated *average hourly* load impacts for the typical event by industry group. Load impacts for both DA and DO are spread across a number of industry groups.

Table 4-41: Average Hourly Load Impacts by Industry Group – *SCE DRC DA*

Industry Group	SAIDs Called	Estimated Reference Load (MW)	Observed Load (MW)	Estimated Load Impact (MW)	% Load Impact
1. Agriculture, Mining & Construction	24	3.9	1.1	2.8	71%
2. Manufacturing	5	2.5	1.1	1.3	54%
3. Wholesale, Transport, other Utilities	17	10.4	7.8	2.6	25%
4. Retail stores	86	23.6	21.6	1.9	8%
5. Offices, Hotels, Health, Services	1	0.1	0.1	0.0	3%
6. Schools	4	0.4	0.4	(0.0)	-2%
7. Entertainment, Other Services, Gov't	2	0.5	0.4	0.1	14%
8. Other/Unknown					
Total	138	41.3	32.6	8.7	21%

Table 4-42: Average Hourly Load Impacts by Industry Group – *SCE DRC DO*

Industry Group	SAIDs Called	Estimated Reference Load (MW)	Observed Load (MW)	Estimated Load Impact (MW)	% Load Impact
1. Agriculture, Mining & Construction	26	4.9	3.1	1.8	36%
2. Manufacturing	80	51.2	29.5	21.7	42%
3. Wholesale, Transport, other Utilities	350	76.6	27.1	49.6	65%
4. Retail stores	420	144.2	124.1	20.0	14%
5. Offices, Hotels, Health, Services	45	28.5	12.8	15.7	55%
6. Schools	13	35.8	32.1	3.8	10%
7. Entertainment, Other Services, Gov't	4	1.9	1.0	0.9	47%
8. Other/Unknown					
Total	938	343.1	229.8	113.3	33%

Tables 4–43 and 4–44 report average hourly load impacts for the typical event by LCA for the DA and DO product types. Most of the load impacts are in the LA Basin.

Table 4-43: Average Hourly Load Impacts by LCA – *SCE DRC DA*

LCA	SAIDs Called	Estimated Reference Load (MW)	Observed Load (MW)	Estimated Load Impact (MW)	% Load Impact
1. LA Basin	110	36.6	28.4	8.2	22%
2. Outside LA Basin	10	1.8	1.6	0.2	10%
3. Ventura	19	3.0	2.6	0.4	13%
Total	138	41.3	32.6	8.7	21%

Table 4-44: Average Hourly Load Impacts by LCA – *SCE DRC DO*

LCA	SAIDs Called	Estimated Reference Load (MW)	Observed Load (MW)	Estimated Load Impact (MW)	% Load Impact
1. LA Basin	736	268.8	180.7	88.1	33%
2. Outside LA Basin	106	22.4	12.8	9.6	43%
3. Ventura	96	51.8	36.2	15.6	30%
Total	938	343.1	229.8	113.3	33%

4.5.2 Hourly load impacts

Tables 4–45 and 4–46 show average event-hour load impacts for SCE's DRC DA and DO product types across both events. Event-hour load impacts for DA ranged from 7.3 to 10.1 MW across event hours HE 15 – 17. Percentage load impacts were 22 to 26 percent, and load impacts per called customer ranged from 57 to 75 kW.

For DO, event-hour load impacts for HE 15 and 16 were 89.8 and 91.5 MW respectively, representing about 35 percent of the reference load. Average event-hour load impacts per called customer were about 120 kW.

Table 4-45: Average Event-Hour Load Impacts – *SCE DRC DA*

Hour Ending	Number of SAIDs Called	Estimated Reference Load (MW)	Observed Load (MW)	Estimated Load Impact (MW)	Weighted Average Temp (^{o}F)	# of Events this Hour is included	Load Impact per Called Customer (kW)	% Load Impact
15	136	39.5	29.4	10.1	82	1	74.5	26%
16	133	36.2	27.4	8.7	85	2	65.9	24%
17	129	32.9	25.6	7.3	86	1	56.7	22%

Table 4-46: Average Event-Hour Load Impacts – *SCE DRC DO*

Hour Ending	Number of SAIDs Called	Estimated Reference Load (MW)	Observed Load (MW)	Estimated Load Impact (MW)	Weighted Average Temp (°F)	# of Events this Hour is included	Load Impact per Called Customer (kW)	% Load Impact
15	762	261.6	171.8	89.8	86	2	118.9	34%
16	762	262.1	170.6	91.5	86	2	121.3	35%

Tables 4–47 and 4–48 show hourly reference load, observed load, load impact values, and uncertainty-adjusted load impacts for the typical SCE DRC ***DA*** and ***DO*** events respectively. Hourly load impacts ranged from 17 to 25 percent of the reference load of about 41 MW for the DA product type, and about 33 percent of the reference load of 343 MW for DO in hours 15 and 16. The 10th and 90th percentile uncertainty-adjusted load impacts are estimated to span about 8 to 12 percent below and above the estimated load impacts for the average DA event, and were about 4.5 percent for the typical DO event.

Table 4-47: Hourly Load Impacts – *Average SCE DRC DA Event*

Hour Ending	Estimated Reference Load (MWh/hr)	Observed Event-Day Load (MWh/hr)	Estimated Load Impact (MWh/hr)	Weighted Average Temperature (°F)	Uncertainty Adjusted Impact (MWh/hr) - Percentiles				
					10th%ile	30th%ile	50th%ile	70th%ile	90th%ile
1	23.2	22.7	0.5	72	-0.4	0.1	0.5	0.8	1.3
2	22.3	21.8	0.5	71	-0.4	0.1	0.5	0.9	1.4
3	21.6	21.2	0.4	71	-0.5	0.0	0.4	0.8	1.3
4	21.6	21.2	0.4	70	-0.4	0.1	0.4	0.8	1.3
5	22.1	21.8	0.3	69	-0.6	0.0	0.3	0.7	1.2
6	22.7	22.3	0.4	69	-0.5	0.0	0.4	0.7	1.3
7	23.6	23.3	0.3	69	-0.6	0.0	0.3	0.7	1.2
8	25.7	25.6	0.1	71	-0.7	-0.2	0.1	0.5	1.0
9	28.5	28.9	-0.4	74	-1.2	-0.7	-0.4	0.0	0.5
10	33.8	34.2	-0.5	78	-1.3	-0.8	-0.5	-0.1	0.4
11	38.3	38.4	-0.1	81	-0.9	-0.4	-0.1	0.3	0.8
12	39.6	39.2	0.4	84	-0.4	0.1	0.4	0.8	1.3
13	40.7	39.4	1.3	86	0.5	1.0	1.3	1.7	2.2
14	41.4	38.5	2.9	87	2.0	2.5	2.9	3.2	3.7
15	41.5	34.3	7.1	88	6.3	6.8	7.1	7.5	8.0
16	41.2	30.9	10.3	88	9.4	9.9	10.3	10.6	11.1
17	40.7	33.1	7.6	88	6.7	7.3	7.6	8.0	8.5
18	39.9	36.7	3.2	86	2.3	2.8	3.2	3.6	4.1
19	39.2	37.7	1.5	84	0.6	1.2	1.5	1.9	2.4
20	39.2	38.6	0.6	81	-0.2	0.3	0.6	1.0	1.5
21	38.2	37.9	0.4	78	-0.5	0.0	0.4	0.7	1.2
22	31.7	31.4	0.3	77	-0.6	0.0	0.3	0.7	1.2
23	26.8	26.3	0.4	75	-0.5	0.1	0.4	0.8	1.3
24	24.5	24.5	0.1	74	-0.8	-0.3	0.1	0.4	0.9
	Reference Energy Use (MWh)	Observed Event-Day Energy Use (MWh)	Change in Energy Use (MWh)	Cooling Degree Hours (Base 75° F)	Uncertainty Adjusted Impact (MWh/hr) - Percentiles				
					10th	30th	50th	70th	90th
Daily	768	730	38	110.5	n/a	n/a	n/a	n/a	n/a

Table 4-48: Hourly Load Impacts – *Typical SCE DRC DO Event*

Hour Ending	Estimated Reference Load (MWh/hr)	Observed Event-Day Load (MWh/hr)	Estimated Load Impact (MWh/hr)	Weighted Average Temperature (°F)	Uncertainty Adjusted Impact (MWh/hr) - Percentiles				
					10th%ile	30th%ile	50th%ile	70th%ile	90th%ile
1	282.9	278.6	4.3	74	-0.4	2.4	4.3	6.2	9.0
2	276.3	274.8	1.5	73	-3.2	-0.4	1.5	3.4	6.2
3	270.4	269.9	0.5	72	-4.2	-1.4	0.5	2.4	5.2
4	269.3	271.4	-2.2	72	-6.8	-4.1	-2.2	-0.3	2.5
5	273.2	275.7	-2.5	71	-7.2	-4.4	-2.5	-0.6	2.2
6	282.7	286.6	-4.0	71	-8.6	-5.9	-4.0	-2.0	0.7
7	296.9	299.3	-2.4	71	-7.1	-4.3	-2.4	-0.5	2.3
8	308.7	310.3	-1.6	73	-6.3	-3.5	-1.6	0.3	3.1
9	324.1	329.2	-5.2	77	-9.8	-7.1	-5.2	-3.2	-0.5
10	334.3	346.3	-11.9	82	-16.6	-13.8	-11.9	-10.0	-7.2
11	345.4	357.8	-12.4	87	-17.1	-14.3	-12.4	-10.5	-7.7
12	346.7	357.0	-10.3	89	-15.0	-12.2	-10.3	-8.4	-5.6
13	343.4	346.5	-3.1	92	-7.8	-5.0	-3.1	-1.2	1.6
14	345.1	319.8	25.3	93	20.6	23.4	25.3	27.2	30.0
15	342.9	229.9	113.0	92	108.4	111.1	113.0	115.0	117.7
16	343.3	229.7	113.6	92	109.0	111.7	113.6	115.5	118.3
17	343.5	306.1	37.4	91	32.8	35.5	37.4	39.3	42.1
18	341.0	325.5	15.5	89	10.8	13.6	15.5	17.4	20.2
19	345.9	338.4	7.5	87	2.8	5.6	7.5	9.4	12.2
20	350.3	346.7	3.6	84	-1.1	1.7	3.6	5.5	8.3
21	349.6	342.9	6.7	81	2.0	4.8	6.7	8.6	11.4
22	335.6	327.9	7.7	79	3.0	5.7	7.7	9.6	12.3
23	310.8	306.4	4.4	77	-0.3	2.4	4.4	6.3	9.0
24	293.6	288.1	5.6	76	0.9	3.7	5.6	7.5	10.3

	Reference Energy Use (MWh)	Observed Event-Day Energy Use (MWh)	Change in Energy Use (MWh)	Cooling Degree Hours (Base 75° F)	Uncertainty Adjusted Impact (MWh/hr) - Percentiles				
					10th	30th	50th	70th	90th
Daily	7,656	7,365	291	166.4	n/a	n/a	n/a	n/a	n/a

Figure 4–9 illustrates the reference load, observed loads, and load impacts for the average DA event, while Figure 4–10 illustrates comparable information for the typical DO event.

Figure 4-9: Hourly Loads and Load Impacts – Average SCE DRC DA Event

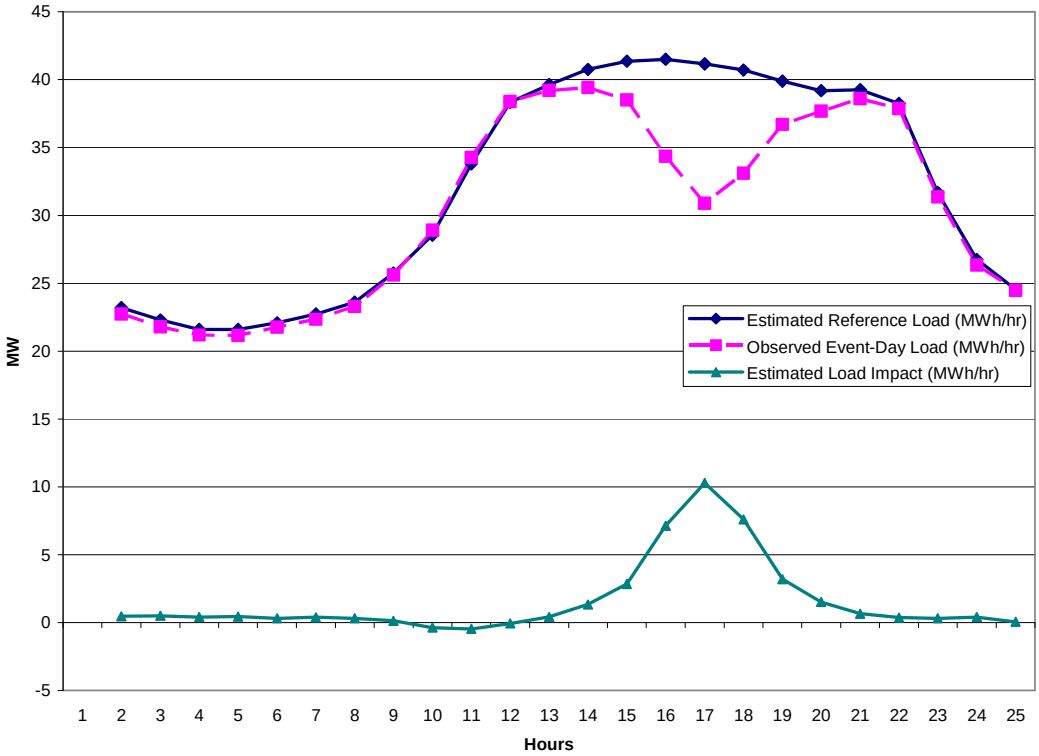
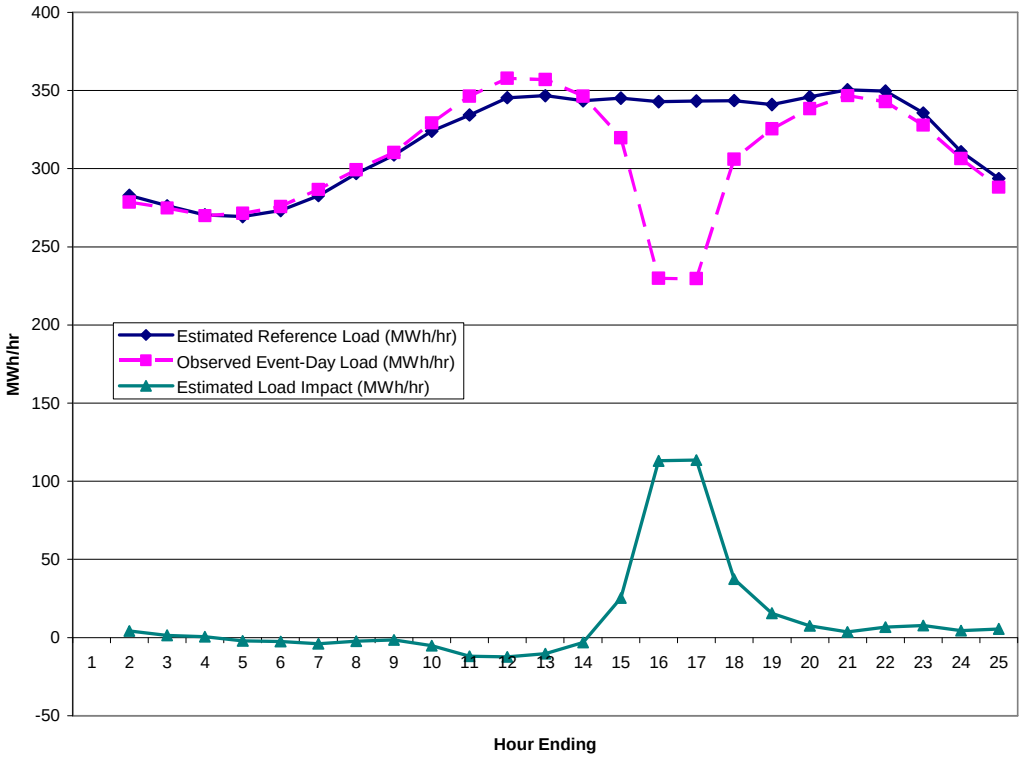


Figure 4-10: Hourly Loads and Load Impacts – *Typical SCE DRC DO Event*



4.6 DSP – SDG&E

4.6.1 Summary load impacts

Table 4–49 reports estimated *average hourly* reference loads, observed loads, and load impacts by event for SDG&E's DSP events. Average hourly load impacts were consistent across events, averaging 7.8 MW, or 33 percent of the estimated reference load, and reached nearly 10 MW on the second to last event. Table 4–50 reports estimated *average hourly* load impacts for the average event by industry group. More than half of the load impacts were provided by schools.

Table 4-49: Average Hourly Load Impacts by Event – *SDG&E DSP DO*

Event	Date	Day of Week	SAIDs Called	Estimated Reference Load (MW)	Observed Load (MW)	Estimated Load Impact (MW)	% Load Impact
1	July 14, 2010	Wednesday	83	21.5	12.9	8.6	40%
2	July 15, 2010	Thursday	83	21.9	14.0	7.9	36%
3	July 16, 2010	Friday	83	20.4	13.3	7.1	35%
4	August 17, 2010	Tuesday	99	22.4	15.4	7.1	31%
5	August 18, 2010	Wednesday	99	24.2	16.5	7.7	32%
6	August 19, 2010	Thursday	99	23.8	16.4	7.3	31%
7	August 23, 2010	Monday	99	22.4	15.6	6.8	30%
8	August 24, 2010	Tuesday	99	25.9	16.7	9.2	36%
9	August 25, 2010	Wednesday	99	26.5	16.7	9.8	37%
10	September 27, 2010	Monday	103	29.4	23.2	6.2	21%
	Average		95	23.8	16.1	7.8	33%
	Standard Deviation			2.7	2.9	1.1	5%

Table 4-50: Average Hourly Load Impacts by Industry Type – *SDG&E DSP DO*

Industry Group	SAIDs Called	Estimated Reference Load (MW)	Observed Load (MW)	Estimated Load Impact (MW)	% Load Impact
1. Agriculture, Mining & Construction					
2. Manufacturing	14	2.7	1.7	1.1	38%
3. Wholesale, Transport, other Utilities	21	2.7	1.5	1.1	42%
4. Retail stores	21	3.9	3.1	0.8	20%
5. Offices, Hotels, Health, Services	11	2.8	2.3	0.5	17%
6. Schools	24	10.8	6.5	4.3	40%
7. Entertainment, Other Services, Gov't	3	0.9	0.8	0.0	4%
8. Other/Unknown					
Total	95	23.8	16.1	7.8	33%

4.6.2 Hourly load impacts

Table 4–51 shows average event-hour load impacts for SDG&E's DSP DO program. Event-hour load impacts ranged narrowly from 6.7 to 7.8 MW across all event hours, representing percentage load impacts of 31 to 33 percent, and load impacts per called customer ranged from 69 to 83 kW.

Table 4-51: Average Event-Hour Load Impacts – *SDG&E DSP DO*

Hour Ending	Number of SAIDs Called	Estimated Reference Load (MW)	Observed Load (MW)	Estimated Load Impact (MW)	Weighted Average Temp (°F)	# of Events this Hour is included	Load Impact per Called Customer (kW)	% Load Impact
14	92	24.5	16.9	7.6	82	7	82.9	31%
15	95	25.2	17.4	7.8	83	10	82.5	31%
16	95	23.9	16.1	7.8	82	10	82.4	33%
17	94	22.1	14.7	7.4	81	8	78.7	33%
18	97	20.5	13.8	6.7	80	6	69.0	33%

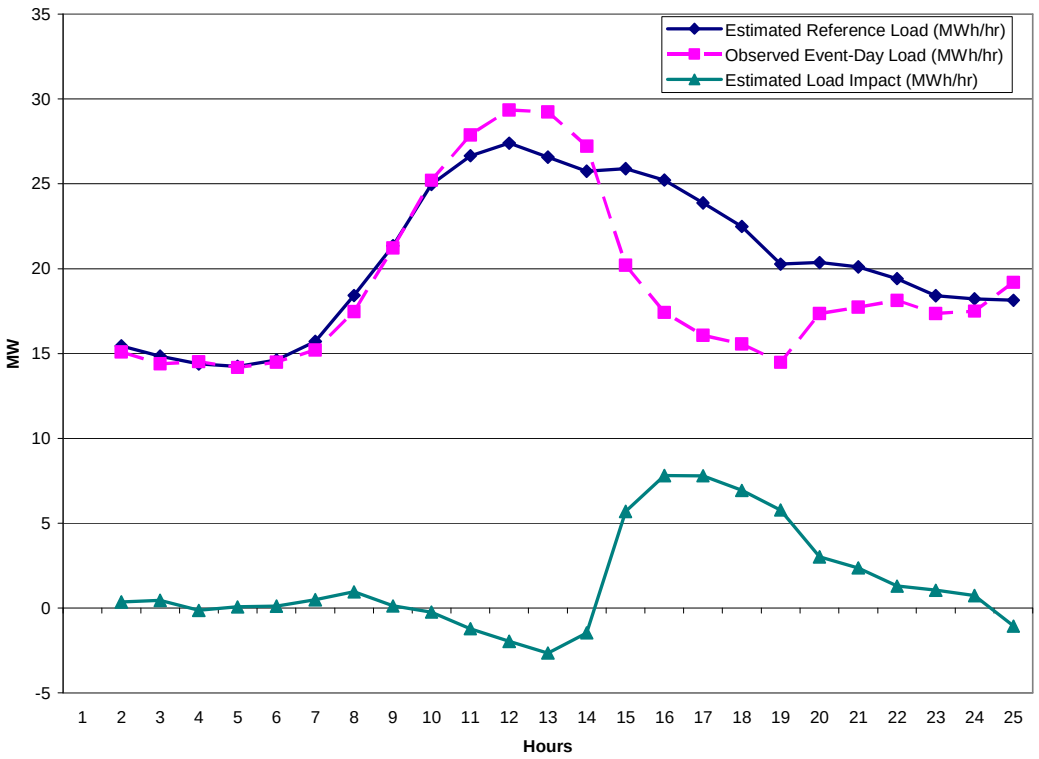
Table 4–52shows hourly reference load, observed load, load impact values, and uncertainty-adjusted load impacts for the average DSP event. Hourly load impacts ranged from 31 to 33 percent of the reference load of about 25 MW in hours 15 and 16. The 10th and 90th percentile uncertainty-adjusted load impacts are estimated to be 41 percent below and above the estimated load impact for the average event.

Table 4-52: Hourly Load Impacts – *Average SDG&E DSP DO Event*

Hour Ending	Estimated Reference Load (MWh/hr)	Observed Event-Day Load (MWh/hr)	Estimated Load Impact (MWh/hr)	Weighted Average Temperature (°F)	Uncertainty Adjusted Impact (MWh/hr) - Percentiles				
					10th%ile	30th%ile	50th%ile	70th%ile	90th%ile
1	15.5	15.1	0.4	68	-2.8	-0.9	0.4	1.7	3.5
2	14.8	14.4	0.5	68	-2.7	-0.8	0.5	1.7	3.6
3	14.4	14.5	-0.1	67	-3.3	-1.4	-0.1	1.2	3.0
4	14.2	14.2	0.1	68	-3.1	-1.2	0.1	1.4	3.2
5	14.6	14.5	0.1	67	-3.0	-1.2	0.1	1.4	3.3
6	15.7	15.2	0.5	67	-2.7	-0.8	0.5	1.8	3.7
7	18.4	17.5	1.0	69	-2.2	-0.4	1.0	2.3	4.1
8	21.3	21.2	0.1	72	-3.1	-1.2	0.1	1.4	3.4
9	25.0	25.2	-0.2	77	-3.5	-1.6	-0.2	1.1	3.0
10	26.7	27.9	-1.2	80	-4.5	-2.6	-1.2	0.1	2.0
11	27.4	29.4	-2.0	82	-5.2	-3.3	-2.0	-0.6	1.3
12	26.6	29.2	-2.7	82	-5.9	-4.0	-2.7	-1.3	0.6
13	25.7	27.2	-1.5	83	-4.7	-2.8	-1.5	-0.1	1.8
14	25.9	20.2	5.7	83	2.5	4.4	5.7	7.0	8.9
15	25.2	17.4	7.8	83	4.6	6.5	7.8	9.1	11.0
16	23.9	16.1	7.8	82	4.6	6.5	7.8	9.1	11.0
17	22.5	15.6	6.9	81	3.7	5.6	6.9	8.3	10.2
18	20.3	14.5	5.8	79	2.5	4.5	5.8	7.1	9.0
19	20.4	17.3	3.0	76	-0.2	1.7	3.0	4.3	6.3
20	20.1	17.7	2.4	74	-0.9	1.0	2.4	3.7	5.6
21	19.4	18.1	1.3	72	-1.9	0.0	1.3	2.6	4.5
22	18.4	17.4	1.1	71	-2.2	-0.3	1.1	2.4	4.3
23	18.2	17.5	0.7	71	-2.5	-0.6	0.7	2.0	3.9
24	18.1	19.2	-1.1	70	-4.3	-2.4	-1.1	0.3	2.2
	Reference Energy Use (MWh)	Observed Event-Day Energy Use (MWh)	Change in Energy Use (MWh)	Cooling Degree Hours (Base 75° F)	Uncertainty Adjusted Impact (MWh/hr) - Percentiles				
					10th	30th	50th	70th	90th
Daily	493	456	36	62.9	n/a	n/a	n/a	n/a	n/a

Figure 4–11 illustrates the reference load, observed loads, and load impacts for the average DSP event.

Figure 4–11: Hourly Loads and Load Impacts – *Average SDG&E DSP DO Event*



4.7 Average Event-Hour Load Impacts per Enrolled Customer

Table 4–53 provides summary indicators of average event-hour load impacts *per called customer* for each program and product type.

Table 4-53: Average Event-Hour Load Impacts per Called Customer (kW)

	DA	DO
PG&E CBP	26.0	78.2
SCE CBP	11.0	48.1
SDG&E CBP	80.3	32.6
AMP	202.0	238.2
DRC	65.9	120.1
DSP	-	79.8

4.8 Concentrations of Load Impacts Across Customers

To illustrate the extent to which overall load impacts are concentrated in relatively small numbers of customers, Table 4–54 reports the percentages of load and load impacts that are accounted for by the top 5 percent of customers with the largest load impacts in each program at each utility. The concentration of load impacts varies considerably across

programs and product types (DA/DO), but is similar to findings reported in previous evaluations. That is, nearly half or more of total load impacts are accounted for by those 5 percent of customers with the largest load impacts in a number of programs and product types. Two exceptions are SCE's two CBP product types, where load impacts are spread more evenly across customers. The top 5 percent of customers also typically account for large portions of the total load in the program (often accounting for about a third of the total), which indicates that they are larger than average. However, the share of load impacts is often twice as large as the share of load, indicating that these customers also provide relatively larger load impacts than the average customer of the same size.

Table 4-54: Percentages of Load and Load Impacts Accounted for by Top 5% of Customers, by Program and Utility

	% of Load	% of Load Impacts
CBP - DA		
PG&E	32%	74%
SCE	4%	12%
SDG&E	38%	85%
CBP - DO		
PG&E	21%	30%
SCE	7%	17%
SDG&E	11%	34%
Contract - DA		
AMP (PGE)	35%	64%
DRC (SCE)	34%	48%
Contract - DO		
AMP (PGE)	23%	59%
DRC (SCE)	34%	48%
DSP (SDGE)	50%	69%

4.9 Auto-DR and TA/TI Impacts

This section reports the estimated *ex post* load impacts achieved by 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 objective of the TA portion of the program is to subsidize customer energy audits that can help customers identify ways to participate in DR and modify their usage patterns. The TI portion of the program then provides incentive payments for the installation of equipment or control software to support DR.

The Automated Demand Response (Auto-DR) 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 even eliminated during times of high electricity prices or electricity system emergencies.[15]

For each utility aggregator program that had TA/TI or AutoDR participants, we present two tables of information. The first table contains the *total* estimated reference loads and load impacts, by event, provided by those service accounts who have participated in TA/TI or AutoDR.[16] The second table compares, where possible, the average percentage load impacts achieved by TA/TI or AutoDR participants in particular industry types to those of comparable groups of non-participating service accounts, to the extent that such groups exists. In cases where no other customer accounts for the same industry are available, results for service accounts in a particular industry type are compared to other service accounts of the same "customer" that did not participate in an incentive program. In other cases, percentage load impacts are compared to those of other customer accounts in the same industry type.

In these tables, each row of data shows the percentage load impacts and number of customer-events for customers within a 6-digit NAICS code or a 4-digit SIC code. Where possible, we conduct comparisons of load impacts within these highly disaggregated industry groups. Where a comparison at this level of disaggregation is not possible, we may compare at a higher level of industry aggregation, such as 2-digit SIC codes or 3-digit NAICS codes. In some cases, the list of service accounts does not contain any reasonable basis of comparison for the participating TA/TI or AutoDR service account. (These cases are denoted as "No Comparables" in the tables.)

We note that the above comparisons do not constitute a formal evaluation of the incremental effect of AutoDR or TA/TI on customers' demand response load impacts. This is the case largely due to generally small numbers of observations and a lack of complete customer and technology information. For example, we rarely observe "before and after" load responses for the same service account. In addition, enabling technology of the type installed through AutoDR and TA/TI may in fact be used by some SAIDs that did not participate in either incentive program. Therefore, we cannot be certain that when we compare TA/TI and non-TA/TI accounts we are actually measuring a "with and without" technology difference.[17] However, given the available data, we believe that the comparisons made in this section are informative and the most relevant ones to provide.

[15] A process evaluation conducted in conjunction with the 2008 load impact evaluation of the aggregator programs provides useful information on the operation of the programs and the perspectives of the participating customers on the enrollment process, their stated approach for responding to events, and the type of technology that they or their aggregator may have installed to facilitate responding to events called (see below). See "2008 Process Evaluation of California Statewide Aggregator Demand Response Programs," prepared by Research Into Action, August 6, 2009.

[16] Our understanding is that the TA/TI and AutoDR participation data are cumulative, in that the data for 2010 include customer accounts that participated in previous years, as well as those new in 2010.

[17] Customer surveys undertaken in the 2008 process evaluation found that 40 percent of surveyed participants reported that their facilities had an energy management or building control system prior to the enrollment with their aggregator. Fifteen percent of participants reported installing new equipment before participating, and 42 percent reported that their aggregator had installed new equipment after their enrollment (the equipment was often described as some additional metering technology designed to provide the customer or aggregator with access to timely energy usage information.

4.9.1 PG&E

Table 4–55 shows the estimated load impacts for a typical CBP DO event for two TA/TI service accounts on PG&E CBP DO. Those account's load impacts averaged 103 kW across the last two events, in which both participated. Table 4–56 indicates that one of the accounts, a supermarket, averaged similar but slightly smaller load impacts (4.5 percent compared to 5.8 percent) over all seven DO events compared to other accounts for that same customer.

Table 4–55: Total TA/TI Load Impacts by Event – *PG&E CBP DO*

Event	Number of SAIDs	Estimated Reference Load (kW)	Observed Load (kW)	Estimated Load Impact (kW)	% Load Impact
Typical	2	3,344	3,241	103.1	3.1%

Table 4–56: *Incremental* TA/TI Load Impacts – *PG&E CBP DO*

NAICS Code	NAICS Description	Basis of Comparison	Percentage Load Impact		Number of Customer-Events	
			TA/TI	No TA/TI	TA/TI	No TA/TI
112120	Dairy Cattle and Milk Production	No comparables	3.1%	na	2	na
445110	Supermarkets and Other Grocery Stores	Different accounts for same customer	4.5%	5.8%	7	231

Table 4–57 shows total estimated reference loads and load impacts for 53 TA/TI service accounts enrolled in PG&E's AMP day-of program. Load impacts amounted to 13.3 MW on the July test event for which all 53 TA/TI accounts participated.

Table 4–57: Total TA/TI Load Impacts by Event – *PG&E AMP DO*

Event Date	Number of SAIDs	Estimated Reference Load (kW)	Observed Load (kW)	Estimated Load Impact (kW)	% Load Impact
7/16/2010	53	38,491	25,175	13,316	34.6%
8/25/2010	4	3,306	2,995	310	9.4%

Table 4–58 compares percentage load impacts for TA/TI and non-TA/TI service accounts in similar six-digit NAICS industry types. In all cases the TA/TI accounts show larger percentage load impacts than do the non-TA/TI accounts.

Table 4–58: *Incremental* TA/TI Load Impacts – *PG&E AMP DO*

NAICS Code	NAICS Description	Basis of Comparison	Percentage Load Impact		Number of Customer-Events	
			TA/TI	No TA/TI	TA/TI	No TA/TI
115114	Post-harvest crop activities	Different accounts; same industry	48.6%	45.9%	1	42
312130	Wineries	Different accounts; same industry	55.6%	49.5%	5	37
327320	Ready-mix concrete manuf.	Different accounts for same customer	85.0%	33.7%	2	5
331511	Iron foundaries	Different accounts for same customer	11.2%	5.6%	1	1
334511	Analytical laboratory instrument manufacturing	Different accounts; same industry	14.2%	-0.1%	1	6
452112	Discount dept. stores	Different accounts for same customer	21.6%	9.1%	11	44

4.9.2 SCE

Table 4–59 shows counts of participating customer accounts, total estimated average hourly reference loads, load impacts and percent load impacts (LI), by event, for TA/TI and AutoDR participants in SCE's CBP DO product type. For comparability, results are also shown for customer accounts that did not participate in either incentive program. Estimated load impacts for AutoDR and TA/TI participants averaged 0.7 MW and 3.5 MW respectively, compared to non-participant load impacts of 10.2 MW.

Table 4–59: Total TA/TI and AutoDR Load Impacts by Event – *SCE CBP DO*

	Program											
	Auto-DR				TI				None			
Event	SAIDs	Reference Load (kW)	Load Impact (kW)	%LI	SAIDs	Reference Load (kW)	Load Impact (kW)	%LI	SAIDs	Reference Load (kW)	Load Impact (kW)	%LI
1	28	9,561	520	5.4%	135	18,074	3,598	19.9%	142	49,060	4,550	9.3%
2	28	9,799	220	2.2%	135	18,344	3,314	18.1%	142	49,305	8,917	18.1%
3	28	10,405	189	1.8%	135	18,894	3,751	19.9%	142	50,387	10,703	21.2%
4												
5												
6												
7												
8	14	4,533	424	9.3%	136	18,316	3,168	17.3%	14	57,439	14,137	24.6%
9	14	4,556	285	6.3%	136	18,361	3,138	17.1%	14	58,776	1,520	2.6%
10	14	4,663	570	12.2%	136	18,716	3,168	16.9%	14	57,242	15,399	26.9%
11												
12												
13												
14												
15												
16	45	18,239	1,845	10.1%	136	15,450	4,203	27.2%	45	48,290	13,074	27.1%
17	45	17,305	1,340	7.7%	136	14,645	3,432	23.4%	45	45,399	12,934	28.5%
18												
19												
Typical	27	9,883	674	6.8%	136	17,600	3,471	19.7%	70	51,987	10,154	19.5%
Per Cust		366	25.0	6.8%		130	25.6	19.7%		745	145.6	19.5%

Table 4–60 shows differences in estimated percentage load impacts for CBP DO TA/TI participants and non-participants (where available) by 4-digit SIC code for five different industries. The table also reports the total numbers of customer-events in which the various sets of customers participated. In three of the four industries for which comparisons can be made, the TA/TI accounts had larger average load impacts than the non-TA/TI accounts.

Table 4–60: Incremental TA/TI Load Impacts – *SCE CBP DO*

SIC Code	SIC Description	Basis of Comparison	Percentage Load Impact		Number of Customer-Events	
			TA/TI	No TA/TI	TA/TI	No TA/TI
5211	Home Center Stores	Diff. accounts; diff. customers	34.3%	20.7%	16	1,030
5331	Variety Stores	No comparables	29.1%		585	
5411	Grocery Stores	Diff. accounts; same customer	12.5%	0.5%	160	16
5943	Stationery Stores	Diff. accounts; diff. customers	24.5%	33.8%	78	141
7991	Physical Fitness Facilities	Diff. accounts; same customer	8.3%	7.7%	204	45

Table 4–61 reports comparable information for AutoDR participants. For the one industry for which a comparison may be made, the AutoDR participants produced somewhat larger percentage load impacts than non-participants.

Table 4–61: Incremental AutoDR Load Impacts – *SCE CBP DO*

SIC Code	SIC Description	Basis of Comparison	Percentage Load Impact		Number of Customer-Events	
			AutoDR	No AutoDR	AutoDR	No AutoDR
5311	Department Stores	No comparables	8.7%		117	
7991	Physical Fitness Facilities	Diff. accounts; same customer	11.1%	7.7%	54	45

Table 4–62 reports total estimated reference loads and load impacts by event for TA/TI and AutoDR participants in SCE's DRC DO product type. Estimated load impacts average about 1.4 MW and 12 MW for AutoDR and TA/TI participants respectively.

Table 4–62: Total TA/TI and AutoDR Load Impacts by Event – *SCE DRC DO*

	Program											
	Auto-DR				TA/TI				None			
Event	SAIDs	Reference Load (kW)	Load Impact (kW)	%LI	SAIDs	Reference Load (kW)	Load Impact (kW)	%LI	SAIDs	Reference Load (kW)	Load Impact (kW)	%LI
1	5	2,444	1,443	59%	192	64,080	12,229	19%	562	181,299	71,217	39%
2	5	3,154	1,357	43%	190	74,105	11,538	16%	575	204,731	85,291	42%
Average Per Cust		560	280	50%		362	62	17%		340	138	41%

Table 4–63 shows comparisons of percentage load impacts for DRC DO TA/TI participants in the eleven industry types that they represent. In four of the nine industries for which comparisons were possible, the TA/TI participants showed larger percentage load impacts than the non-TA/TI accounts, while in the other five industries the opposite was true.

Table 4–63: Incremental TA/TI Load Impacts – *SCE DRC DO*

SIC Code	SIC Description	Basis of Comparison	Percentage Load		Number of	
			TA/TI	No TA/TI	TA/TI	No TA/TI
2011, 26, 37, 41, 48	Food processing	Diff. accounts; diff. customers	50%	20%	6	11
4222	Refrigerated warehousing	Diff. accounts; diff. customers	24%	89%	3	8
4812	Cellular communications	Diff. accounts; diff. customers	17%	-5%	10	2
4941	Water supply	Diff. accounts; diff. customers	42%	74%	16	545
5148 & sim.	Grocery products	Diff. accounts; diff. customers	7%	14%	2	4
5311	Department stores	Diff. accounts; diff. customers	14%	11%	99	70
5411	Grocery stores	Diff. accounts; diff. customers	14%	16%	236	74
7011	Hotels	Diff. accounts; diff. customers	2%	37%	4	52
8051	Nursing care facility	No comparables	26%		2	
8222	Colleges & univ.	Diff. accounts; diff. customers	10%	9%	2	20
8422	Botanical gardens	No comparables	50%		2	

Table 4–64 shows comparable information for two industry types for AutoDR participants. In this case, the AutoDR particpants showed substantially larger percentage load impacts than the comparable non-AutoDR accounts.

Table 4–64: Incremental AutoDR Load Impacts – *SCE DRC DO*

SIC Code	SIC Description	Basis of Comparison	Percentage Load		Number of	
			AutoDR	No AutoDR	AutoDR	No AutoDR
723	Crop preparation	Diff. accounts; diff. customers	59%	23%	8	46
2011, 26, 37, 41, 48	Food processing	Diff. accounts; diff. customers	38%	20%	2	11

4.9.3 SDG&E

Tables 4–65 and 4–66 show total average hourly estimated reference loads, load impacts and percent load impacts (LI) for TA/TI and AutoDR participants in SDG&E's CBP DA and DO product types respectively. For comparability, results are also shown for customer accounts that did not participate in either incentive program. For the DA product type, the eight AutoDR and two TA/TI participants accounted for average hourly load impacts of 0.15 MW and 0.56 MW respectively. For the DO product type, the seventy AutoDR and seven TA/TI participants accounted for average hourly load impacts of 0.9 MW and 0.07 MW respectively. The estimated load reductions for the TA/TI customer accounts showed substantial variability in load impacts across events, ranging from 0.25 MW load reductions to comparably sized event-day load *increases*.

Table 4–65: Total TA/TI and AutoDR Load Impacts by Event – *SDG&E CBP DA*

	Program								
	Auto-DR			TA/TI			None		
Event	Reference Load (kW)	Load Impact (kW)	%LI	Reference Load (kW)	Load Impact (kW)	%LI	Reference Load (kW)	Load Impact (kW)	%LI
1									
2									
3	1,226	92	7.5%	6,235	339	5.4%	26,769	9,357	35.0%
4									
5	1,309	147	11.3%	6,399	561	8.8%	26,981	8,012	29.7%
6	1,165	92	7.9%	5,997	474	7.9%	8,974	918	10.2%
7									
8	1,282	186	14.5%	6,663	642	9.6%	27,222	8,974	33.0%
9	1,220	78	6.4%	6,450	481	7.5%	26,788	8,065	30.1%
10	1,204	94	7.8%	6,268	353	5.6%	26,745	9,773	36.5%
11									
12	1,342	275	20.5%	6,737	977	14.5%	22,327	9,468	42.4%
13									
Typical	1,264	145	11.5%	6,459	559	8.7%	26,139	8,941	34.2%
Per Cust	631.9	72.7	11.5%	807.3	69.8	8.7%	257.9	88.2	34.2%
SA_IDs		2			8			101	

Table 4–66: Total TA/TI and AutoDR Load Impacts by Event – *SDG&E CBP DO*

	Program								
	Auto-DR			TA/TI			None		
Event	Reference Load (kW)	Load Impact (kW)	%LI	Reference Load (kW)	Load Impact (kW)	%LI	Reference Load (kW)	Load Impact (kW)	%LI
1	7,003	602	8.6%	466	247	52.9%	50,695	7,542	14.9%
2	7,169	927	12.9%	478	113	23.7%	51,788	7,847	15.2%
3	7,173	1,247	17.4%	435	247	56.8%	53,679	8,268	15.4%
4	5,429	792	14.6%	412	217	52.6%	51,860	7,549	14.6%
5	5,340	747	14.0%	445	239	53.8%	51,146	6,987	13.7%
6									
7	5,351	895	16.7%	364	102	28.1%	50,760	8,226	16.2%
8	5,434	915	16.8%	376	85	22.7%	51,484	8,474	16.5%
9	5,347	761	14.2%	400	-7	-1.8%	51,674	8,273	16.0%
10	5,192	759	14.6%	423	150	35.3%	50,522	7,260	14.4%
11	7,037	859	12.2%	460	-255	-55.4%	41,155	7,295	17.7%
12	6,678	1,386	20.8%	521	-254	-48.8%	40,305	8,585	21.3%
13	6,558	1,429	21.8%	777	-92	-11.9%	39,649	5,297	13.4%
Typical	6,143	943	15.4%	463	66	14.3%	48,726	7,634	15.7%
Per Cust	88	14	15.4%	64	9	14.3%	253	40	15.7%
SA_IDs		70			7			193	

Table 4–67 compares percentage load impacts for TA/TI participants in CBP DA to those of non-participants in the same 6-digit NAICS industry type.[18] In both industries, the TA/TI participants produced larger percentage load impacts than non-participants.

Table 4–67: Incremental TA/TI Load Impacts – *SDG&E CBP DA*

NAICS Code	NAICS Description	Basis of Comparison	Percentage Load Impact		Number of Customer-Events	
			TA/TI	No TA/TI	TA/TI	No TA/TI
221122	Electric Power Distribution	Diff accnts; same industry	7.4%	-0.1%	14	7
525930	Real Estate Investment Trusts	Diff accnts; same company	6.3%	-0.1%	42	266

Table 4–68 provides similar comparisons for AutoDR participants. In the two industry types represented, the percentage load impacts for AutoDR participants and non-participants were comparable in size.

[18] The classification into "electric power distribution" appears to be for certain accounts for several different industries (*e.g.*, office buildings, hospitals, grocery stores, department stores) that represent a company's generation or distribution equipment.

Table 4–68: Incremental AutoDR Load Impacts – *SDG&E CBP DA*

NAICS Code	NAICS Description	Basis of Comparison	Percentage Load Impact		Number of Customer-Events	
			AutoDR	No AutoDR	AutoDR	No AutoDR
525930	Real Estate Investment Trusts	Diff accnts; same company	0.3%	-0.1%	7	266
531312	Nonresidential Property Managers	Diff accnts; same industry	22.6%	27.2%	7	105

Table 4–69 shows comparisons for CBP DO TA/TI participants. For the department stores, TA/TI participant percentage load impacts were substantially greater than for non-participants. For the other industry type, the percentage load impacts were about the same. Table 4–70 shows comparable results for AutoDR for eleven industry types. Of the six industries for which comparisons were possible, AutoDR participants had larger percentage load impacts than non-participants in two industries, and smaller percentage load impacts in the other four.

Table 4–69: Incremental TA/TI Load Impacts – *SDG&E CBP DO*

NAICS Code	NAICS Description	Basis of Comparison	Percentage Load Impact		Number of Customer-Events	
			TA/TI	No TA/TI	TA/TI	No TA/TI
452111	Department Stores (except Discount)	Diff accnts; same industry	48.0%	12.6%	78	300
541710	Research and Development in the Physical, Engineering, and Life Sciences	Diff accnts; same industry	10.3%	10.7%	9	63

Table 4–70: Incremental AutoDR Load Impacts – *SDG&E CBP DO*

NAICS Code	NAICS Description	Basis of Comparison	Percentage Load Impact		Number of Customer-Events	
			AutoDR	No AutoDR	AutoDR	No AutoDR
441222	Boat Dealers	No comparables	16.4%		24	
445110	Supermarkets and Other Grocery Stores	Diff accnts; same industry	6.8%	8.1%	96	660
448190	Other Clothing Stores	Diff accnts; same industry	0.5%	15.5%	27	36
452111	Department Stores (except Discount)	Diff accnts; same industry	22.4%	12.6%	402	300
512131	Motion Picture Theaters	No comparables	3.8%		12	
531312	Nonresidential Property Managers	Diff accnts; same industry	14.9%	4.1%	12	9
561439	Other Business Service Centers (including Copy Shops)	Diff accnts; same industry	10.8%	29.5%	96	12
561920	Convention and Trade Show Organizers	No comparables	11.8%		6	
713940	Fitness and Recreational Sports Centers	Diff accnts; same company	6.8%	10.0%	135	231
721110	Hotels (except Casino Hotels) and Motels	Diff accnts; same industry	8.3%		12	
812910	Pet Care (except Veterinary) Services	No comparables	20.1%		12	

5. Ex Ante Load Impacts

This section documents the preparation of ex ante forecasts of reference loads and load impacts for 2011 to 2021 for the aggregator demand response programs offered by PG&E, SCE, and SDG&E. These include CBP for all three utilities, AMP for PG&E, DRC for SCE, and DSP for SDG&E. In each case, separate load impact forecasts were developed for the *day-ahead* and *day-of* product types, where relevant.

The forecasts of load impacts were developed in two primary stages. First, estimates of reference loads and percentage load impacts, on a per-enrolled customer basis, were developed based on modified versions of the ex-post load impact regressions described in Section 4. Second, the simulated per-customer reference loads under alternative weather (*e.g.*, 1-in-2 and 1-in-10) and event-type scenarios (*e.g.*, typical event, or monthly system peak day), and the estimated percentage load impacts were combined with program enrollment forecasts from the utilities to develop alternative forecasts of aggregate load impacts. Forecasts were developed at the program and product-type (*e.g.*, DA and DO) level, and by CAISO *Local Capacity Area*. The Brattle Group provided enrollment forecasts for PG&E's programs through a separate contract. SCE and SDG&E provided enrollment forecasts for their programs.

The following subsections describe the nature of the ex ante load impact forecasts required, the methods used to produce them, detailed study findings, and recommendations.

5.1 Ex Ante Load Impact Requirements

The DR Load Impact Evaluation Protocols require that hourly load impact forecasts for event-based DR resources be reported for the following scenarios (in addition to the program-level and LCA breakdown noted above):

- 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).

5.2 Description of Methods

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

5.2.1 Development of Customer Groups

The relevant customer groups differed across the three utilities. PG&E, through its contractor The Brattle Group, creates enrollment forecasts that are differentiated by size group and local capacity area. The three size groups were the following:

- Small – maximum demand less than 20 kW;
- Medium – maximum demand between 20 and 199 kW;
- Large – maximum demand of 200 kW or greater.

SDG&E provided enrollment forecasts by notice level and duration. That is, the day-of notice customers with four- and six-hour event windows were forecast separately.[19] SCE provided total expected enrollments by program and notice level, to be used under the assumption that the customer mix remains the same as the size of the program changes.

For each utility, we developed customer-level reference loads and load impacts (for all required scenarios) that corresponded to the enrollment forecast.

[19] For both the DSP and CBP day-of enrollment forecasts, we separated out the two largest customers from the remaining customers. This prevented these "outliers" from affecting the per-customer load impacts that were combined with the enrollment forecasts.

5.2.2 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 cell and scenario
3. Calculate percentage load impacts by cell
4. Apply percentage load impacts to the reference loads
5. Scale the reference loads using enrollment forecasts

Each of these steps is described below.

1. *Define data sources*

Since no major design changes are planned for any of the aggregator programs, there is a close link between the results of the ex post analyses conducted for the 2010 program year and the ex ante load impact forecasts. That is, the historical customer loads serve as the basis of the ex ante reference loads, and the historical estimated percentage load impacts serve as the basis for constructing the ex ante load impacts.

2. *Estimate and simulate reference loads*

The objective of this step is to produce average per-customer reference loads under the various scenarios required by the Protocols (*e.g.*, the typical event day in a 1-in-2 weather year) so that they may be applied to the enrollment forecasts to produce program-level results. The required level of aggregation of the reference loads depends on the level of detail of the enrollment forecasts. For example, for SCE, where only total numbers of enrolled customers are provided, we produced a program-level reference load, where the shares of customers of each type are implicitly assumed to remain the same as in the historical year. Alternatively, if enrollment forecasts are provided by size and LCA, as for PG&E, then we produce per-customer reference loads at that level of aggregation.

To develop the reference loads, we first re-estimate regression equations for each enrolled customer account, using data for 2010. These equations are used to simulate reference loads by customer type under the alternative scenarios. These loads are then averaged at the appropriate level to produce per-customer loads.

The re-estimated regression equations are identical to the ex post load impact equations described in Section 3.1, with one exception: the ex ante models exclude the morning-usage variable. While this variable is useful for improving accuracy in estimating ex post load impacts for each event, it complicates the use of the equations in ex ante simulation. That is, it would require a separate simulation of the level of the morning load.

The regression equations contain both weather variables and monthly indicator variables, which provide the capability to simulate customer loads under the different weather and monthly system peak scenarios. The definitions of the 1-in-2 and 1-in-10 weather years differed by utility, and are the same as the definitions used in the previous report (studying the 2009 program year load impacts).

3. *Calculate forecast percentage load impacts*

The percentage load impacts were based on the 2010 ex post load impact estimates. Using these estimates was complicated by the fact that the prescribed ex ante event window (1:00 p.m. to 6:00 p.m.) is usually different from the event windows actually experienced during 2010 events. Therefore, we "re-arranged" the historical percentage load impacts to match the forecast event window. For all programs except SCE's CBP program, we retained the hourly ex post load impacts to the extent possible given the ex ante event window. For SCE's CBP program, the wide variation in event windows and notifications across events required us to estimate a separate regression model that was based on the ex post regression model with the following modification: the event-hour variables were replaced with three variables, one for event hours, one for the hours adjacent to the event hours, and one for the non-event hours on event days. This more generalized specification allowed us to consistently add load impacts across customers, regardless of the historical event windows to which they were exposed. The uncertainty-adjusted load impacts were based on the standard errors on the three event-hour-type coefficients.

Where enough event days were called, we based the uncertainty-adjusted load impacts on the variation in estimated load impacts across event days (as opposed to using the standard errors associated with the event-hour load impact estimates). This method was used for PG&E's CBP and SDG&E's CBP and DSP.

In some cases, results from a sub-set of the event days were used to calculate percentage load impacts. The events used are listed below by program.

- PG&E AMP DA and DO: only the 7/16/2010 event was used. Only a sub-set of customers was called for the subsequent re-test on 8/25/2010.
- PG&E CBP DA: we used events occurring on 7/16, 8/16. 8/24, and 8/25. These events were selected because of the stability in the level of nominated load across the event days. For CBP DO, we used all of the event days.
- SCE CBP: we used all event days, but using the hour-type variables described above.
- SCE DRC: we used results from both event days (7/28 and 9/25).
- SDG&E CBP DA: we did not use data from the 8/20 event because load impacts were affected by a communication failure that SDG&E had with one of the aggregators.
- SDG&E CBP DO: we did not use data from the last event (9/29) because it was only two hours in duration, whereas the other events ranged from four to six hours in duration (and therefore better matched the ex ante forecast window).
- SDG&E DSP: we used data for all events from 7/16 through 8/23 because the event window during these five events exactly matched the ex ante event window.

4. *Apply percentage load impacts to reference loads for each event scenario*.

In this step, the relevant percentage load impacts per enrolled customer account were applied to the per-customer reference loads for each scenario to produce all of the required

scenarios of reference loads, estimated event-day loads, and load impacts.

5. *Apply forecast enrollments to produce program-level load impacts*.

For PG&E's programs, The Brattle Group produced load impacts at the program level and by LCA by applying their enrollment forecasts to the database of *per-customer* reference loads and load impacts that CA Energy Consulting created in the previous step. The per-customer reference loads and load impacts were first scaled to match the expected *size* of customers in the enrollment forecast and then multiplied by the number of enrolled customers to obtain cell-level results. Program-level results were obtained by aggregating results across cells. We report these aggregated results in the required Protocol tables, and summarize them in Section 5.4 below.

For SCE and SDG&E, we scaled the results for all levels of reporting using enrollments specific to each program and notice level. In both cases, we assume that the distribution of customers across size groups and LCAs (for SCE) remains constant at historical levels throughout the forecast period.

5.3 Enrollment Forecasts

This section summarizes the enrollment forecasts for the different product types at each utility. The following section summarizes the resulting estimated reference loads and ex ante load impact forecasts. Detailed tables of all results required by the Protocols are provided in associated appendices.

Table 5–1 summarizes PG&E's enrollment forecasts for the DA and DO product types for CBP and AMP (as developed by The Brattle Group). After an initial modest increase through 2011, enrollment in both programs remains constant through 2021.

Table 5-1: Enrollment Forecasts – PG&E CBP and AMP

	CBP		AMP	
	DA	DO	DA	DO
Jan-11	569	277	211	574
Feb-11	603	292	196	630
Mar-11	642	310	182	693
Apr-11	687	329	169	761
May-11	738	352	157	836
Jun-11	738	352	157	836
Jul-11	738	352	157	836
Aug-11	738	352	157	836
Sep-11	738	352	157	836
Oct-11	738	352	157	836
Nov-11	738	352	157	836
Dec-11	738	352	157	836
Thru Dec 2021	738	352	157	836

Table 5–2 shows SCE's enrollment forecasts for CBP and DRC. SCE anticipates that CBP enrollment will remain flat after 2014, and the anticipated DRC contract amounts will go through 2012.

Table 5-2 Enrollment Forecasts – SCE CBP DA and DO, and DRC

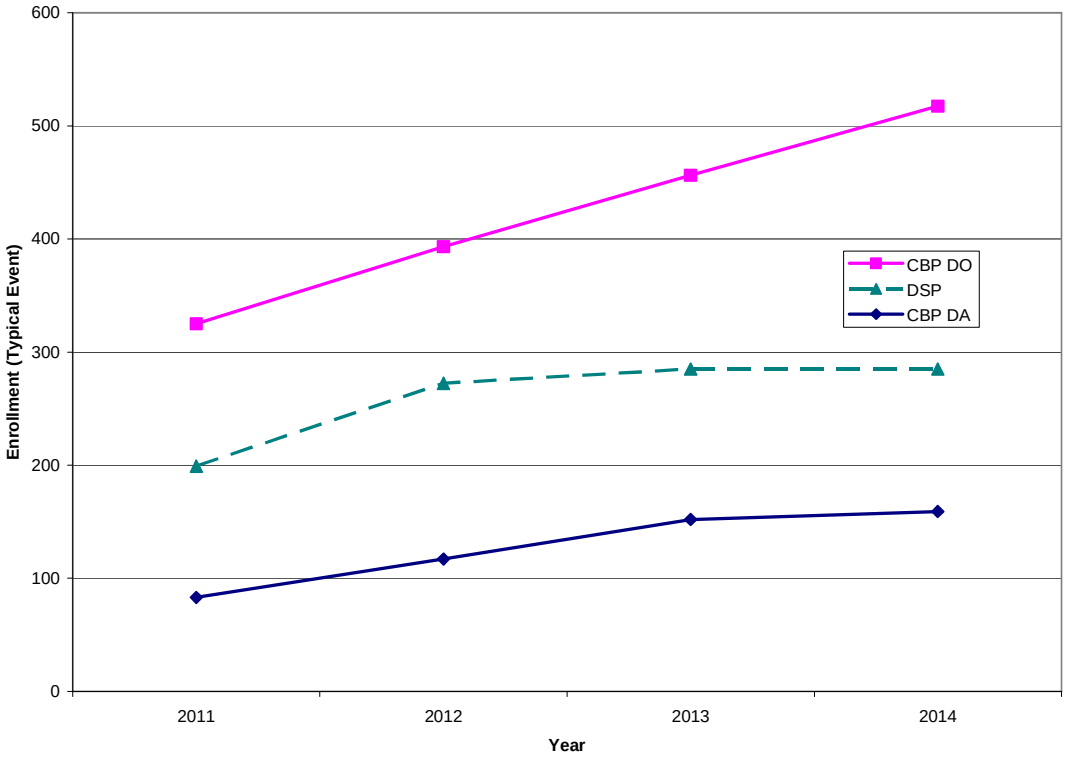
	CBP		DRC	
	DA	DO	DA	DO
2011	97	442	393	1,225
2012	115	473	380	1,192
2013	132	504	0	0
2014	150	536	0	0

Table 5–3 shows enrollment forecasts by program month and year for SDG&E's CBP DA and DO product types, as well as its DSP program. Forecasts beyond 2012 for DSP and 2014 for CBP are for enrollment to remain flat. Figure 5–1 illustrates forecast enrollment for a typical event day for 2011 to 2014.

Table 5-3 Enrollment Forecasts – SDG&E CBP DA and DO, and DSP

	2011			2012			2013			2014		
	CBP DA	CBP DO	DSP	CBP DA	CBP DO	DSP	CBP DA	CBP DO	DSP	CBP DA	CBP DO	DSP
May	83	310	172	107	378	260	145	443	285	159	504	285
June	83	316	182	110	384	265	148	448	285	159	509	285
July	83	322	192	115	390	270	150	453	285	159	515	285
August	83	328	204	119	396	275	153	459	285	159	520	285
September	83	334	216	123	402	280	156	464	285	159	525	285
October	83	340	229	128	408	285	159	469	285	159	531	285
Typical Event	83	325	199	117	393	272	152	456	285	159	517	285

Figure 5–1: Enrollment Forecasts – SDG&E CBP



5.4 Reference Loads and Load Impacts

For each utility and product type, we provide the following summary information about the load impact forecasts:

1. Figures showing the hourly profile of the reference load, event-day load, and load impacts for the typical August event day in 2012, in a 1-in-2 weather year;
2. Average event-hour load impacts by year, for a 1-in-2 and 1-in-10 weather year; and
3. The allocation of load impacts to LCA, where relevant.

Together, these figures provide useful indicators of the anticipated changes in the forecast load impacts across the various scenarios represented in the Protocol tables. All of the tables required by the Protocols are provided in a spreadsheet table generator in an Appendix.

5.4.1 PG&E – CBP and AMP

This section presents ex ante load impacts for PG&E's CBP and AMP programs. Figure 5–2 shows the forecast reference load, event-day load, and load impacts for a typical event day in August 2012 in a 1-in-2 weather year for CBP DA.[20] Event-hour load impacts

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

average 43.6 MW, which represents approximately 13.7 percent of the estimated reference load. Figure 5–3 shows comparable information for CBP DO. Event-hour load impacts for CBP DO average 36.6 MW, which represents approximately 17.7 percent of the estimated reference load.

Figure 5–2: Hourly Event-Day Load Impacts for the Typical Event Day in a 1-in-2 Weather Year for August 2012 – *PG&E CBP - DA*

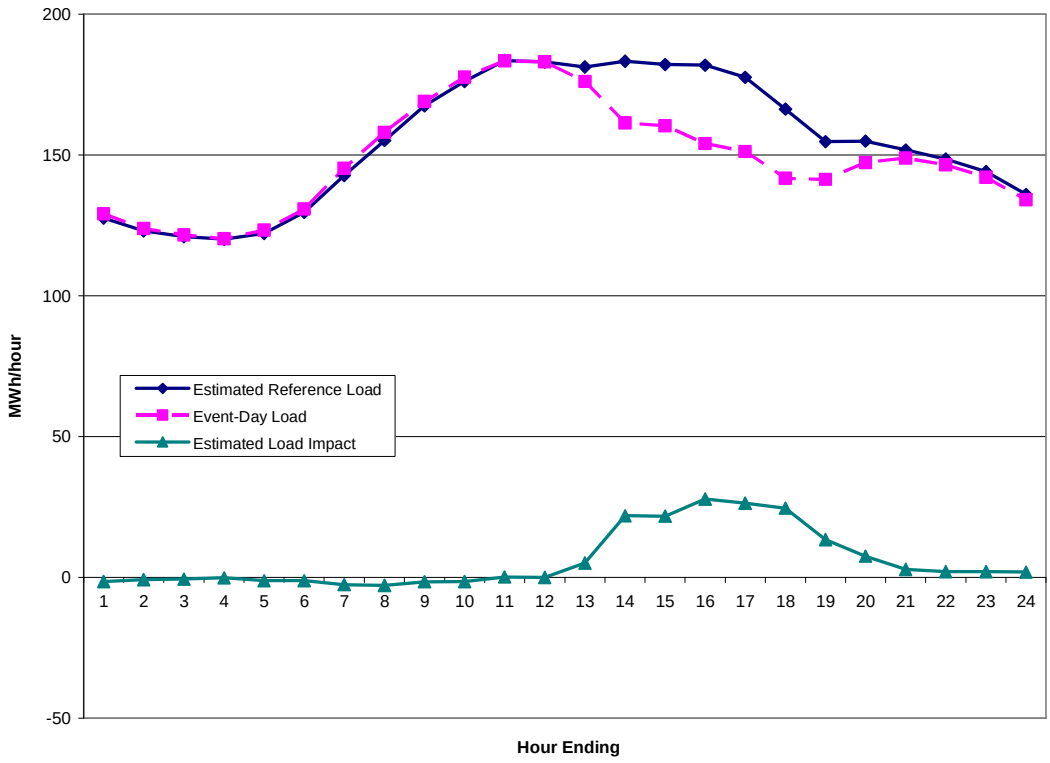
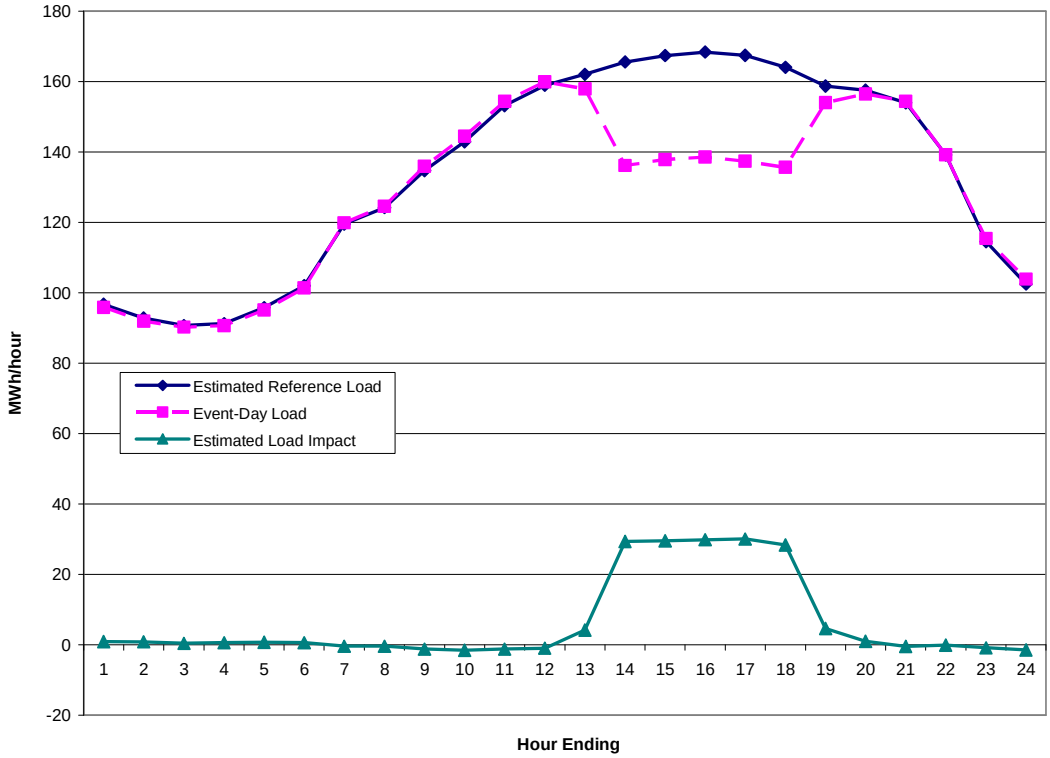


Figure 5–3: Hourly Event-Day Load Impacts for the Typical Event Day in a 1-in-2 Weather Year for August 2012 – *PG&E CBP - DO*



Figures 5–4 and 5–5 show the forecast loads and load impacts for a typical event day in August in a 1-in-2 weather year for the PG&E AMP DA and DO product types. Average event-hour load impacts are 40 MW for the DA product type and 149 MW for DO. Both represent contracted load impacts.

Figure 5–4: Hourly Event-Day Load Impacts for the Typical Event Day in a 1-in-2 Weather Year for August 2012 – *AMP - DA*

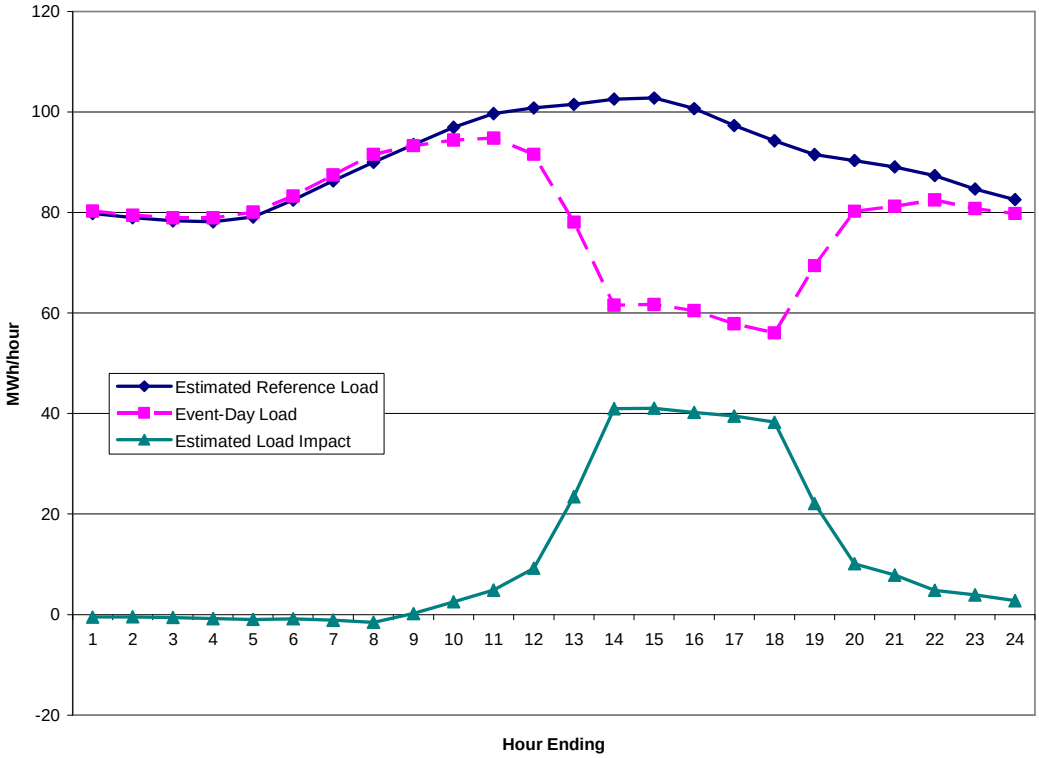


Figure 5–5: Hourly Event Day Load Impacts for the Typical Event Day in a 1-in-2 Weather Year for August 2012 – *AMP - DO*

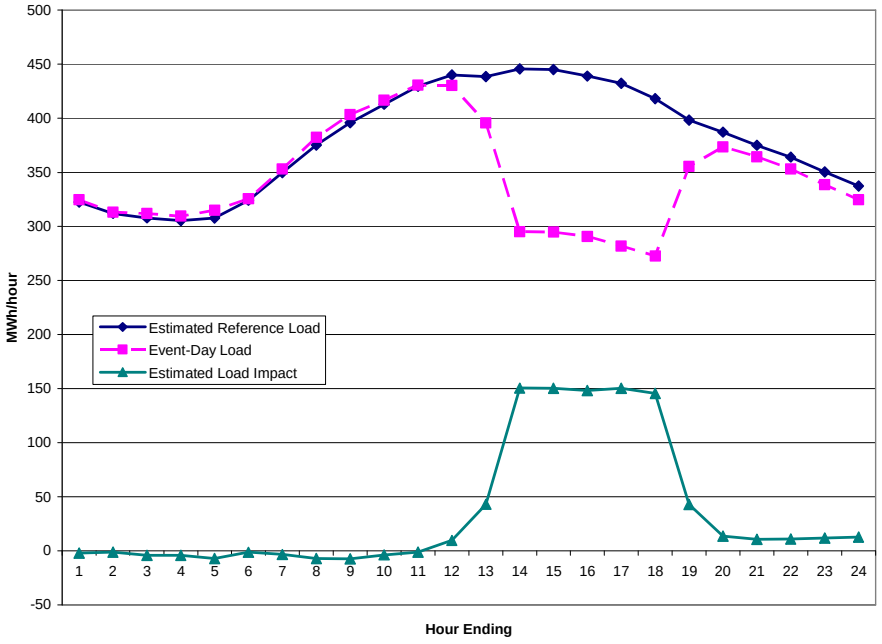


Table 5–4 reports forecasts of average event-hour load impacts for PGE's CBP and AMP programs for relevant months in 2011 and 2021, for typical event days in August, in 1-in-2 and 1-in-10 weather years.[21] The load impacts for both CBP product types are expected to plateau in 2011 and remain at those levels for the remainder of the forecast period.

Table 5–4: Average Hourly Load Impacts by Month and Year on Typical Event Day in 1-in-2 and 1-in-10 Weather Years – *PG&E CBP and AMP*

	1-in-2 Weather Year		1-in-10 Weather Year			
	CBP		CBP		AMP	
	DA	DO	DA	DO	DA	DO
Jan-11						
Feb-11						
Mar-11						
Apr-11						
May-11	22.6	25.4	24.1	27.5	40	149
Jun-11	25.2	29.1	25.7	30.1	40	149
Jul-11	25.1	29.5	25.3	29.7	40	149
Aug-11	24.7	29.8	24.6	29.7	40	149
Sep-11	24.8	29.6	25.7	30.8	40	149
Oct-11	23.7	26.6	23.6	26.9	40	149
Nov-11						
Dec-11						
Thru 2021						
May-21	22.6	25.4	24.1	27.5	40	149
Jun-21	25.2	29.1	25.7	30.1	40	149
Jul-21	25.1	29.5	25.3	29.7	40	149
Aug-21	24.7	29.8	24.6	29.7	40	149
Sep-21	24.8	29.6	25.7	30.8	40	149
Oct-21	23.7	26.6	23.6	26.9	40	149

Figure 5–6 and Figure 5–7 show forecast average event-hour load impacts by LCA for the CBP DA and DO, and AMP DA and DO product types respectively. With the exception of AMP DA, the majority of load impacts are expected to occur in the Greater Bay Area.

[21] In most cases, the monthly peak load impacts for CBP are larger in the 1-in-10 weather year scenario. However, in August, the 1-in-10 year values are slightly less than the 1-in-2 values. While this should not occur for the given set of ex post customers on which the load impacts per customer are based, as the enrollment forecasts and customer mix by LCA change over time, the small differences in the two scenarios may produce the outcome observed in the table.

Figure 5–6: Load Impacts by LCA for a Typical Event Day in August 2012 in a 1-in-2 Weather Year (*PG&E CBP DA and DO*)

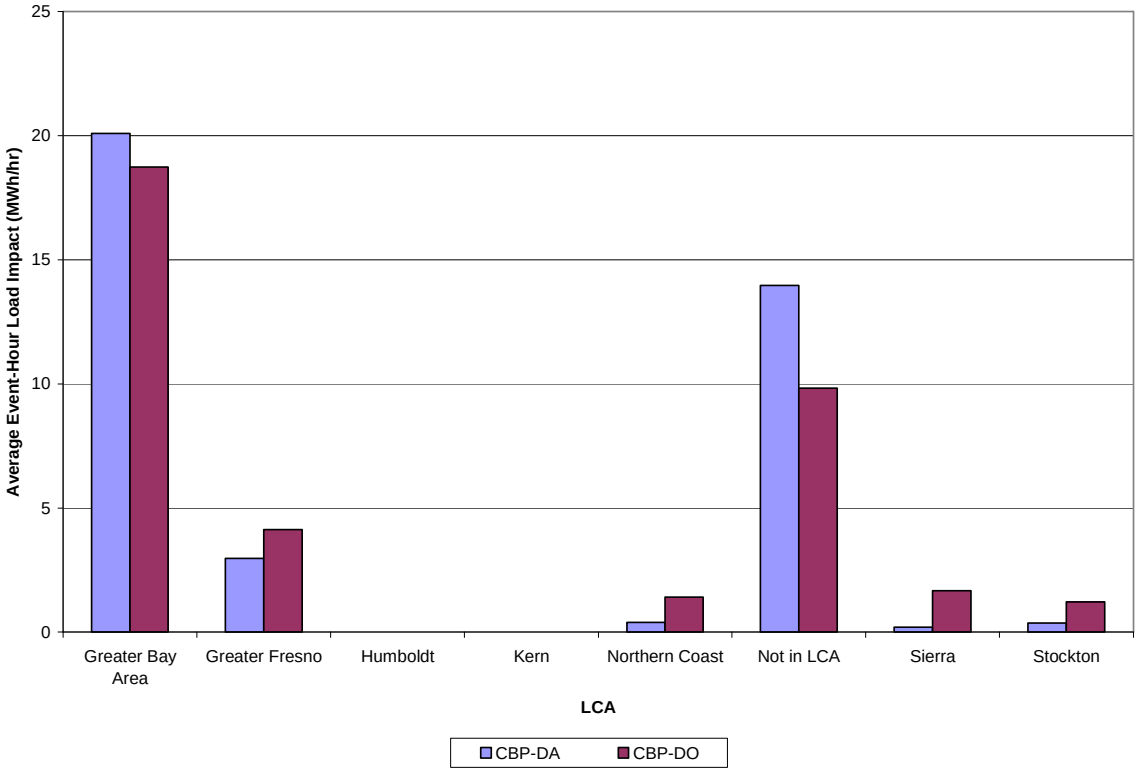
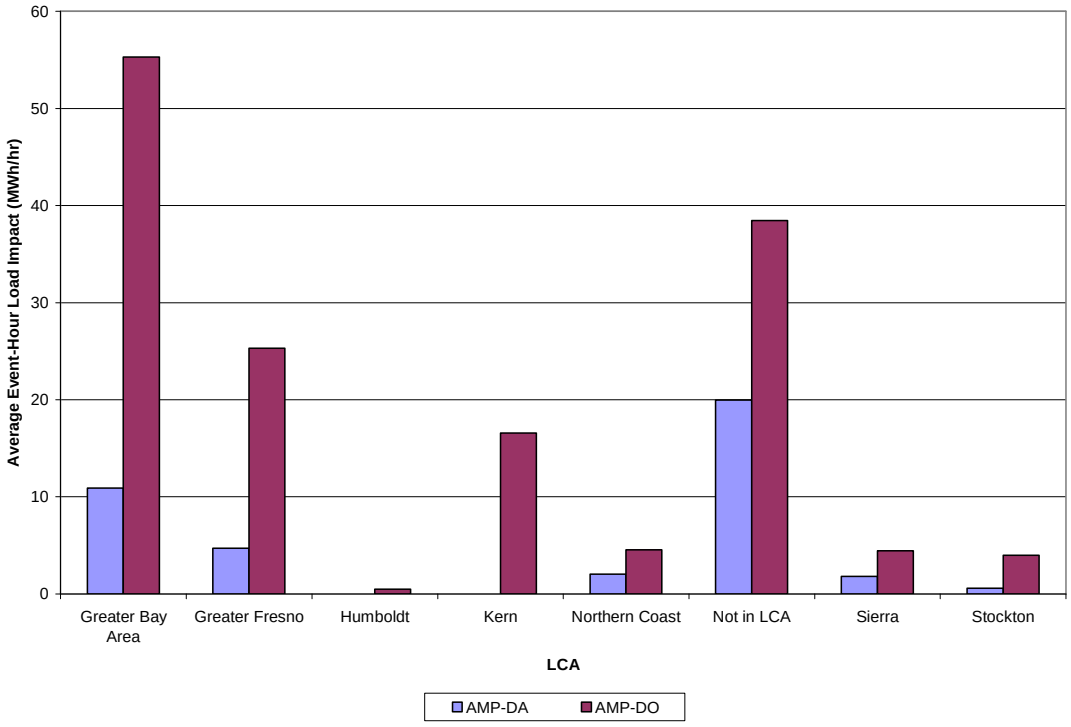


Figure 5–7: Load Impacts by LCA for the August 2012 Typical Day in a 1-in-2 Weather Year – *AMP DA and DO*



5.4.2 SCE CBP and DRC

This section presents ex ante load impacts for SCE's CBP and DRC programs. Figures 5–8 and 5–9 show the forecast reference load and load impacts for a typical event day in a 1-in-2 weather year in 2012 for the SCE CBP DA and DO product types respectively. Event-hour load impacts average about 1.2 MW for DA, which is approximately 10 percent of the enrolled reference load. DO load impacts average about 18.2 MW, or 16.6 percent of the reference load.

Figure 5-8: Hourly Event-Day Load Impacts for the Typical Event Day in a 1-in-2 Weather Year for 2012 – *SCE CBP DA*

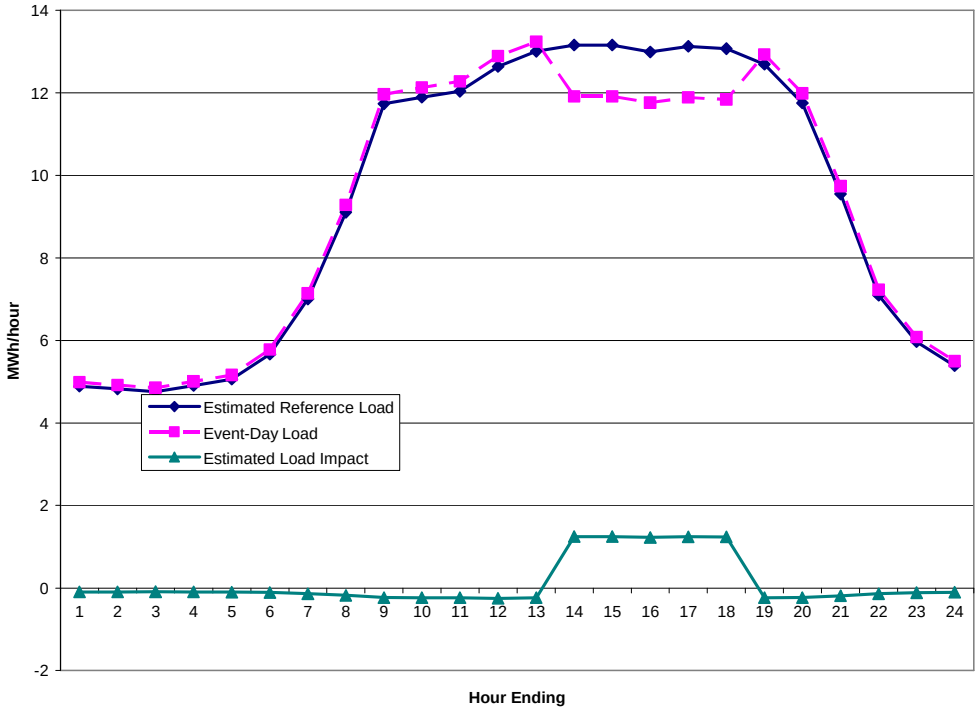
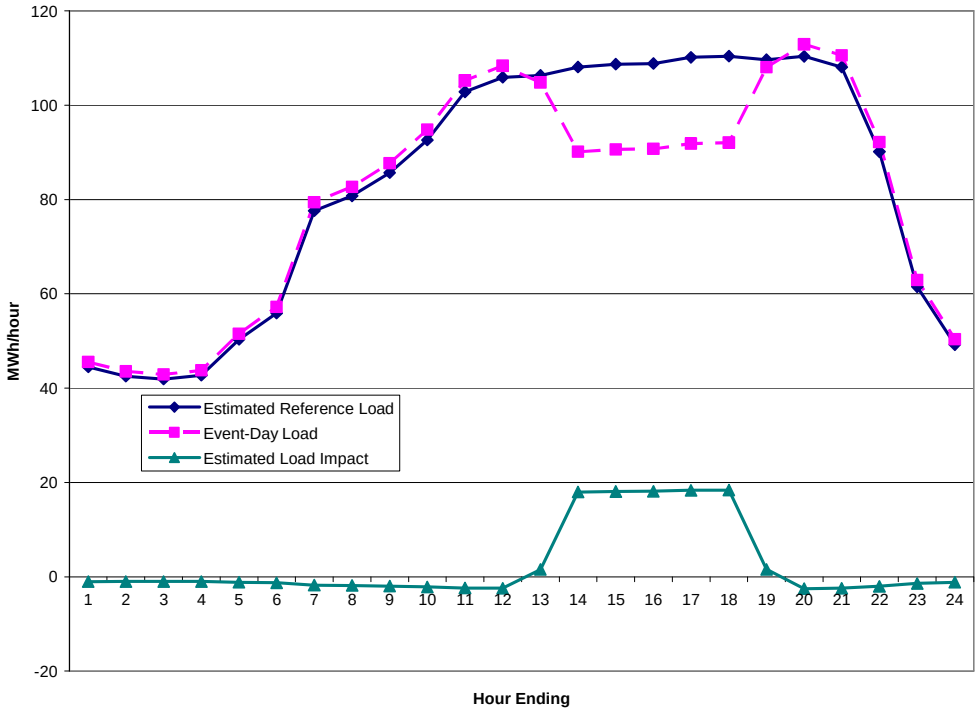


Figure 5–9: Hourly Event Day Load Impacts for the Typical Event Day in a 1-in-2 Weather Year for 2012 – *SCE CBP DO*



Figures 5–10 and 5–11 show the hourly profiles of forecast loads and load impacts for a typical event day in a 1-in-2 weather year for 2012 for SCE's DRC DA and DO product types. Event-hour load impacts average approximately 25.2 MW for DA, which is about 25 percent of the enrolled reference load. DO load impacts average 78.5 MW, which is approximately 34 percent of the enrolled reference load.

Figure 5–10: Hourly Event Day Load Impacts for the Typical Event Day in a 1-in-2 Weather Year for 2012 – *SCE DRC DA*

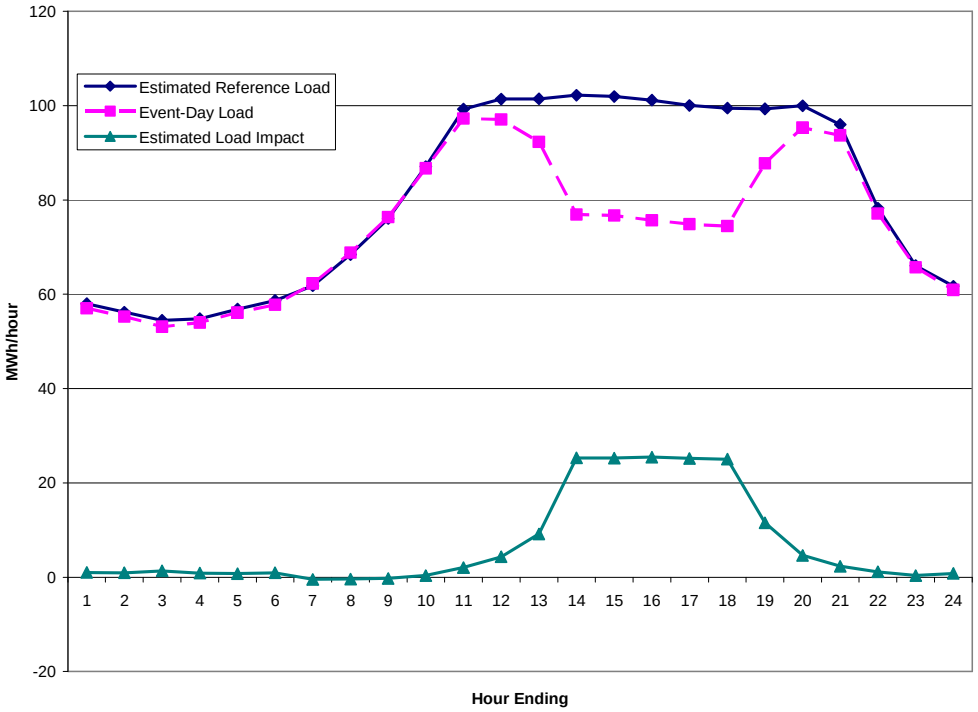


Figure 5–11: Hourly Event Day Load Impacts for the Typical Event Day in a 1-in-2 Weather Year for 2012 – *SCE DRC DO*

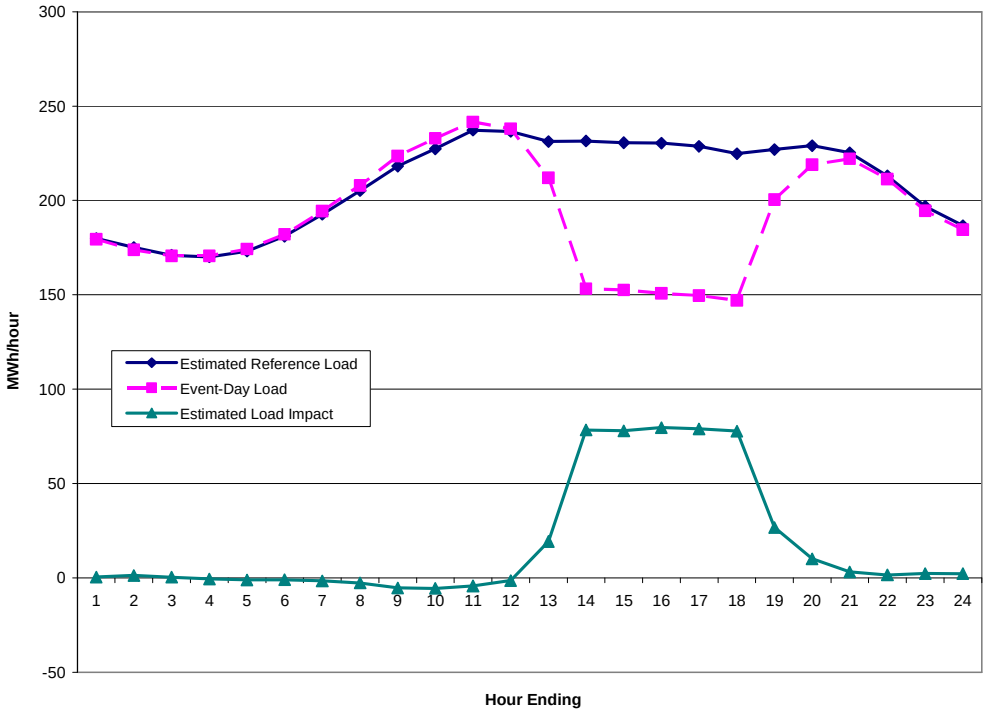


Table 5–5 reports average event-hour load impacts across the first four years of the forecast for CBP and two years for DRC, for the typical event day in 1-in-2 and 1-in-10 weather years.

Table 5–5: Average Event-Hour Load Impacts (MW) by Forecast Year for the Typical Event Day – *SCE CBP & DRC DA and DO*

	1-in-2 Weather Yr		1-in-10 Weather Yr		1-in-2 Weather Yr		1-in-10 Weather Yr	
	CBP				DRC			
Year	DA	DO	DA	DO	DA	DO	DA	DO
2011	1.0	17.0	1.1	17.1	26.1	80.7	26.3	81.1
2012	1.2	18.2	1.3	18.3	25.2	78.5	25.4	78.9
2013	1.4	19.4	1.4	19.6				
2014	1.6	20.6	1.6	20.8				

Figure 5–12 shows average event-hour load impacts by LCA for the typical event day in a 1-in-2 weather year in 2012 for CBP DA and DO. Figure 5–13 shows average event-hour load impacts for the three LCAs for DRC DA and DO. The majority of load impacts for both programs and product types occur in the LA Basin.

Figure 5–12: Average Event-Hour Load Impacts by LCA for the Typical Event Day in a 1-in-2 Weather Year in 2012 – *SCE CBP DA and DO*

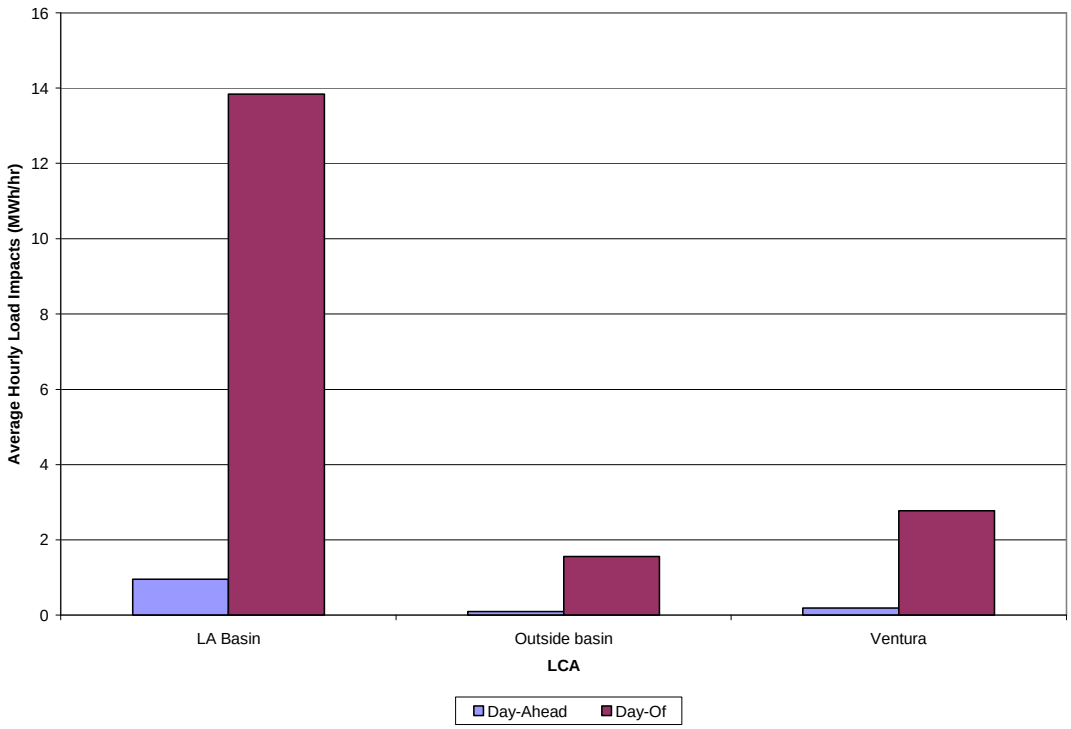
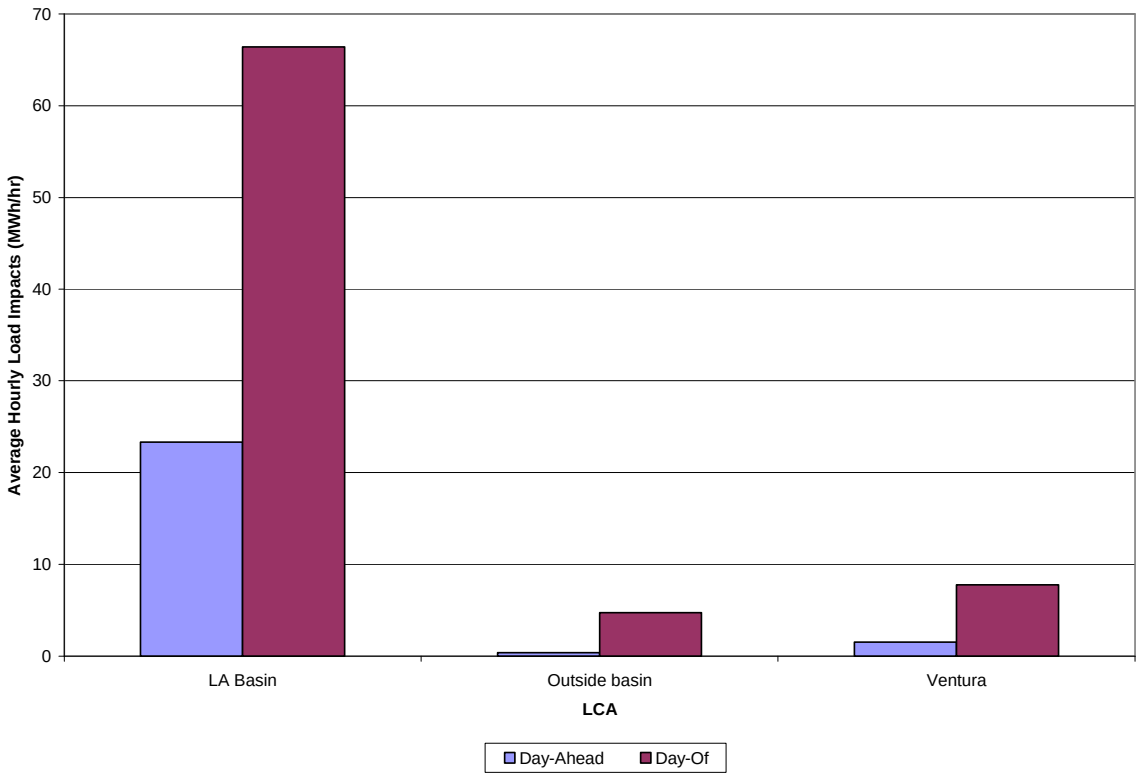


Figure 5–13: Load Impacts by LCA for the August 2012 Typical Day in a 1-in-2 Weather Year – *DRC DA and DO*



5.4.3 SDG&E CBP and DSP

Figures 5–14 and 5–15 show the forecast loads and load impacts for a typical event day in a 1-in-2 weather year for 2012 for the SDG&E CBP DA and DO product types respectively. Event-hour load impacts for DA average about 10.2 MW, which is approximately 27 percent of the enrolled reference load. DO load impacts average 18.2 MW, or 16.6 percent.

Figure 5–14: Ex Ante Load Impacts for the Typical Event Day in a 1-in-2 Weather Year for 2012 – *SDG&E CBP DA*

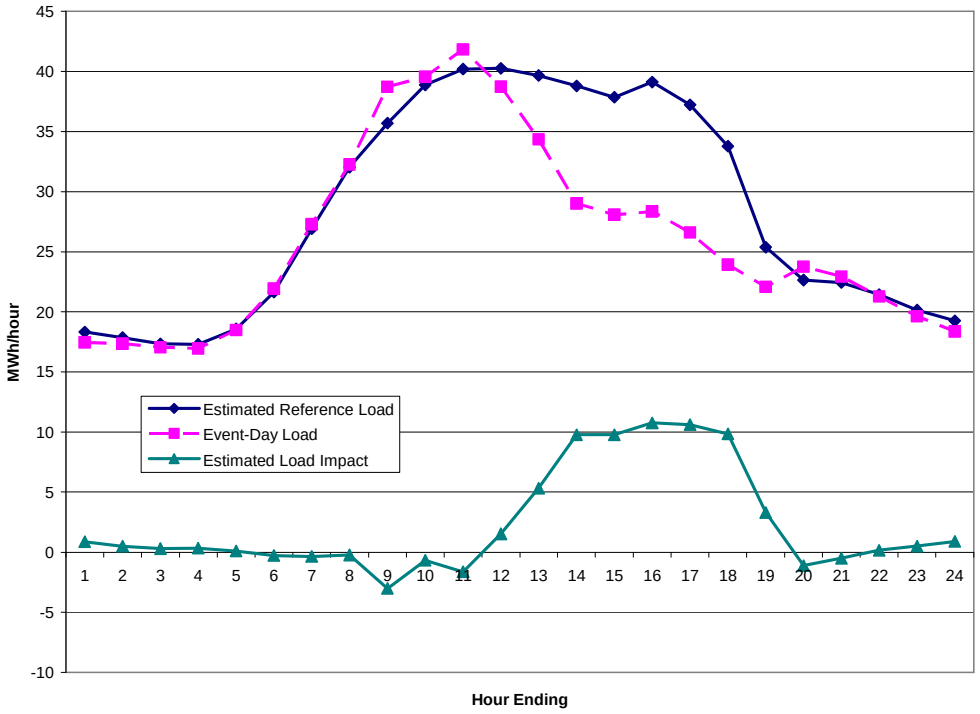


Figure 5–15: Ex Ante Load Impacts for the Typical Event Day in a 1-in-2 Weather Year for 2012 – *SDG&E CBP DO*

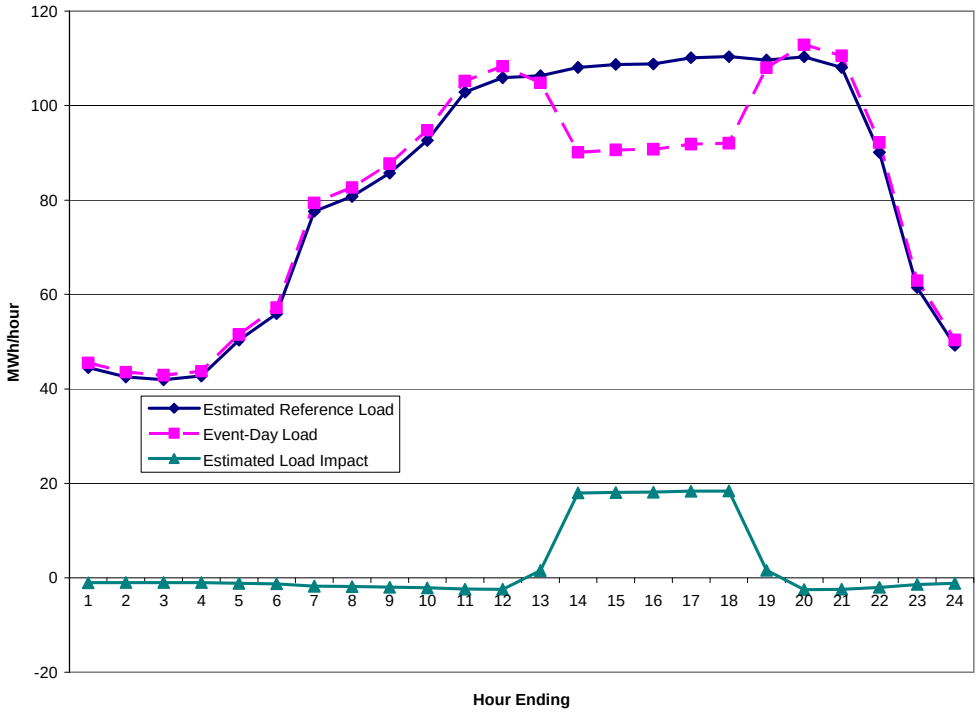


Figure 5–16 shows the hourly profiles of forecast loads and load impacts for a typical event day in a 1-in-2 weather year for 2012 for SDG&E's DSP program, which only contains the DO product type. Estimated event-hour load impacts average 14.9 MW, which is about 26 percent of the reference load.

Figure 5–16: Ex Ante Load Impacts for the Typical Event Day in a 1-in-2 Weather Year for 2012 – *SDG&E DSP*

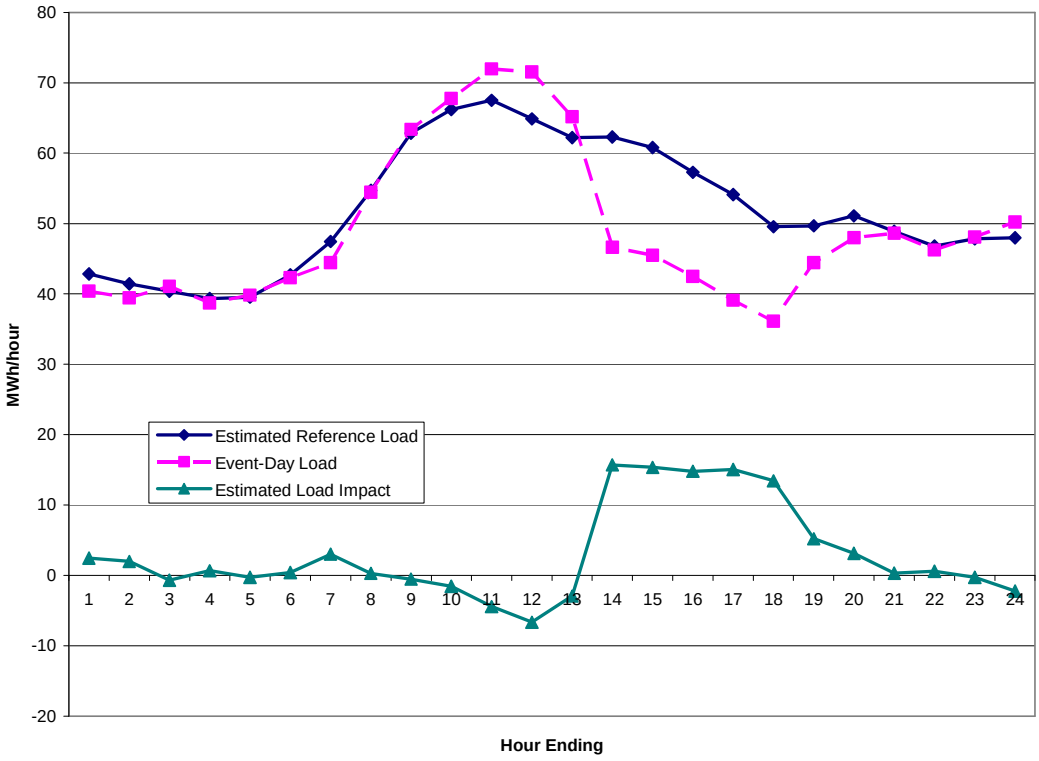


Table 5–6 reports average event-hour load impacts years for the typical event day in 1-in-2 and 1-in-10 weather years for CBP DA and DO, and DSP, for 2011 through 2014, after which the forecasts level off.

Table 5–6: Average Event-Hour Load Impacts (MW) by Forecast Year for the Typical Event Day – *SDGE CBP DA and DO, and DSP*

	CBP				DSP	
	1-in-2 Weather Yr		1-in-10 Weather Yr		1-in-2	1-in-10
Year	DA	DO	DA	DO		
2011	9.3	10.4	9.2	10.6	11.8	12.6
2012	10.2	12.5	10.1	12.8	14.9	15.7
2013	11.1	14.6	11.1	14.9	14.9	15.7
2014	11.3	16.5	11.3	16.9	14.9	15.7

5.4.4 Ex-Ante Load Impacts by Month and Program

This sub-section reports ex ante load impact forecasts by monthly peak day in a 1-2 weather year for each program and product type. In some cases, forecasts are shown for the ten years from 2011 through 2020. In others, where the forecasts remain constant after the first few years, results are only shown through 2014. In most cases, estimated load impacts are greatest in July, August and September.

Table 5–7: Average Event-Hour Load Impacts (MW) by Month and Forecast Year in a 1-in-2 Weather Year – *PG&E CBP DA*

Year	May	June	July	August	Sept.	Oct.
2011	22.6	25.2	25.1	24.7	24.8	23.7
2012	22.6	25.2	25.1	24.7	24.8	23.7
2013	22.6	25.2	25.1	24.7	24.8	23.7
2014	22.6	25.2	25.1	24.7	24.8	23.7

Table 5–8: Average Event-Hour Load Impacts (MW) by Month and Forecast Year in a 1-in-2 Weather Year – *PG&E CBP DO*

Year	May	June	July	August	Sept.	Oct.
2011	25.4	29.1	29.5	29.8	29.6	26.6
2012	25.4	29.1	29.5	29.8	29.6	26.6
2013	25.4	29.1	29.5	29.8	29.6	26.6
2014	25.4	29.1	29.5	29.8	29.6	26.6

Table 5–9: Average Event-Hour Load Impacts (MW) by Month and Forecast Year in a 1-in-2 Weather Year – *PG&E AMP DA*

Year	May	June	July	August	Sept.	Oct.
2011	40	40	40	40	40	40
2012	40	40	40	40	40	40
2013	40	40	40	40	40	40
2014	40	40	40	40	40	40

Table 5–10: Average Event-Hour Load Impacts (MW) by Month and Forecast Year in a 1-in-2 Weather Year – *PG&E AMP DO*

Year	May	June	July	August	Sept.	Oct.
2011	149	149	149	149	149	149
2012	149	149	149	149	149	149
2013	149	149	149	149	149	149
2014	149	149	149	149	149	149

Table 5–11: Average Event-Hour Load Impacts (MW) by Month and Forecast Year in a 1-in-2 Weather Year – *SCE CBP DA*

Year	May	June	July	August	Sept.	Oct.
2011	1.0	1.0	1.0	1.1	1.0	1.0
2012	1.2	1.2	1.2	1.3	1.2	1.2
2013	1.3	1.4	1.4	1.5	1.4	1.4
2014	1.5	1.6	1.6	1.7	1.6	1.5
2015	1.5	1.6	1.6	1.7	1.6	1.5
2016	1.5	1.6	1.6	1.7	1.6	1.5
2017	1.5	1.6	1.6	1.7	1.6	1.5
2018	1.5	1.6	1.6	1.7	1.6	1.5
2019	1.5	1.6	1.6	1.7	1.6	1.5
2020	1.5	1.6	1.6	1.7	1.6	1.5

Table 5–12: Average Event-Hour Load Impacts (MW) by Month and Forecast Year in a 1-in-2 Weather Year – *SCE CBP DO*

Year	May	June	July	August	Sept.	Oct.
2011	15.9	16.4	17.0	17.4	17.3	16.1
2012	17.0	17.6	18.2	18.6	18.5	17.3
2013	18.1	18.7	19.4	19.9	19.7	18.4
2014	19.2	19.9	20.6	21.1	21.0	19.6
2015	19.2	19.9	20.6	21.1	21.0	19.6
2016	19.2	19.9	20.6	21.1	21.0	19.6
2017	19.2	19.9	20.6	21.1	21.0	19.6
2018	19.2	19.9	20.6	21.1	21.0	19.6
2019	19.2	19.9	20.6	21.1	21.0	19.6
2020	19.2	19.9	20.6	21.1	21.0	19.6

Table 5–13: Average Event-Hour Load Impacts (MW) by Month and Forecast Year in a 1-in-2 Weather Year – *SCE DRC DA*

Year	May	June	July	August	Sept.	Oct.
2011	24.2	24.7	25.9	26.4	26.2	24.7
2012	23.4	23.9	25.0	25.6	25.3	23.8
2013	0.00	0.00	0.00	0.00	0.00	0.00
2014	0.00	0.00	0.00	0.00	0.00	0.00

Table 5–14: Average Event-Hour Load Impacts (MW) by Month and Forecast Year in a 1-in-2 Weather Year – *SCE DRC DO*

Year	May	June	July	August	Sept.	Oct.
2011	77.6	77.4	79.9	81.8	81.7	78.5
2012	75.5	75.3	77.7	79.6	79.5	76.4
2013	0.0	0.0	0.0	0.0	0.0	0.0
2014	0.0	0.0	0.0	0.0	0.0	0.0

Table 5–15: Average Event-Hour Load Impacts (MW) by Month and Forecast Year in a 1-in-2 Weather Year – *SDG&E CBP DA*

Year	May	June	July	August	Sept.	Oct.
2011	8.6	8.8	8.8	9.3	9.0	8.9
2012	9.2	9.5	9.7	10.2	10.1	10.0
2013	10.2	10.4	10.6	11.1	11.0	10.8
2014	10.5	10.7	10.8	11.3	11.1	10.8
2015	10.5	10.7	10.8	11.3	11.1	10.8
2016	10.5	10.7	10.8	11.3	11.1	10.8
2017	10.5	10.7	10.8	11.3	11.1	10.8
2018	10.5	10.7	10.8	11.3	11.1	10.8
2019	10.5	10.7	10.8	11.3	11.1	10.8
2020	10.5	10.7	10.8	11.3	11.1	10.8

Table 5–16: Average Event-Hour Load Impacts (MW) by Month and Forecast Year in a 1-in-2 Weather Year – *SD&E CBP DO*

Year	May	June	July	August	Sept.	Oct.
2011	9.3	9.4	10.2	10.5	11.0	10.4
2012	11.4	11.5	12.3	12.7	13.2	12.5
2013	13.3	13.4	14.4	14.7	15.2	14.3
2014	15.2	15.2	16.3	16.7	17.3	16.2
2015	15.2	15.2	16.3	16.7	17.3	16.2
2016	15.2	15.2	16.3	16.7	17.3	16.2
2017	15.2	15.2	16.3	16.7	17.3	16.2
2018	15.2	15.2	16.3	16.7	17.3	16.2
2019	15.2	15.2	16.3	16.7	17.3	16.2
2020	15.2	15.2	16.3	16.7	17.3	16.2

Table 5–17: Average Event-Hour Load Impacts (MW) by Month and Forecast Year for the Typical Event Day – *SDGE DSP*

Year	May	June	July	August	Sept.	Oct.
2011	11.6	10.4	11.7	12.0	13.9	14.4
2012	15.1	13.7	14.8	15.0	16.7	16.8
2013	15.1	13.7	14.8	15.0	16.7	16.8
2014	15.1	13.7	14.8	15.0	16.7	16.8
2015	15.1	13.7	14.8	15.0	16.7	16.8
2016	15.1	13.7	14.8	15.0	16.7	16.8
2017	15.1	13.7	14.8	15.0	16.7	16.8
2018	15.1	13.7	14.8	15.0	16.7	16.8
2019	15.1	13.7	14.8	15.0	16.7	16.8
2020	15.1	13.7	14.8	15.0	16.7	16.8

6. Validity Assessment

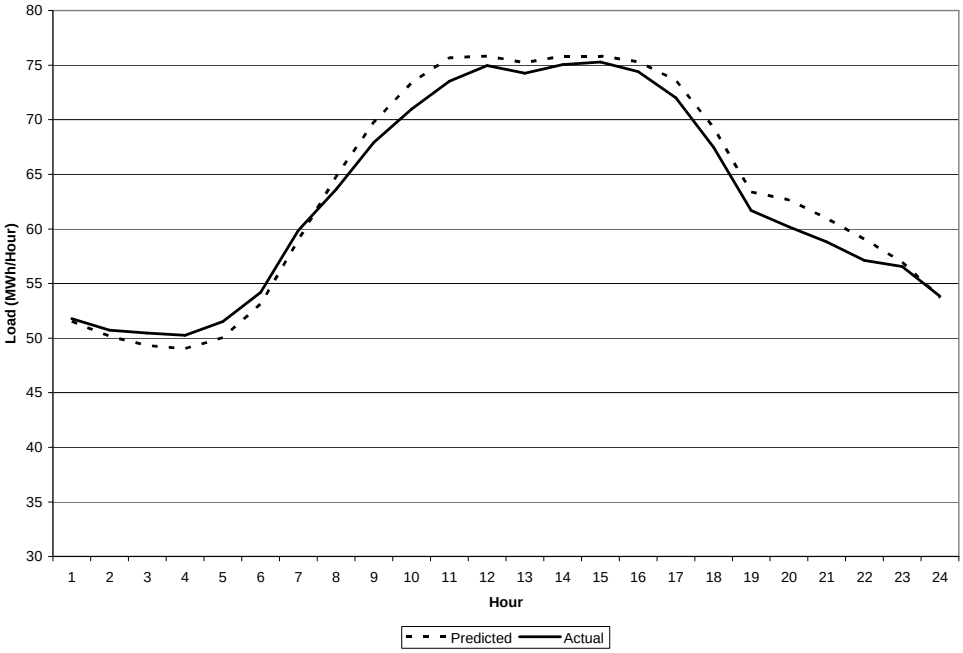
In this study, we estimated hourly event load impacts by way of estimating customer-level load-impact regression models that account for each customer's enrollment dates, and *nomination* and *called* status for each event. This method has several strong advantages (*e.g.*, properly accounting for which customer accounts are nominated to particular product types each month and called for each event; allowing the results to be summarized according to any observed customer characteristic without requiring the estimation of a new model; and the ability to screen customer-specific results for reasonableness). However, it does require the estimation of many models (*e.g.*, often for hundreds of customer accounts for each program and product type).

While we have largely automated the estimation process, the resulting number of equation results limits the extent to which each customer's regression equation can be subjected to detailed examination due to time and resource constraints. In addition, in order to facilitate efficient post-processing of the results, it is important to use a uniform model structure across all of the customers in a program. That said, we have screened the estimated equations, particularly looking for large outliers, and have rejected a few load impact estimates when the underlying raw data suggest spurious results. Fortunately, in the case of the aggregator programs, we found very few cases of unusual patterns of estimated load impacts which might suggest spurious results. In fact, most all of the largest estimated load impact coefficients were estimated with high degrees of precision (*e.g.*, t-statistics in excess of 2).

To illustrate the accuracy of the estimated load impact equations, Figures 6-1 through 6-11 present the aggregated "actual" and "predicted" hourly loads (*i.e.*, the sum across all enrolled customer accounts of the actual loads and the loads predicted by the individual customer-level regression equations) for a typical event-type day in 2010 for each of the

programs and product types.[22] In most cases, the day shown is a non-event weekday during the period of August 16 – 18. Predicted loads are shown by the dashed lines, and in most cases are reasonably close to the actual loads shown by the solid lines. There appears to be no systematic over- or under-estimation, as the prediction errors are sometimes positive and sometimes negative.

Figure 6-1: Comparison of Actual and Predicted Loads on Event-Type Day – *PG&E CBP DA*



[22] Since the numbers of customers actually nominated from month to month varies, as does the number of customers called for each event, the aggregated loads shown in these figures likely exceed the levels actually observed on particular event days.

Figure 6-2: Comparison of Actual and Predicted Loads on Event-Type Day – *PG&E CBP DO*

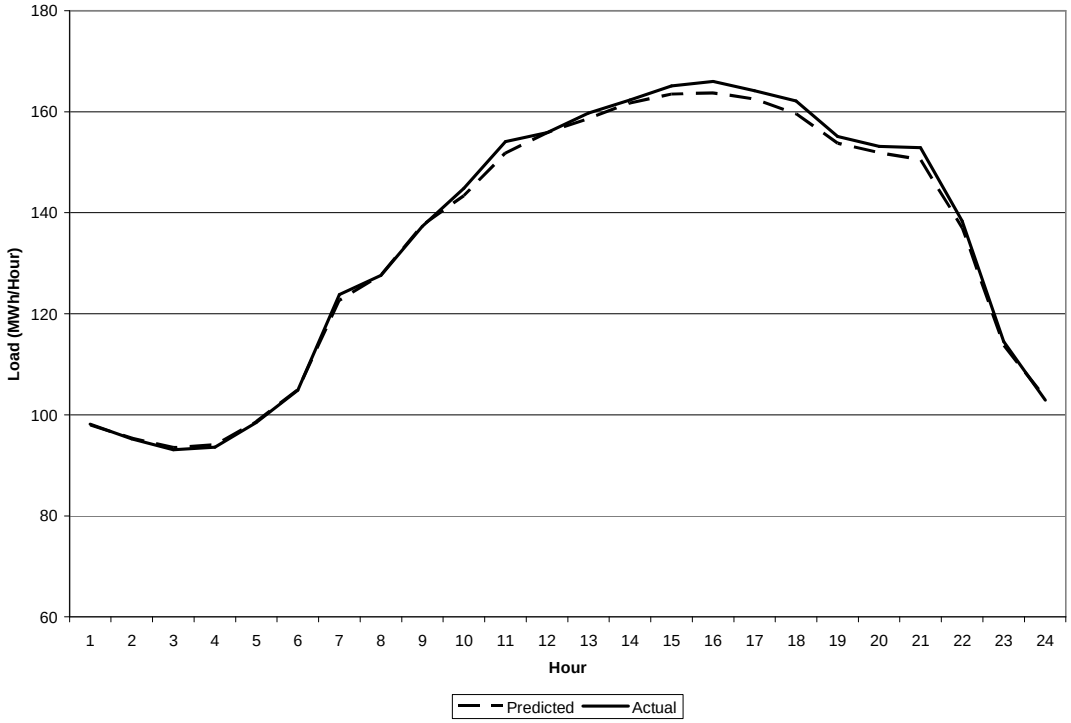


Figure 6-3: Comparison of Actual and Predicted Loads on Event-Type Day – *PG&E AMP DA*

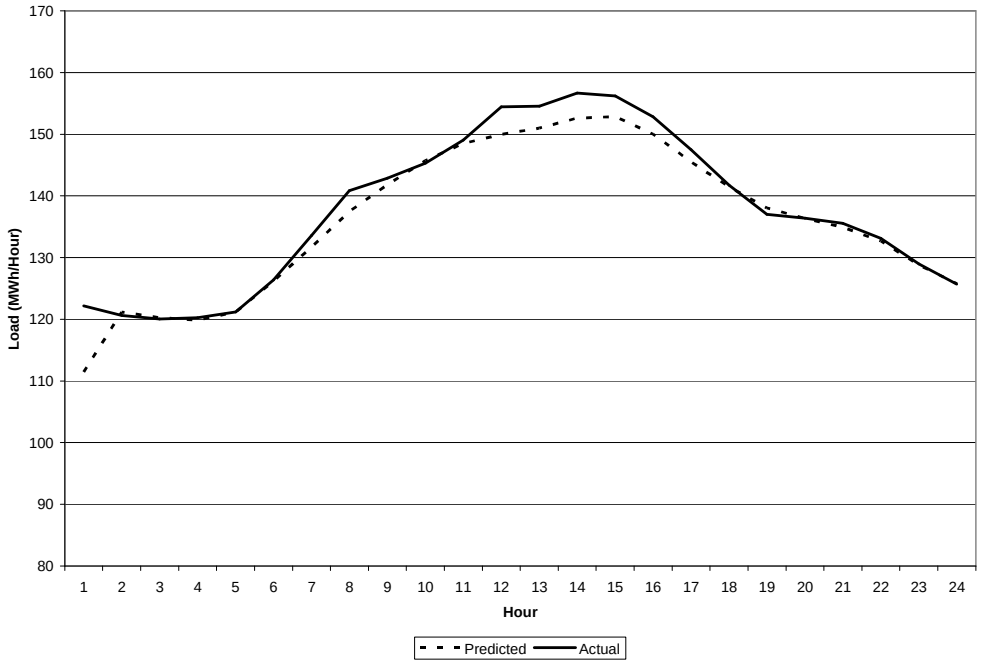


Figure 6-4: Comparison of Actual and Predicted Loads on Event-Type Day – *PG&E AMP DO*

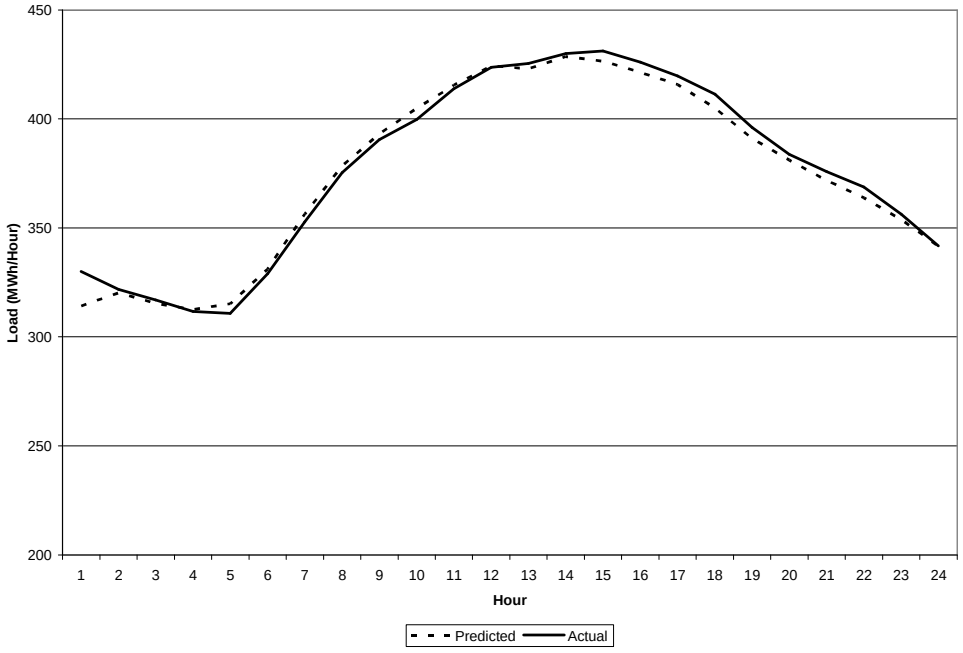


Figure 6-5: Comparison of Actual and Predicted Loads on Event-Type Day – *SCE CBP DA*

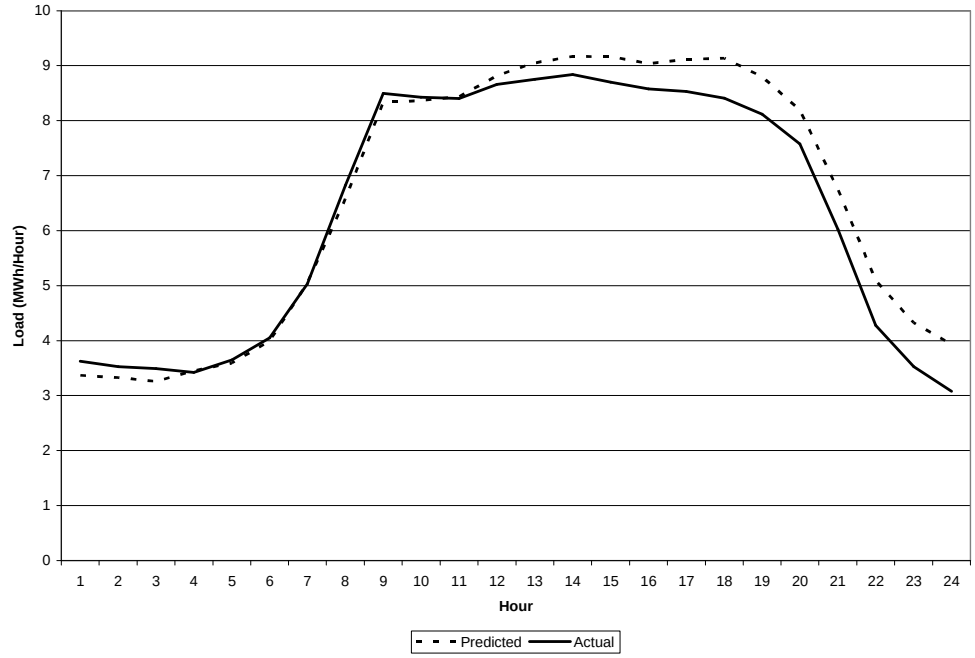


Figure 6-6: Comparison of Actual and Predicted Loads on Event-Type Day – *SCE CBP DO*

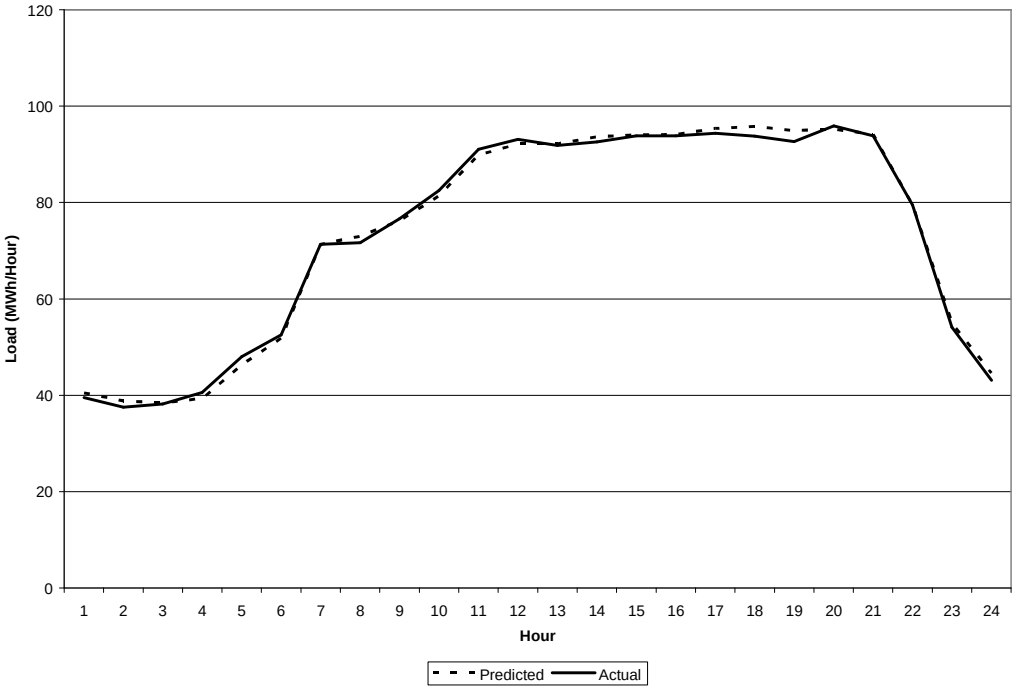


Figure 6-7: Comparison of Actual and Predicted Loads on Event-Type Day – *SCE DRC DA*

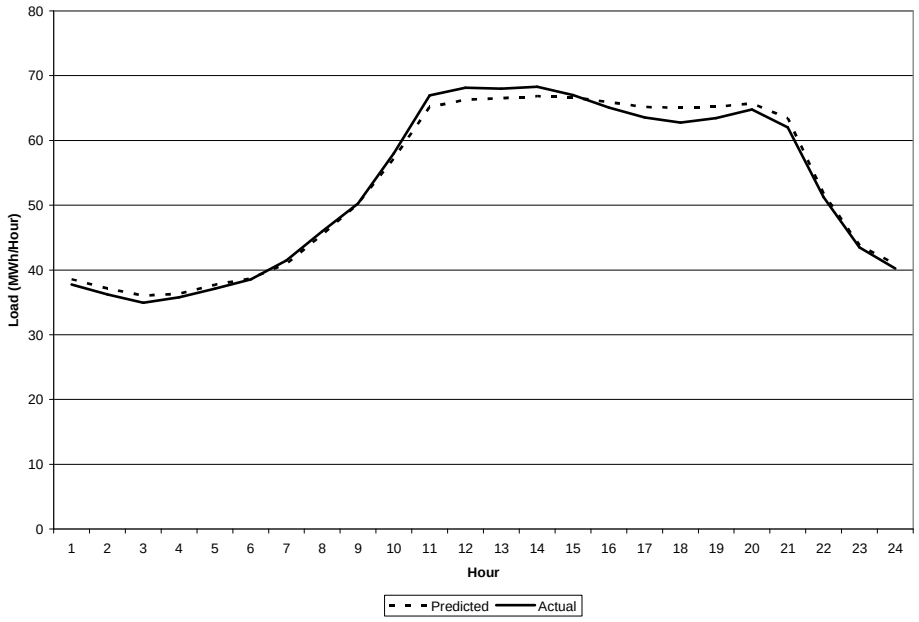


Figure 6-8: Comparison of Actual and Predicted Loads on Event-Type Day – *SCE DRC DO*

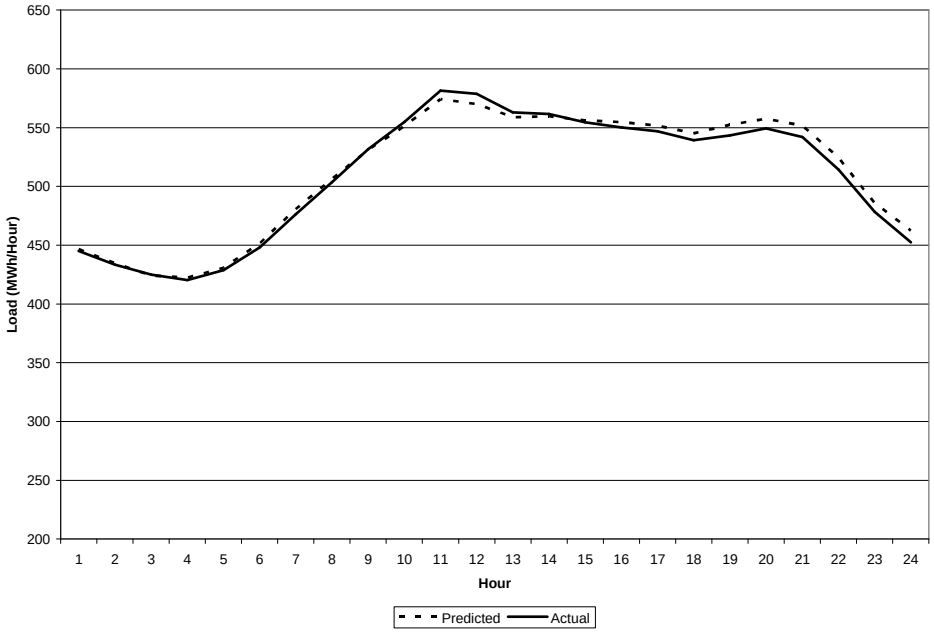


Figure 6-9: Comparison of Actual and Predicted Loads on Event-Type Day – *SDG&E CBP DA*

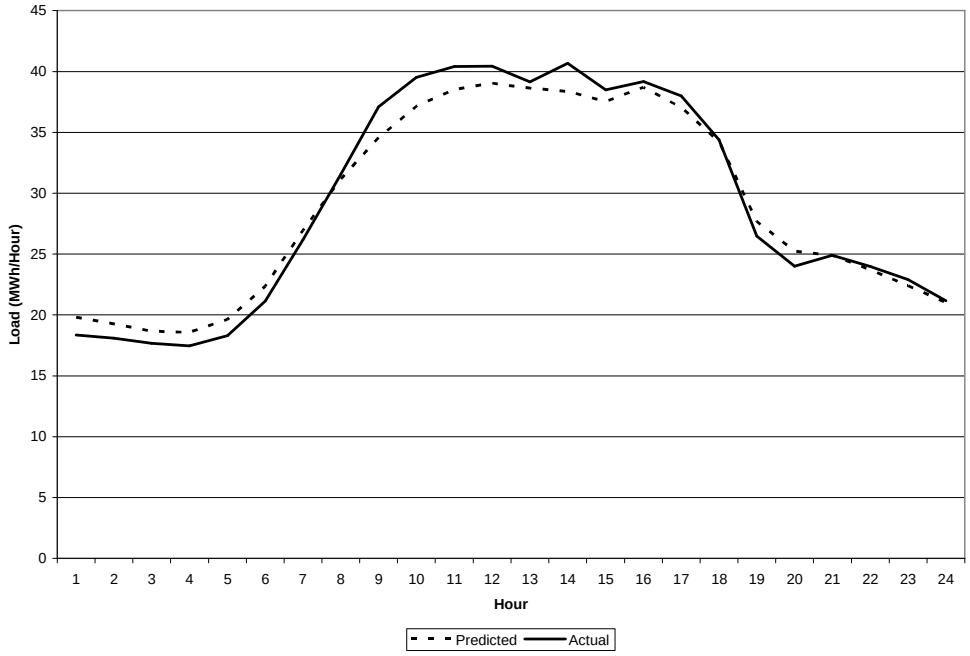


Figure 6-10: Comparison of Actual and Predicted Loads on Event-Type Day – *SDG&E CBP DO*

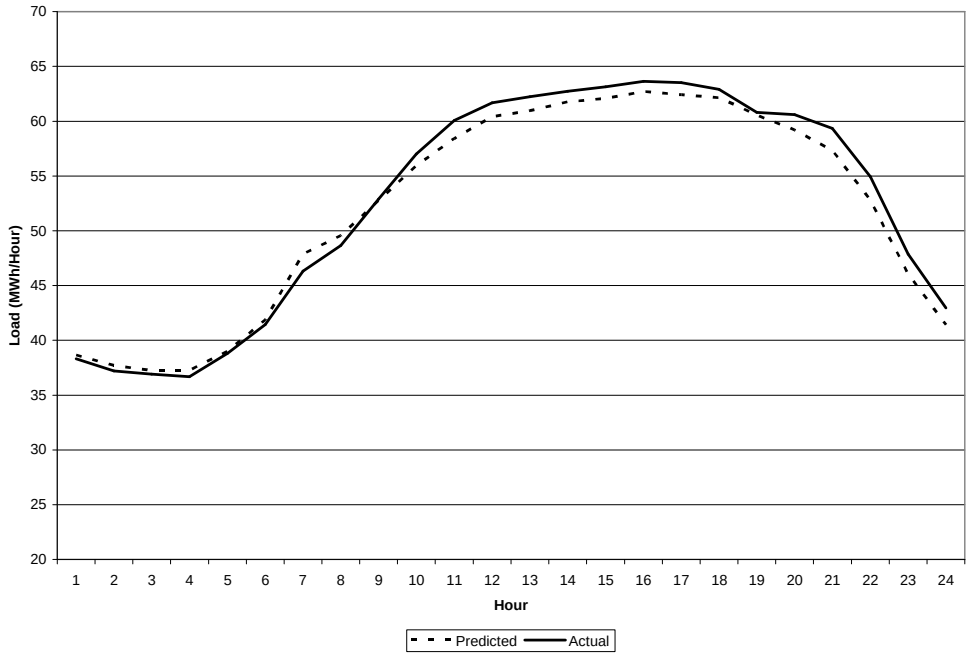
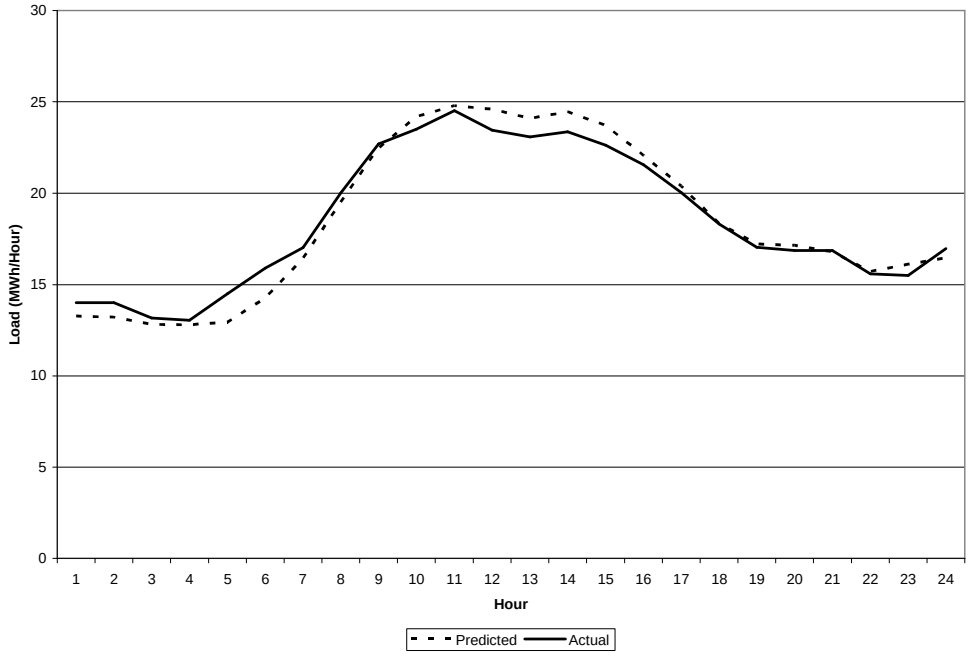


Figure 6-11: Comparison of Actual and Predicted Loads on Event-Type Day – *SDG&E DSP*



7. Recommendations

Our primary recommendation regarding evaluation of the aggregator programs follows up on last year's recommendation to work more closely with PG&E and The Brattle Group at the beginning of the enrollment forecasting process to ensure comparability of results and avoid duplication. The process seemed to work more smoothly this year, although questions still seemed to arise at the last minute regarding enrollment and nomination conventions, and enrollment trends.

Appendices

The following Appendices accompany this report. Each is an Excel file that can produce the relevant ex-post or ex-ante tables required by the Protocols.

CBP Appendices:

CBP Study Appendix A PG&E	Ex-Post Load Impact Tables
CBP Study Appendix B SCE	Ex-Post Load Impact Tables
CBP Study Appendix C SDG&E	Ex-Post Load Impact Tables
CBP Study Appendices D1 & D2 PG&E	Ex-Ante Load Impact Tables
CBP Study Appendix E SCE	Ex-Ante Load Impact Tables
CBP Study Appendix F SDG&E	Ex-Ante Load Impact Tables

Contract-Based Program Appendices:

AMP Study Appendix G PG&E	Ex-Post Load Impact Tables
AMP Study Appendices H1 & H2 PG&E	Ex-Ante Load Impact Tables

DRC Study Appendix I SCE	Ex-Post Load Impact Tables
DRC Study Appendix J SCE	Ex-Ante Load Impact Tables
DSP Study Appendix K SDG&E	Ex-Post Load Impact Tables
DSP Study Appendix L SDG&E	Ex-Ante Load Impact Tables