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2009 Load Impact Evaluation of California Statewide Critical-Peak Pricing Rates for Non-Residential Customers: Ex Post and Ex Ante Report

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Abstract

This report documents the results of a *load impact evaluation* for program-year 2009 of the California statewide critical-peak pricing (CPP) rates for non-residential customers operated by the three major investor-owned utilities (IOUs): San Diego Gas and Electric (SDG&E), Southern California Edison (SCE), and Pacific Gas and Electric (PG&E).

The primary goals of the evaluation were the following:

- To estimate the hourly ex post load impacts achieved on each event day; to determine how the load impacts on the average event day were distributed across customers in different industry types and CAISO-designated Local Capacity Areas (LCAs) (where relevant); and to estimate the incremental demand response associated with customers' participation in Technical Assistance/Technology Incentive (TA/TI) and Automated Demand Response (AutoDR) programs; and
- To provide ex ante forecasts of the load impacts expected to be achieved by CPP rates for 2010-2020 for each utility.

Prior to 2008, all of the utilities' non-residential CPP rates were voluntary, "opt-in" rates. However, beginning in May 2008, SDG&E implemented a default CPP tariff with an "opt-out" provision, and began transitioning previous volunteers onto the new default rate. SCE has proposed a default opt-out CPP rate to be implemented in late 2009, and PG&E has obtained approval for a proposed default CPP tariff, referred to as Peak Day Pricing (PDP), for large, medium, and small non-residential customers that will be established in 2010, with a transition period for customers of different sizes.

The utilities' voluntary CPP rates have similar structures, but differ in terms of customer eligibility, price levels, hours of application, number of events that may be called, and months of applicability.

Enrollment in CPP in 2009 was approximately 500 customer accounts at SCE, 650 at PG&E, and nearly 1,600 on SDG&E's default rate. Both PG&E and SCE called twelve CPP events in 2009, while SDG&E called eight events.

Methodology

The CPP ex post hourly load impacts for program-year 2009 were estimated using separate econometric models (*i.e.*, regression equations) for each enrolled CPP customer, based on historical customer load data for the summer of 2009. The models assume that customers' hourly loads are functions of weather data, time-based variables such as hour, day of week, and month, and program event information (*e.g.*, the days and hours in which events were called). The individual customer models allow the development of information on the distribution of load impacts across industry types and geographical regions, as well as the analysis of the incremental effects from automation and technology incentive programs.

Ex Post Load Impacts

Estimated ex post load impacts for program-year 2009 averaged 8.4 MW (3.3 percent of the reference load) across PG&E's twelve CPP events; 24.6 MW (18.9 percent) for SCE's twelve events; and 23.3 MW (5.6 percent) for SDG&E's eight events.
We used information on customer participation in the utilities' TA/TI and AutoDR programs to estimate the load impacts of those participants. The customers' percentage load impacts varied considerably across programs and utilities, ranging from 1 to 49 percent of their reference loads, with the SCE participants achieving the largest percentage load impacts. In addition to summarizing the *total* load impacts, we also attempted to estimate the *incremental* load impact due to AutoDR and TA/TI by comparing load impacts at the 6-digit NAICS level (or 4-digit SIC level for SCE) of participants and non-participants. However, these comparisons, which often had very small sample sizes, provided mixed results.

The methodology of estimating customer-specific regression equations and load impacts provides the capability to also examine the *distributions* of CPP load impacts across customer accounts. In general, the distributions are skewed to the left, pointing to the relatively large load impacts that are provided by only a few customers, and the correspondingly large share of total load impacts that are provided by a relatively small fraction of customer accounts. Across the three utilities, about 5 to 6 percent of customer accounts provide 61 to 72 percent of the total load impacts. At the same time, 40 to 60 percent of the customer accounts across the three utilities were estimated to have provided an average hourly load impact of at least 5 kW.

Ex Ante Load Impacts

Ex-ante CPP load impacts were prepared for 2010-2020 based on per-customer reference loads and load impact estimates from the ex post evaluation, and enrollment forecasts provided by the utilities (PG&E's forecasts were provided through a separate contract with The Brattle Group). The ex ante load impact forecasts cover an important transition period from *voluntary* non-residential CPP to *default* CPP (including PG&E's re-named PDP rate), which will extend to customer accounts below 200 kW. As a result, enrollment forecasts and projected program load impacts ramp up substantially over the next few years. Forecasts were developed and reported at the program level and by CAISO *Local Capacity Area*, as well as by certain weather and event day-type scenarios.

Representative values of enrollment and average hourly CPP/PDP program load impacts in 2013 for a typical event day in a 1-in-2 weather year, at which time the utilities' enrollment forecasts begin to level off, are 289 MW for PG&E, 40 MW for SCE, and 57 MW for SDG&E (24 MW of which is provided by customers on CPP in the 2009 program year).

Executive Summary

This report documents a load impact evaluation for program-year 2009 of the California statewide voluntary critical-peak pricing ("CPP") rates for non-residential customers offered by the three major investor-owned utilities (IOUs), Pacific Gas and Electric ("PG&E"), Southern California Edison ("SCE"), and San Diego Gas and Electric ("SDG&E"). Non-residential customers enrolling in voluntary CPP receive a discount from the otherwise applicable rates, in return for paying a higher "critical peak" price (*e.g.*, $0.30 to $1.80 per kWh) for energy used in certain peak hours on a limited number of critical-peak pricing "event" days. Customers enrolled in CPP are notified one day before a CPP event is called.

The primary goals of the evaluation were the following:

- To estimate the hourly ex post load impacts achieved on each event day; to determine how the load impacts on the average event day were distributed across customers in different industry types and CAISO-designated Local Capacity Areas (LCAs)[1] (where relevant); and to estimate the incremental demand response associated with customers' participation in Technical Assistance/Technology Incentive (TA/TI) and Automated Demand Response (AutoDR) programs; and
- To provide ex ante forecasts of the load impacts expected to be achieved by CPP rates for 2010-2020 for each utility.

ES 1 Resources Covered

ES1.1 CPP tariffs

Prior to 2008, all of the utilities' non-residential CPP rates were voluntary, "opt-in" rates. However, beginning in May 2008, SDG&E implemented a default CPP tariff with an "opt-out" provision, and began transitioning previous volunteers onto the new default rate. SCE has proposed a default opt-out CPP rate to be implemented in late 2009, and PG&E has obtained approval for a proposed default CPP tariff, referred to as Peak Day Pricing (PDP), for large, medium, and small non-residential customers that will be established in 2010, with a transition period for customers of different sizes.

The utilities' voluntary CPP rates have similar structures, but differ in terms of customer eligibility,[2] price levels, hours of application, number of events that may be called, and months of applicability. PG&E's CPP rates are tied to customers' otherwise applicable tariff (OAT), and thus take on different values for different rate classes (*e.g.*, the CPP rates provide *credits* relative to the OAT rates during non-CPP on-peak and part-peak hours, and additional *charges* during event hours on CPP days). Their rates have a *moderate* CPP price for the first three hours and a *high* CPP price for the last three hours of the six-hour CPP event period.

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[1] Local Capacity Area (or LCA) refers to CAISO-designated load pocket or transmission constrained geographic areas for utilities are required to meet local capacity requirements. PG&E has seven LCAs in its service area, SCE has three, and SDG&E's is considered to be one LCA.

[2] For example, only non-residential customers with maximum demands of over 200 kW are eligible to enroll in PG&E's voluntary CPP program.

SDG&E's default CPP also takes on different values for different rate classes. The default CPP rate is a commodity-only rate and customers pay all non-commodity charges according to their otherwise applicable tariff. Customers on SDG&E's default CPP are allowed to pay a monthly capacity reservation charge (CRC) that limits the amount of their load that is exposed to CPP prices on event days. In addition, customers receive a bill guarantee for one year, during which their bill under default CPP is guaranteed not to exceed what it would have been had they opted out to the new OAT.[3]

SCE offers two voluntary CPP tariffs. One, CPP – Volumetric Charge Discount ("CPP-VCD"), is of similar structure to PG&E's rates. The other, CPP – Generation Capacity Charge Discount ("CPP-GCCD"), is aimed at large (> 500 kW) customers, and involves a single high CPP price for the entire six-hour critical period on event days in return for a discounted summer on-peak demand charge.

ES 1.2 Enrollment

CPP enrollment by industry type, in terms of numbers of customer accounts and percent of load, for each of the utilities is summarized in Table ES.1. Differences in the enrollment shares by industry type are illustrated in pie charts below.

Table ES.1: CPP Enrollment – Customer Accounts and Share of Load, by Utility

	Number of SAIDs			% of Max kW		
Industry Type	PG&E	SCE	SDG&E	PG&E	SCE	SDG&E
1. Agriculture, Mining & Construction	39	24	19	6%	4%	2%
2. Manufacturing	167	221	222	34%	49%	15%
3. Wholesale, Transport, other Utilities	67	54	266	8%	18%	20%
4. Retail stores	42	35	128	3%	7%	7%
5. Offices, Hotels, Health, Services	127	44	481	25%	7%	36%
6. Schools	159	99	267	14%	13%	9%
7. Gov't, Entertainment, Other Services	49	8	190	9%	1%	11%
8. Other/Unknown			7			0%
TOTAL	650	485	1,580	100%	100%	100%

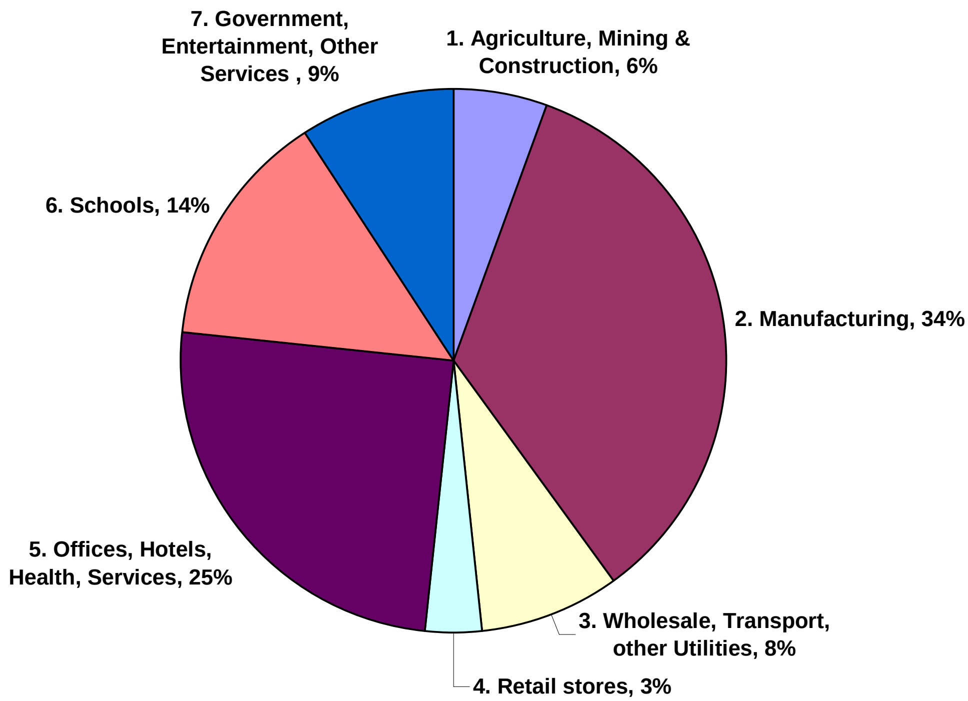
Enrollment in CPP at PG&E in 2009 fell to 650 customer service accounts, from 760 accounts in 2008, after expanding from 337 accounts in 2006 and 656 accounts in 2007.[4] The total load of the customer accounts enrolled in CPP, measured as the sum of individual customers' maximum demands, amounted to nearly 400 MW.[5] The Manufacturing; Offices, Hotels, Finance and Services; and Schools industry groups made up the bulk of PG&E's CPP enrollment, measured by the share of maximum demand, as illustrated in Figure ES.1.

[3] Note that SDG&E no longer offers its voluntary CPP rates; all previous participants have been transitioned to the new default CPP rate.

[4] The number of accounts enrolled in PG&E's program is defined as the number of service agreement identification numbers (SA_IDs) that are listed as "enrolled" in PG&E's database. Frequently a single customer will have more than one SA_ID – such as for multiple facilities at different locations.

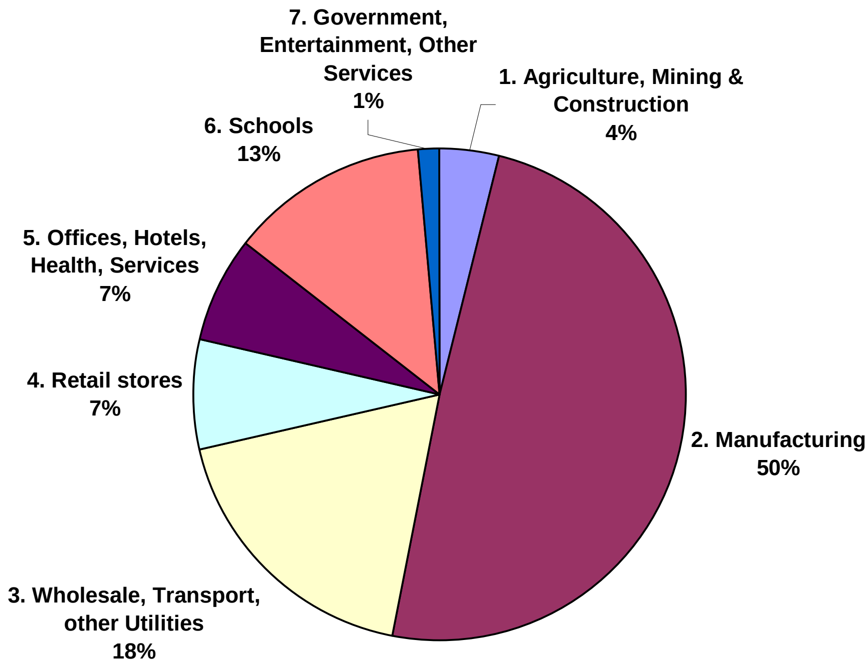
[5] Maximum demand represents a convenient metric for characterizing program enrollment. However, the hourly CPP load impacts that are reported in the text are calculated relative to a *reference load* that represents an estimate of what customers' usage would have been on a comparable non-event day.

Figure ES.1 Share of CPP Enrolled Load (Maximum Demand) by Industry Type – *PG&E*



SCE's enrollment in CPP has continued to expand, from just 15 customer accounts in 2006, to 44 accounts in 2007, 201 accounts in 2008, and 485 in 2009. Total maximum demand of customers enrolled in 2009 nearly doubled to approximately 283 MW. Manufacturing and Wholesale, Transportation and Other Utilities industry groups made up the bulk of CPP participating load at SCE. Figure ES.2 shows the complete distributions of enrollment across industry-types.

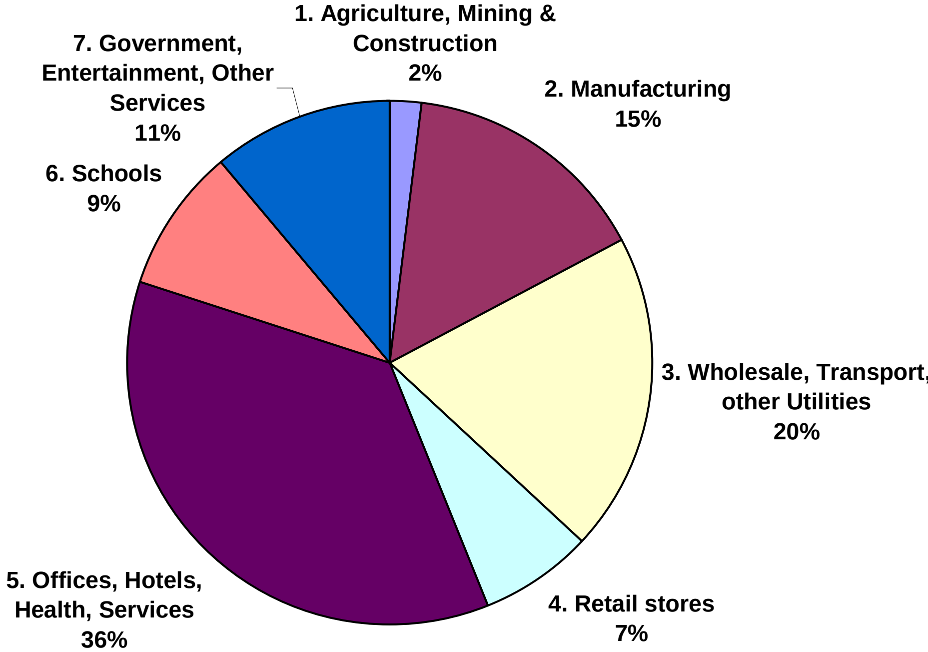
Figure ES.2 Share of CPP Enrolled Load (Maximum Demand) by Industry Type – *SCE*



Nearly 1,600 customer accounts participated in default CPP at SDG&E in 2009, declining to opt out to the new otherwise applicable time-of-use rate after being defaulted onto the new CPP rate in 2008.[6] Approximately 1,800 customers were defaulted onto the new CPP rate in 2008. Approximately three-quarters of those customers remained on the rate in the first year. However, no CPP events were called in 2008. In 2007, the last year of the voluntary CPP rate, enrollment nearly doubled compared to 2006, from 120 to 233 enrollees, representing 200 MW of maximum demand. Figure ES.3 shows the distribution of SDG&E's 611 MW of CPP load across industry types in 2009. Offices, Hotels, Finance and Services, and Wholesale, Transportation and Other Utilities industry groups accounted for more than half of the total load.

[6] Customers of size greater than 20 kW were eligible for the new CPP rate if they met the interval data recorder metering requirement and had been on a demand response program previously. Otherwise, only customers of size greater than 200 kW were assigned to the default CPP rate.

Figure ES.3 Share of CPP Enrolled Load (Maximum Demand) by Industry Type – *SDG&E*



ES 1.3 CPP events

Table ES.2 lists CPP event days for each of the utilities in 2009. PG&E and SCE each called 12 CPP events (PG&E's first event was a test event), while SDG&E called 8 events. The utilities often called events on different days, though there was some overlap, particularly in the last week of August. PG&E's events started earliest in the summer, and ended earliest in the season, while SDG&E's events did not begin until late August and extended into late September.

Table ES.2: CPP Events – 2009

Date	PG&E	SCE	SDG&E
6/18		1 (Test)	
6/29	1		
6/30	2		
7/13	3		
7/14	4		
7/15		2	
7/16	5		
7/17		3	
7/20		4	
7/21	6		
7/22		5	
7/27	7	6	
7/28		7	
8/10	8		
8/11	9		
8/18	10		
8/20		8	
8/27	11	9	1
8/28	12	10	2
8/29			3*
8/31			4
9/1		11	
9/2		12	
9/3			5
9/4			6
9/24			7
9/25			8

* Saturday

ES 2 Evaluation Methodology

The CPP ex post hourly load impacts for program-year 2009 were estimated using separate econometric models (*i.e.*, regression equations) for each enrolled CPP customer, based on historical customer load data for the summer of 2009. The models assume that customers' hourly loads are functions of weather data, time-based variables such as hour, day of week, and month, and program event information (*e.g.*, the days and hours in which events were called). The individual customer models allow the development of information on the distribution of load impacts across industry types and geographical regions, as well as the analysis of the incremental effects from automation and technology incentive programs.

ES 3 Ex Post Load Impact Evaluation

ES 3.1 Load impact summary

Load impacts were estimated for each hour of each CPP event at PG&E, SCE, and SDG&E in the ex post load impact evaluation. Table ES.3 summarizes the number of participating customer accounts, the average event-hour estimated reference and observed loads, and estimated load impacts for the average CPP event at each of the three utilities.[7] Also shown are load impacts as a percent of the estimated reference loads, and average event-hour load impacts per customer, which were 13, 52, and 15 kW for PG&E, SCE and SDG&E respectively. Overall program-level estimated load impacts for program-year 2009 averaged 8.4 MW (3.3 percent of the reference load) across PG&E's twelve CPP events; 24.6 MW (18.9 percent) for SCE's twelve events; and 23.3 MW (5.6 percent) for SDG&E's eight events.

Table ES.3: Average Hourly CPP Loads and Load Impacts, by Utility
Average Event

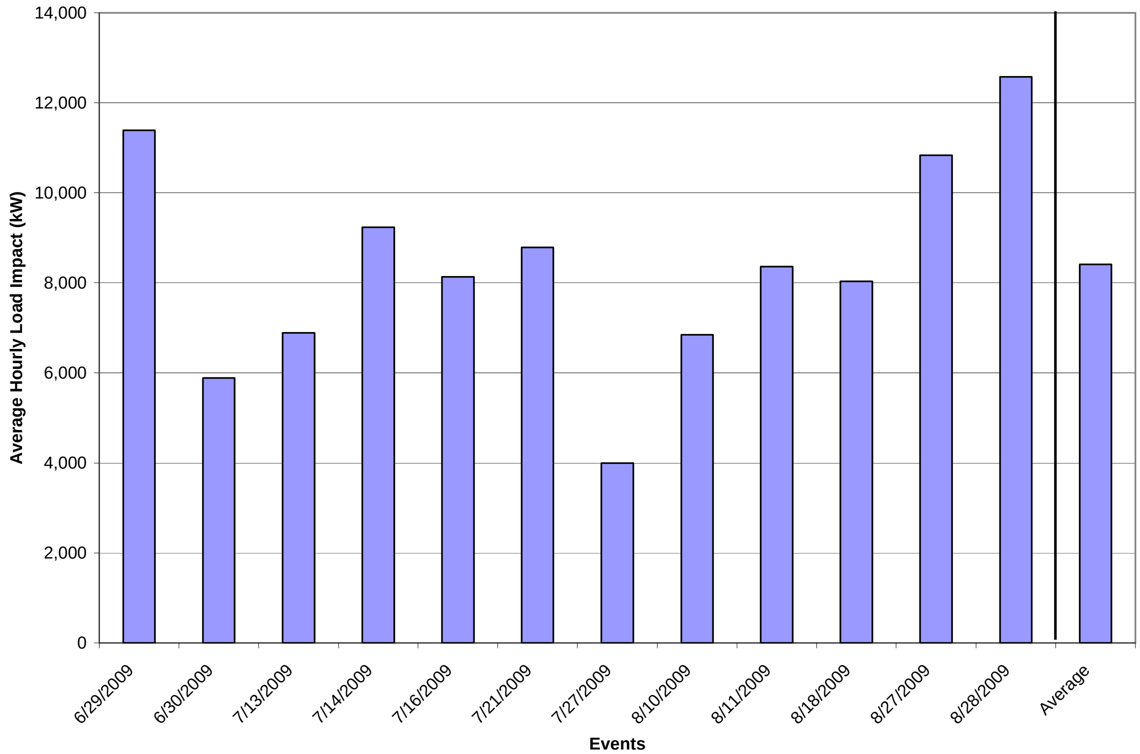
Utility	Customer Accounts	Estimated Reference Load (MW)	Observed Load (MW)	Estimated Load Impact (MW)	% Load Impact	Estimated Load Impact per Customer (kW)
PG&E	642	256	247	8.4	3.3%	13
SCE	476	130	106	24.6	18.9%	52
SDG&E	1,576	419	396	23.3	5.6%	15

Figure ES.4 illustrates the variability of load impacts across events for PG&E by reporting average hourly load impacts during the six-hour event period *for each* of PG&E's twelve CPP event days, as well as the average load impact across events. The mean value across events of the average hourly load impacts was 8.4 MW, and load impacts ranged from 4.0 to 12.6 MW, with a standard deviation of 2.4 MW. These values represent percentage load impacts that range from about 1.7 percent to 4.5 percent of the reference load, which averaged 256 MW across the event period.[8] The Manufacturing; Retail; and Offices, Hotels, Finance and Services industry types provided the largest load impacts, while Retail stores provided the largest *percentage* load impacts.

[7] Note that the number of enrolled customer accounts in Table ES.3 do not match the enrollments in Table ES.1 exactly. Table ES.1 summarizes the characteristics of customers who were enrolled at the time of *any* event day in 2009, while Table ES.3 shows the average across event days of the number of customers enrolled at the time of each event.

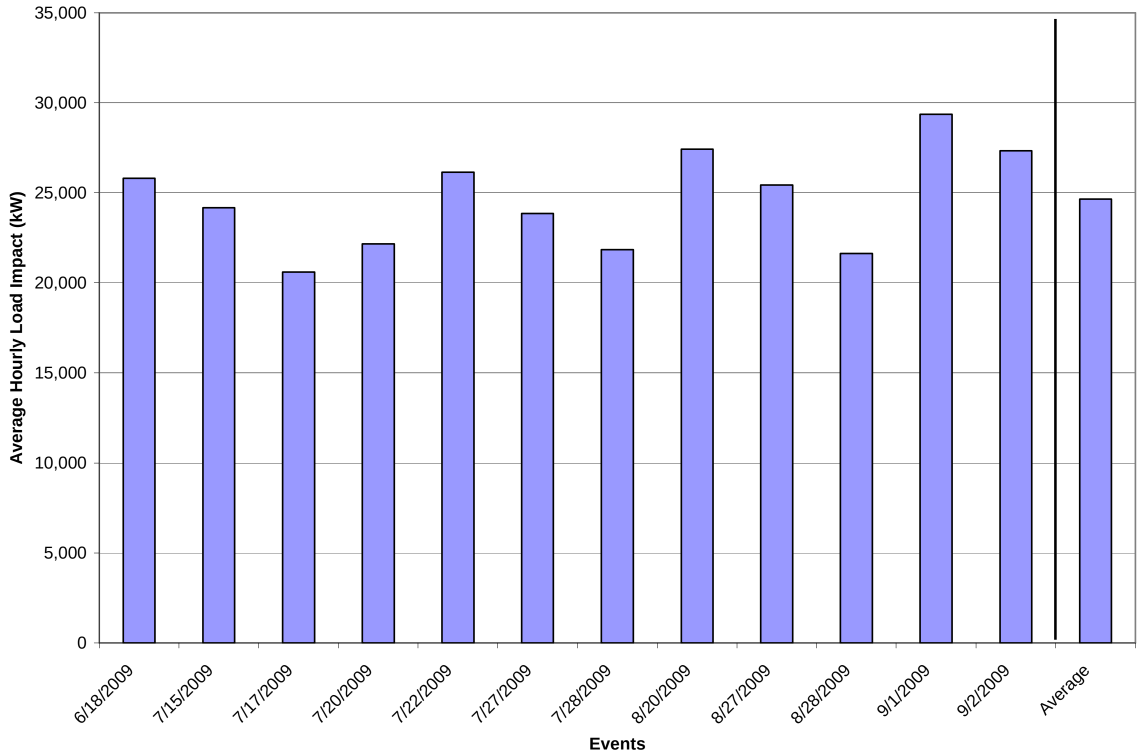
[8] The reference load is our estimate of what the CPP customers' load would have been if the event had not been called, and is based on observed data and the estimated load impacts.

Figure ES.4 Average Hourly CPP Load Impacts by Event – *PG&E*



The average estimated hourly load impacts across SCE's twelve CPP event days in 2009, shown in Figure ES.5, were quite consistent, with an average hourly load reduction of nearly 25 MW, or about 19 percent of the estimated reference load. Manufacturing customers accounted for the bulk of the load impacts.

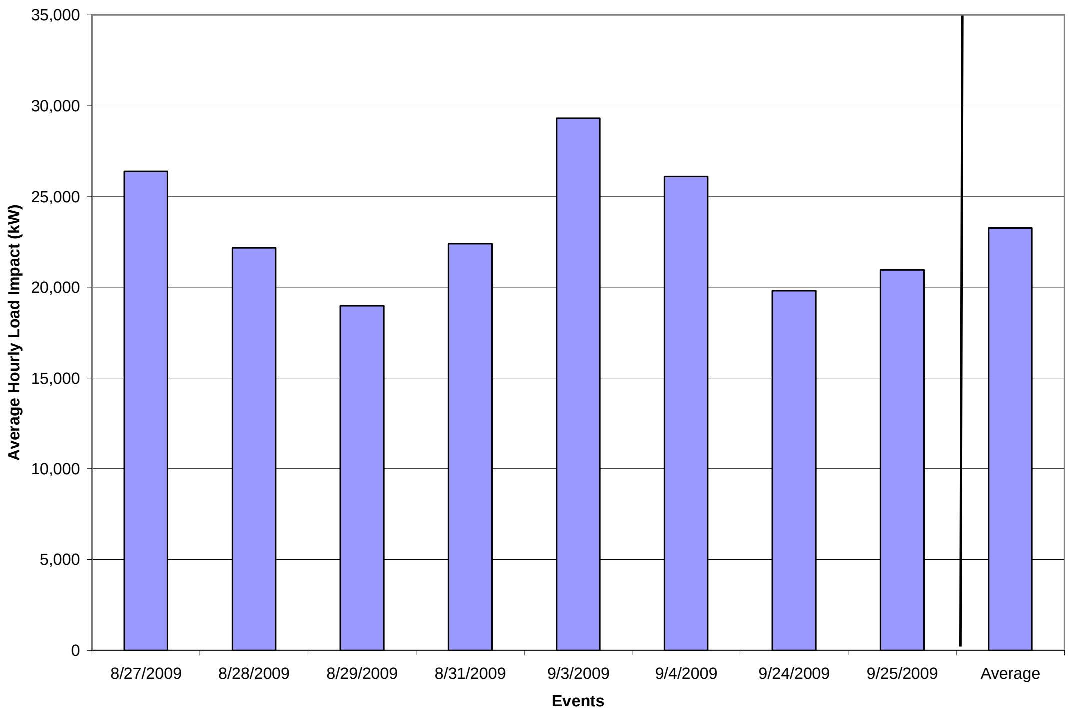
Figure ES.5 Average Hourly CPP Load Impacts by Event – *SCE*



The average hourly CPP load impacts at SDG&E were also reasonably consistent across the eight events called in 2009, as shown in Figure ES.6 below.[9] Load impacts ranged from 19.8 MW to 29.3 MW across weekday events, with a Saturday event on August 29 producing 19 MW. Load impacts averaged 23.3 MW, or about 5.6 percent of the CPP reference load. The load impacts were somewhat smaller than average for the Saturday event and the two late-September events. The largest load impacts were provided by the Offices, Hotels, Health and Services, and Wholesale, Transportation and Utilities (largely water utilities) industry groups. Load impacts were greatest (29.3 MW) on September 3, which appears to be the SDG&E system peak day, as well as the peak day for the state.

[9] It should be noted that SDG&E allows joint participation in CPP and the Capacity Bidding Program (CBP) day-of (DO) program type. If CPP and CBP-DO events are called on the same day, customer accounts that are enrolled in both programs continue to face CPP prices on that day, and do not receive energy credits for CBP load reductions. However, the CPUC has ruled that for resource adequacy purposes, capacity-based program load impacts receive a higher priority than those of energy-based programs. Contemporaneous CPP and CBP-DO events were called three times in 2009, on August 27, August 28, and September 3. We estimate that those customer accounts that were enrolled in both programs provided approximately 4 MW of average hourly load impacts. Thus, from a resource adequacy perspective, the estimated CPP load impacts on those three days should be reduced by approximately 4 MW.

Figure ES.6 Average Hourly CPP Load Impacts by Event – *SDG&E*



ES 3.2 AutoDR and TA/TI effects

Ex post load impacts were estimated for 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 so that they can identify ways to participate in DR. The TI portion of the program then provides incentive payments for the installation of equipment or control software supporting DR.

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

Table ES.4 shows the total load impacts achieved by both TA/TI and AutoDR participants, for each utility. The customers' percentage load impacts vary considerably across programs, ranging from 2 to 49 percent of their reference loads.

In addition to summarizing the *total* load impacts provided by participating service accounts, we also attempted to estimate the *incremental* load impact due to AutoDR and TA/TI by comparing load impacts at the 6-digit NAICS level (or 4-digit SIC level for SCE). These comparisons provided mixed results.

Table ES.4: Average Hourly Load Impacts Achieved by AutoDR and TA/TI Customer Accounts, by Utility

Utility	Program	# SAIDs	Average Load Impact (kW)	Percentage Load Impact
PG&E	AutoDR	34	1,598	6.0%
	TATI	7	149	2.3%
SCE	AutoDR	17	1,878	28.0%
	TATI	1	476	49.0%
SDG&E	AutoDR	12	1,371	17.2%
	TATI	13	714	13.4%

ES 3.3 Distributions of CPP load impacts

The methodology of estimating customer-specific regression equations and load impacts in this evaluation also provides the capability to examine the *distributions* of CPP load impacts across customer accounts. Table ES.5 summarizes some of the key indicators of these distributions across the utilities. In general, the three distributions have quite similar characteristics. They are generally skewed to the left, pointing to the relatively large load impacts provided by only a few customers, and to the correspondingly large share of total load impacts that are provided by a relatively small fraction of customer accounts. The first column in the table reports the percentage of customers who were estimated to provide load impacts of at least 5 kW. The 59 percent value for SCE (compared to 35 and 40 percent for SDG&E and PG&E) is consistent with the findings of greater price responsiveness among SCE's CPP customers.[10] The second and third columns are related. The second column shows the cumulative percentages of customer accounts that provided the share of total program load impacts shown in the third column. As shown in the table, from 4.6 to 6.5 percent of the customers provide 61 to 72 percent of the total program load impacts across the three utilities.

Table ES.5: Indicators of CPP Customer Price-Responsiveness

Utility	Percent of Customers with Estimated LI > 5 kW	Cumulative % of Customers that Provide…	the Following % of Total Load Impacts
PG&E	40%	5.0%	64%
SCE	59%	6.5%	61%
SDG&E	35%	4.6%	72%

ES 4 Ex Ante Load Impact Evaluation

Ex-ante load impacts were prepared for CPP for 2010-2020 based on reference loads and load impact estimates from the ex post evaluation, and enrollment forecasts provided by the utilities, where PG&E's forecasts were provided through a separate contract with The

[10] Note that most of SCE's voluntary CPP customers selected the rate option that has the highest CPP price (in return for a discounted summer peak demand charge), and have historically included large and flexible manufacturing and water utility customers who have the ability and financial incentive to reduce load during CPP event hours.

Brattle Group. The ex ante load impact forecasts cover an important transition period from voluntary non-residential CPP to default CPP (including PG&E's re-named Peak Day Pricing (PDP) program), which will extend to customer accounts below 200 kW. As a result, enrollment forecasts and projected program load impacts ramp up substantially over the next few years. Forecasts are developed and reported at the program level and by CAISO *Local Capacity Area*, as well as by certain weather and event day-type scenarios.

Representative values of enrollment and average hourly CPP/PDP program load impacts in 2013 for a typical event day in a 1-in-2 weather year, at which time the utilities' enrollment forecasts begin to level off, are shown in Table ES.6. Forecast load impacts are 289 MW for PG&E, 40 MW for SCE, and 57 MW for SDG&E (24 MW of which was on CPP in the 2009 program year).

Table ES.6: Ex Ante Load Impacts Forecasts – 2013 in 1-in-2 Weather Year

Utility	Count	Estimated Load Impact (MW)
PG&E	264,274	289
SCE	2,428	40
SDG&E – Current	1,524	24
SDG&E - New	13,271	33

ES 5 Summary

Estimated ex post load impacts for program-year 2009 averaged 8.4 MW (3.3 percent of the reference load) across PG&E's twelve CPP events; 24.6 MW (18.9 percent) for SCE's twelve events; and 23.3 MW (5.6 percent) for SDG&E's eight events. Load impacts as the utilities transition to default CPP/PDP are expected to grow substantially.

1. Introduction and Purpose of the Study

This report documents a load impact evaluation for program-year 2009 of the California statewide voluntary critical-peak pricing ("CPP") rates for non-residential customers offered by the three major investor-owned utilities (IOUs), Pacific Gas and Electric ("PG&E"), Southern California Edison ("SCE"), and San Diego Gas and Electric ("SDG&E").[11] Customers enrolling in voluntary CPP receive a discount from the otherwise applicable rates, in return for paying a higher "critical peak" price (*e.g.*, $0.30 to $1.80 per kWh) for energy used in certain hours on a limited number of critical peak pricing "event" days. Customers enrolled in CPP are notified one day before a CPP event is called.

The primary goals of the evaluation were the following:

- To estimate the hourly ex post load impacts achieved on each event day, to determine how the load impacts on the average event day were distributed across customers in different industry types and California ISO ("CAISO") local capacity areas (LCA), where relevant, and to estimate the incremental demand response associated with customers' participation in TA/TI and AutoDR incentive programs;
- To provide ex ante forecasts of the demand response expected to be achieved by CPP rates for 2010-2020 for each utility.

The load impacts for the programs were estimated using separate econometric models (*i.e.*, regression equations) for each enrolled CPP customer, based on historical load data for the summer of 2009. The models assume that hourly loads are a function of weather data; time-based variables such as hour, day of week, and month; and program event information. The individual customer models allow the development of information on the distribution of load impacts across industry types and geographical regions, and analysis of incremental effects from automation and technology incentive programs.

After this introductory section, Section 2 describes the CPP rates, including the characteristics of the enrolled customer accounts. Section 3 discusses evaluation methodology. Section 4 presents ex post CPP load impacts. Section 5 presents the ex ante load impacts. Section 6 discusses validity assessment, and Section 7 offers recommendations.

2. Description of resources covered in the study

This section provides detail on the CPP rates, including the nature of the CPP prices, the characteristics of the participants enrolled in the programs, and the events called in 2009 (each utility's CPP rates are collectively referred to as that utility's "CPP program").

2.1 CPP rates

This section describes the CPP rates offered by the three utilities in 2009. Prior to 2008, all of the utilities' CPP rates were voluntary, "opt-in" rates. However, beginning in May

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[11] Previous evaluations of these CPP programs are listed in the References section.

2008, SDG&E implemented a default CPP tariff with an "opt-out" provision, and began transitioning previous volunteers onto the new default rate. SCE has proposed a default opt-out CPP rate to be implemented in late 2009, and PG&E has proposed a default CPP tariff referred to as Peak Day Pricing that will be phased in for large C&I customers in 2010, and for large Agricultural and medium and small C&I customers in 2011, after each customer has had an interval meter for 12 months.

The utilities' voluntary CPP rates have similar structures, but differ in terms of price levels, customer eligibility, hours of application, number of events that may be called, and months of applicability. PG&E's CPP rate is tied to customers' otherwise applicable tariff (OAT). It provides *credits* relative to the OAT during non-CPP on-peak and part-peak hours, and *charges* in addition to the OAT during event hours on CPP days), and thus takes on different values for different rate classes. The rate has a moderate price for the first three hours and a higher price for the last three hours of the six-hour event period.

SDG&E's default CPP also takes on different values for different rate classes. The default CPP rate is a commodity only rate and customers pay all non-commodity charges according to their otherwise applicable tariff. Customers on SDG&E's default CPP are allowed to pay a monthly capacity reservation charge that limits their exposure to CPP on event days.

SCE offers two CPP tariffs. One, CPP – Volumetric Charge Discount ("CPP-VCD"), has three-hour moderate and three-hour high CPP prices on event days, and discounts on non-event days. The other, CPP – Generation Capacity Charge Discount ("CPP-GCCD"), is aimed at large (> 500 kW) customers, and involves a single high CPP price for the entire six-hour critical period on event days in return for a discounted summer on-peak demand charge. The majority of the SCE CPP load is on the latter CPP option.

As noted above, SDG&E implemented a default CPP tariff ("CPP-D") in 2008, which will become the default rate for non-residential bundled customers with maximum demand of 200 kW or greater. It has an opt-out provision that allows customers to return to a TOU rate, and also offers a Capacity Reservation Charge ("CRC") option that allows customers to "reserve" a specific amount of energy that is not subject to CPP prices by paying a monthly demand charge for the selected capacity amount. SDG&E also offers an optional CPP – Emergency ("CPP-E") tariff, in which CPP events may be called on 30 minutes advance notice, and a voluntary CPP rate ("CPP-V"), of similar design to the other utilities, but which is now closed to new enrollment.

2.2 Participant characteristics

In order to assess differences in load impacts across customer types, the program participants were categorized according to eight industry types. The industry groups are defined as follows (with the applicable two-digit NAICS codes):[12]

---

[12] 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.

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 or unknown

In addition, each utility provided information regarding the CAISO local capacity area (LCA) in which each customer is located.[13]

The following sets of tables summarize the characteristics of the participating customer accounts, including industry type, size, and LCA. Table 2.1 shows CPP enrollment by industry group for PG&E. Enrollment in PG&E's current CPP program for large non-residential customers declined after expanding in the previous years, with 650 customer service accounts[14] enrolled during at least one 2009 event day. Enrollments in previous years were 337 accounts in 2006, 656 accounts in 2007, and 760 accounts in 2008. Total CPP load, represented by the sum of enrolled customers' individual maximum demands[15], amounted to 395 MW. Average hourly usage for enrolled customers was 206 MW.[16] The Manufacturing; Offices, Hotels, Health care and Services; and Schools industry groups made up the bulk of PG&E's CPP enrollment.

Table 2.1: CPP Enrollees by Industry group – *PG&E (2009)*

Industry Type	Number of SAIDs	Sum of Max kW	Sum of Avg. kWh	% of Max kW	Avg. Size (kW)
1. Agriculture, Mining & Construction	39	21,945	6,217	6%	563
2. Manufacturing	167	136,032	71,901	34%	815
3. Wholesale, Transport, other Utilities	67	32,771	17,344	8%	489
4. Retail stores	42	13,485	7,545	3%	321
5. Offices, Hotels, Health, Services	127	99,199	66,355	25%	781
6. Schools	159	55,918	18,668	14%	352
7. Government, Entertainment, Other Services	49	35,835	17,969	9%	731
TOTAL	650	395,185	205,998	100%	608

Table 2.2 shows comparable information on CPP enrollment for SCE. SCE's enrollment expanded from just 15 customer accounts in 2006, to 44 in 2007, 201 in 2008, and 485 in

[13] Some customers are located outside of the 10 CAISO-designated LCAs. These customers are grouped into separate categories for the purposes of this analysis.
[14] Some business "customers," such as a retail company like Wal-Mart, have multiple establishments, or "service accounts," within a utility service area. The enrollment numbers reported here count each service account separately.
[15] Customer-level demand is calculated as the average of the monthly maximum demands during the program months.
[16] Average hourly usage is calculated as the sum of usage during the program months divided by the number of hours during the program months.

2009. Total maximum demand of those customers enrolled in CPP in 2009 amounted to about 283 MW. Manufacturers made up the bulk of CPP enrollment.

Table 2.2: CPP Enrollees by Industry group – *SCE*

Industry Type	Number of SAIDs	Sum of Max kW	Sum of Avg. kWh	% of Max kW	Avg. Size (kW)
1. Agriculture, Mining & Construction	24	10,904	3,164	4%	454
2. Manufacturing	221	138,740	51,307	49%	628
3. Wholesale, Transport, other Utilities	54	52,185	24,264	18%	966
4. Retail stores	35	20,417	8,821	7%	583
5. Offices, Hotels, Health, Services	44	19,651	6,621	7%	447
6. Schools	99	36,989	11,949	13%	374
7. Government, Entertainment, Other Services	8	3,679	1,160	1%	460
Total	485	282,564	107,286	100%	583

Table 2.3 shows comparable information for enrollments in the default CPP program at SDG&E. SDG&E's enrollment in default CPP has increased from 1,320 customer accounts in 2008 to 1,580 in 2009, accounting for over 600 MW of maximum demand. The average summer maximum demand for enrolled accounts is 387 kW. The Offices, Hotels, Health care, and Services group contains the largest share of service accounts and demand, followed by Wholesale, Transportation, and Other utilities.

Table 2.3: CPP Enrollees by Industry Group – *SDG&E (2009)*

Industry Type	Number of SAIDs	Sum of Max kW	Sum of Avg. kWh	% of Max kW	Avg. Size (kW)
1. Agriculture, Mining & Construction	19	11,687	4,531	2%	615
2. Manufacturing	222	92,696	48,210	15%	418
3. Wholesale, Transport, other Utilities	266	120,208	45,161	20%	452
4. Retail stores	128	42,644	26,660	7%	333
5. Offices, Hotels, Health, Services	481	220,702	134,943	36%	459
6. Schools	267	54,415	20,236	9%	204
7. Government, Entertainment, Other Services	190	67,575	34,192	11%	356
8. Other/Unclassified	7	857	570	0%	122
TOTAL	1,580	610,784	314,504	100%	387

Tables 2.4 and 2.5 show CPP enrollment by local capacity area for PG&E and SCE respectively. (SDG&E's service territory consists of a single LCA.)

Table 2.4: CPP Enrollees by Local Capacity Area – *PG&E (2009)*

Local Capacity Area	Number of SAIDs	Sum of Max kW	Sum of Avg. kWh	% of Max kW	Avg. Size (kW)
Greater Bay Area	370	254,124	148,423	64%	687
Greater Fresno	60	30,624	11,130	8%	510
Humboldt	14	3,999	2,395	1%	286
Kern	12	7,408	3,294	2%	617
Northern Coast	51	24,604	11,097	6%	482
Sierra	37	16,986	7,968	4%	459
Stockton	13	7,663	2,381	2%	589
Other	93	49,777	19,310	13%	535
TOTAL	650	395,185	205,998	100%	608

Table 2.5: CPP Enrollees by Local Capacity Area – *SCE*

Local Capacity Area	Number of SAIDs	Sum of Max kW	% of Max kW	Avg. Size (kW)
LA Basin	398	237,546	84%	597
Outside LA Basin	27	13,199	5%	489
Ventura	60	31,819	11%	530
Total	485	282,564	100%	583

2.3 Program events

Table 2.5 lists CPP event days for each of the utilities in 2009. PG&E and SCE each called 12 CPP events (PG&E's first event was a test event), while SDG&E called 8 events. The utilities often called events on different days, though there was some overlap, particularly in the last week of August. PG&E's events started earliest in the summer, and ended earliest in the season, while SDG&E's events did not begin until late August and extended into late September.

Table 2.6: CPP Events – 2009

Date	PG&E	SCE	SDG&E
6/18		1 (Test)	
6/29	1		
6/30	2		
7/13	3		
7/14	4		
7/15		2	
7/16	5		
7/17		3	
7/20		4	
7/21	6		
7/22		5	
7/27	7	6	
7/28		7	
8/10	8		
8/11	9		
8/18	10		
8/20		8	
8/27	11	9	1
8/28	12	10	2
8/29			3*
8/31			4
9/1		11	
9/2		12	
9/3			5
9/4			6
9/24			7
9/25			8

* Saturday

3. Study methodology

Direct estimates of total program-level ex post load impacts for each utility's CPP program were developed from the coefficients of individual customer regression equations. These equations were estimated for each customer account using interval load data from the summer months for 2009, 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.[17]

[17] An important but relatively minor factor that required attention with the interval load data was the issue of accounting for the change from standard time to daylight savings time. Each of the utilities used somewhat different conventions in maintaining their load data. SCE in particular leaves its data in standard time throughout the year. This simplifies the problem of dealing with two special days of either 23 or 25 hours, but requires the analyst to adjust the data to ensure consistency with the definition of specific event hours during the summer period.

3.1 Primary regression equation specifications

The regression equations were based on models of hourly loads as functions of a list of variables designed to control for factors that affect consumers' hourly usage levels, 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 (CDH))
- Event indicators—Hourly indicator variables interacted with event indicators, in order to provide estimates of the hourly load impacts during each event.

The model that was used for the PG&E and SCE customers is shown below.

$$
\begin{aligned}
Q_t &= a + \sum_{Evt=1}^{E} \sum_{i=1}^{24} (b_{i,Evt}^{CPP} \times h_{i,t} \times CPP_t) + b^{MornLoad} \times MornLoad_t + \sum_{i=1}^{24} (b_i^{CDH} \times h_{i,t} \times CDH_t) \\
&+ \sum_{i=2}^{24} (b_i^{MON} \times h_{i,t} \times MON_t) + \sum_{i=2}^{24} (b_i^{FRI} \times h_{i,t} \times FRI_t) + \sum_{i=2}^{24} (b_i^{h} \times h_{i,t}) + \sum_{i=2}^{5} (b_i^{DTYPE} \times DTYPE_{i,t}) \\
&+ \sum_{i=6}^{10} (b_i^{MONTH} \times MONTH_{i,t}) + b_t^{Summer} \times Summer_t + \sum_{i=1}^{24} (b_i^{CDH,S} \times h_{i,t} \times Summer_t \times CDH_t) \\
&+ \sum_{i=2}^{24} (b_i^{MON,S} \times h_{i,t} \times Summer_t \times MON_t) + \sum_{i=2}^{24} (b_i^{FRI,S} \times h_{i,t} \times Summer_t \times FRI_t) \\
&+ \sum_{i=2}^{24} (b_i^{h,S} \times h_{i,t} \times Summer_t) + b^{OTH} \times OTH_t + e_t
\end{aligned}
$$

In this equation, Q_t represents the amount of usage in hour t for a customer enrolled in CPP prior to the last event date; the b's are estimated parameters; $h_{i,t}$ is a dummy variable for hour i; CPP_t is an indicator variable for program event days; CDH_t is cooling degree hours;[18] 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; $Summer_t$ is a variable indicating summer months (defined as mid-June through mid-August)[19], which is interacted with the weather and hourly profile variables; OTH_t is a dummy variable indicating an event hour for a non-CPP demand response program in which the customer is also enrolled[20]; 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

[18] 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. Our previous studies used cooling degree days with a 65 degree threshold (CDD65). Our review of the results this year found that using CDH50 in place of CDD65 produced implied event-day reference loads that better reflected observed usage patterns and levels on hot, non-event days.

[19] This variable was initially designed to reflect the load changes that occur when schools are out of session. We have found the variables to a useful part of the base specification, as they do not appear to harm load impact estimates even in cases in which the customer does not change its usage level or profile during the summer months.

[20] For DBP, the variable is equal to one if it is an event hour and the customer submitted a bid for that hour.

account for the level of load on a particular day. Because of the autoregressive nature of the morning load variable, no further correction for serial correlation was performed in these models.

For SDG&E, initial regression results suggested that the equations were not adequately capturing mid-day weather effects on the hottest days of the summer, which were also SDG&E CPP event days. We therefore added two sets of 24 variables in which hour dummies (for the summer and non-summer periods) were interacted with the *square* of cooling degree hours. This model is discussed further in the Validity Assessment section of this report.

Separate models were estimated for each service account. The load impacts were aggregated across customers to arrive at program-level load impacts and results by industry group and local capacity area (LCA).

3.2 Customer-level screening of results

As noted above, separate models were estimated for each enrolled customer. We screened the customer-level models for the effects of omitted variable bias. That is, while we include a large number of variables to account for systematic variations in customer load levels (e.g., by time of day, or day of week), many other factors may affect a customer's usage in a particular hour. For example, we have found that the load shapes for sports arenas in the PG&E area are difficult to predict because the load changes substantially on days on which they apparently host events, but we do not have the information to design variables to account for the occurrence of such events. For these customers, we sometimes observe large positive load impacts and sometimes large negative load changes in the hours following CPP event windows. However, these estimated "load impacts" are clearly unrelated to the existence of the CPP event, but rather artifacts of whether the arena happened to host an event on the day of the CPP event.

As a result, we recommend that the appropriate procedure is to set CPP load impacts equal to zero for those accounts. (We determine whether the load impacts are "real" by examining the daily load profiles for event and similar non-event days. This process is discussed further in the Validity Assessment section of this report.)

The load impact estimates for schools are most consistently affected by omitted variable bias. For example, when school is in session, the load profile is higher overall and displays a lower daily load factor than when school is not in session. We have found it very difficult to devise a generalized specification (i.e., one that is not developed one customer at a time) that can properly account for these effects. We have examined customer-level load data (using the day-matching technique) for many of the school accounts, and we cannot find any convincing evidence of load reductions during CPP events. Any estimated load impacts (positive and negative) appear to be due to errors in estimating a proper reference load for the event day. Therefore, we have zeroed out all of the estimated load impacts for schools for both PG&E and SDG&E.

We also excluded a few non-schools customers' load impacts from the program load-impact results. There were 9 such customers for PG&E, 4 for SCE, and 16 for SDG&E.

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, due to substantial day-to-day changes in consumers' hourly demands, which are not always easily explained by variables common to all customers. The uncertainty-adjusted load impacts are calculated by adding the customer-level variances (the square of the standard errors of the estimated load impact coefficients) and calculating the scenarios for each hour assuming normally distributed load impacts.

4. Detailed study findings

The primary objective of this task was to estimate the aggregate and per-customer CPP event-day load impacts for each utility.[21] Each utility's section begins with a summary of *average hourly load impacts* by event, and by industry type and local capacity area for the average event. This is followed by tables of hourly load impacts for an *average event* (also referred to as a "typical event day") in the format required by the Load Impact Protocols adopted by the California Public Utilities Commission (CPUC) in Decision (D.) 08-04-050 ("the Protocols"), including risk-adjusted load impacts at different probability levels, and figures that illustrate ranges of load impacts. Assessments of the effect of TA/TI and AutoDR on load impacts follow. The full compliment of Protocol tables showing hourly load impacts by industry type and LCA is provided in an Excel table generator in an associated electronic file.

As a high-level summary, we present the average per-customer event-hour load impact for each utility below.

1. PG&E = 13 kW
2. SCE = 52 kW
3. SDG&E = 14 kW

4.1 PG&E Ex Post Load Impacts

4.1.1 Average hourly load impacts

Aggregate CPP load impacts for PG&E were estimated on the basis of individual customer regression equations using data for all CPP participants. Table 4.1 summarizes the average hourly load impacts across all participants during the six-hour event periods for PG&E's twelve CPP event days in 2009. The table shows the average hourly *observed* load in the event period (column 6), the *estimated reference load* (column 5) and *load impact* (column 7), and load impact as a *percent* of the reference load. The mean value across events of the average hourly load impacts is 8.4 MW, and load impacts range from 4.0 to 12.6 MW, with a standard deviation of 2.4 MW. The average percent load impact ranges from 1.7 percent of the estimated reference load to 4.5 percent, and averages 3.3 percent, with a standard

[21] The main body of the report focuses on aggregate program impacts. The full set of tables required by the Protocols, including load impacts by event day and local capacity area, are provided separately in Excel files.

deviation of 0.9 percent.[22] The average load impact in 2009, along with the reference load level, was smaller than the comparable value in 2008. However, the load impacts were generally more consistent across events in 2009 than in 2008. This result is likely due in large part to the careful screening of estimated load impacts for a small number of customer accounts that were judged to be unreliable for several events. Figure 4.1 illustrates the range of estimated average hourly load impacts across events.

Table 4.1: Average Hourly CPP Load Impacts (kW) by Event – *PG&E (2009)*

Event	Date	Day of Week	Count	Estimated Reference Load (kW)	Observed Load (kW)	Estimated Load Impact (kW)	% LI
1	6/29/2009	Monday	646	254,617	243,226	11,391	4.5%
2	6/30/2009	Tuesday	646	244,558	238,668	5,890	2.4%
3	7/13/2009	Monday	646	248,084	241,193	6,890	2.8%
4	7/14/2009	Tuesday	645	262,706	253,473	9,233	3.5%
5	7/16/2009	Thursday	645	248,140	240,004	8,136	3.3%
6	7/21/2009	Tuesday	646	238,681	229,896	8,785	3.7%
7	7/27/2009	Monday	646	239,394	235,396	3,998	1.7%
8	8/10/2009	Monday	640	260,197	253,353	6,843	2.6%
9	8/11/2009	Tuesday	639	249,294	240,937	8,357	3.4%
10	8/18/2009	Tuesday	638	259,068	251,033	8,035	3.1%
11	8/27/2009	Thursday	632	277,431	266,598	10,833	3.9%
12	8/28/2009	Friday	632	288,784	276,211	12,573	4.4%
		Average	**642**	**255,913**	**247,499**	**8,414**	**3.3%**
		Std. Dev.	**5**	**15,027**	**13,359**	**2,406**	**0.9%**

[22] Note that the percent load impacts for the event periods are calculated relative to the reference loads in those periods. These reference loads represent the coincident loads of the enrolled customers, and thus differ from the non-coincident maximum demand values shown in the tables of enrollment.

Figure 4.1: Average Hourly CPP Load Impacts (kW) by Event – *PG&E (2009)*

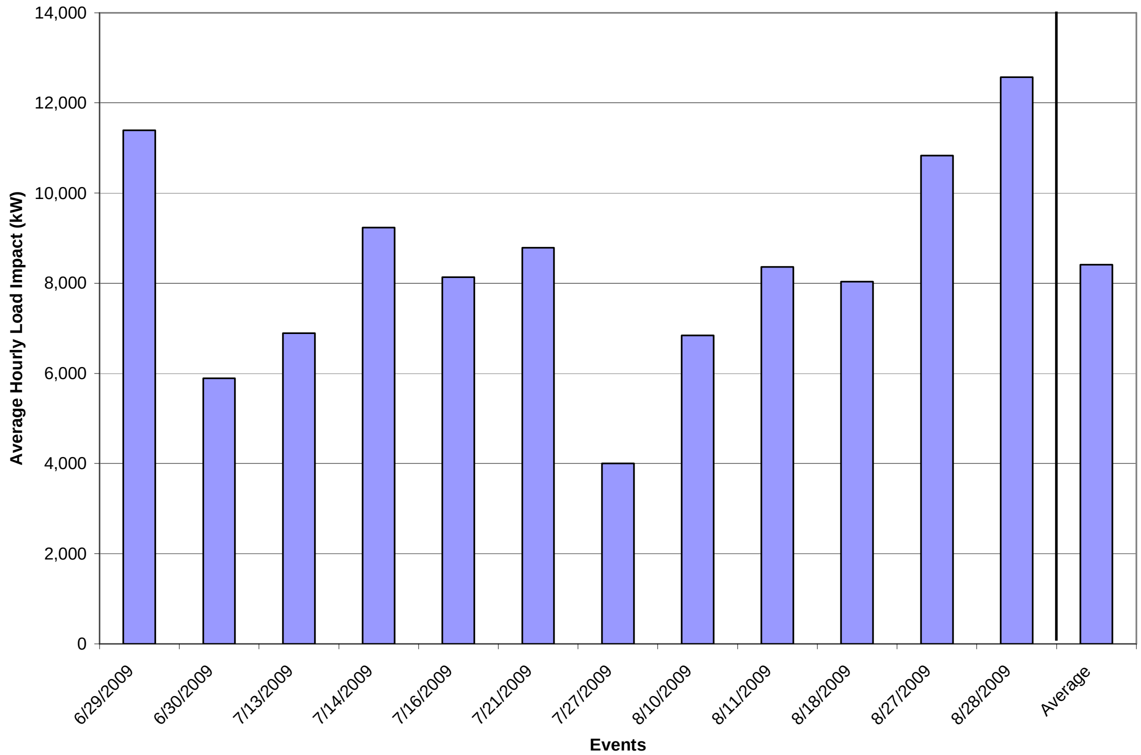


Table 4.2 shows the distribution of estimated load impacts (averaged across all event days), in levels and percentages, by industry group. The Manufacturing; Retail stores; and Offices, Hotels, Finance and Services industry types provided the largest load impacts, while Retail stores provided the largest percentage load impacts.

Table 4.2: Average Hourly CPP Load Impacts (kW) – *by Industry Type (PG&E)*

Industry Group	Count	Estimated Reference Load (kW)	Observed Load (kW)	Estimated Load Impact (kW)	% LI
1. Agriculture, Mining & Construction	39	4,021	3,760	261	6.5%
2. Manufacturing	164	87,055	83,351	3,704	4.3%
3. Wholesale, Transport, other Utilities	67	15,696	15,074	621	4.0%
4. Retail stores	42	11,253	9,802	1,451	12.9%
5. Offices, Hotels, Health, Services	124	85,522	84,105	1,416	1.7%
6. Schools	158	26,765	26,765	0	0.0%
7. Gov't, Entertainment, Other Services	48	25,601	24,642	959	3.7%
Total	**642**	**255,913**	**247,499**	**8,414**	**3.3%**

Table 4.3 shows the distribution of average hourly load impact for the average event by LCA.

Table 4.3: Average Hourly CPP Load Impacts (kW) – *by LCA (PG&E)*

Local Capacity Area	Count	Estimated Reference Load (kW)	Observed Load (kW)	Estimated Load Impact (kW)	% LI
Greater Bay Area	364	189,436	185,468	3,967	2.1%
Greater Fresno	59	14,527	14,167	360	2.5%
Humboldt	14	2,769	2,714	55	2.0%
Kern	12	3,648	3,493	155	4.3%
Northern Coast	51	15,171	14,274	898	5.9%
Sierra	37	7,938	7,533	406	5.1%
Stockton	12	1,705	1,688	16	0.9%
Other	93	20,719	18,161	2,557	12.3%
Total	**642**	**255,913**	**247,499**	**8,414**	**3.3%**

4.1.2 Hourly load impacts

Table 4.4 presents hourly values of the estimated reference load, observed load, load impacts, and uncertainty-adjusted load impacts for the average event day at the overall program level, in the manner required by the Protocols. Event hours of HE 13 – 18 are indicated by shading. The average event-day estimated reference load ranges from about 236 MW at the end of the event window to 265 MW at the beginning of the event. Hourly load impacts range from about 7.7 to 9.1 MW over the event period, or 3 to 3.5 percent of the estimated reference load. The 10th and 90th percentile values range 22 to 27 percent below and above the *average* load impact values.

Table 4.4: Hourly Load Impacts for Average CPP Event Day in 2009 – *PG&E*

Hour Ending	Estimated Reference Load (kWh/hr)	Observed Event-Day Load (kWh/hr)	Estimated Load Impact (kWh/hr)	Weighted Average Temperature (°F)	Uncertainty Adjusted Impact (kWh/hr)- Percentiles				
					10th%ile	30th%ile	50th%ile	70th%ile	90th%ile
1	178,440	177,161	1,280	64	-638	495	1,280	2,064	3,197
2	175,110	174,619	491	63	-1,474	-313	491	1,295	2,456
3	172,619	172,239	380	62	-1,582	-422	380	1,183	2,343
4	174,138	173,395	743	62	-1,216	-59	743	1,544	2,702
5	181,753	180,768	985	61	-978	182	985	1,788	2,947
6	194,852	193,704	1,149	61	-813	346	1,149	1,952	3,111
7	213,005	212,048	957	61	-999	157	957	1,758	2,913
8	230,804	230,476	328	63	-1,640	-477	328	1,133	2,296
9	244,513	244,233	281	66	-1,702	-531	281	1,092	2,263
10	256,466	256,279	187	69	-1,810	-630	187	1,005	2,185
11	265,547	264,850	697	73	-1,298	-119	697	1,513	2,692
12	267,725	265,684	2,040	77	45	1,224	2,040	2,857	4,036
13	264,826	255,692	9,134	80	7,117	8,309	9,134	9,960	11,151
14	266,947	257,917	9,029	82	7,004	8,201	9,029	9,858	11,055
15	265,011	257,350	7,662	84	5,614	6,824	7,662	8,500	9,710
16	255,771	247,579	8,192	84	6,160	7,361	8,192	9,024	10,224
17	246,794	238,255	8,540	84	6,531	7,718	8,540	9,361	10,548
18	236,127	228,202	7,925	82	5,896	7,095	7,925	8,755	9,953
19	224,724	221,952	2,772	80	772	1,954	2,772	3,590	4,772
20	217,510	217,228	283	76	-1,719	-536	283	1,102	2,285
21	212,908	213,107	-199	72	-2,205	-1,020	-199	621	1,806
22	206,156	206,206	-50	69	-2,060	-872	-50	773	1,961
23	196,936	196,574	363	68	-1,646	-459	363	1,184	2,371
24	189,468	189,195	272	66	-1,736	-550	272	1,094	2,281
	Reference Energy Use (kWh)	Observed Event-Day Energy Use (kWh)	Change in Energy Use (kWh)	Cooling Degree Hours (Base 75 oF)	Uncertainty Adjusted Impact (kWh/hour) - Percentiles				
					10th	30th	50th	70th	90th
Daily	5,338,149	5,274,709	63,440	54.6	n/a	n/a	n/a	n/a	n/a

Figure 4.2 illustrates the reference load, observed load and estimated load impact (right axis) for the average CPP event. Figure 4.3 shows the range of hourly load impacts across events.

Figure 4.2: Hourly Load Impacts for Average CPP Event Day in 2009 – *PG&E*

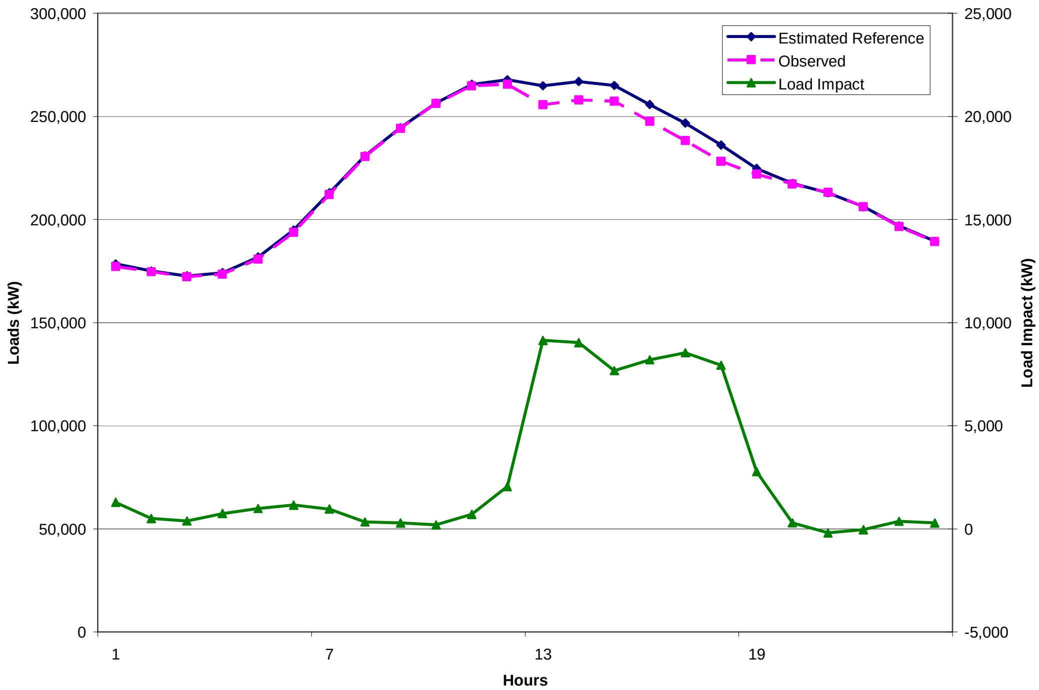
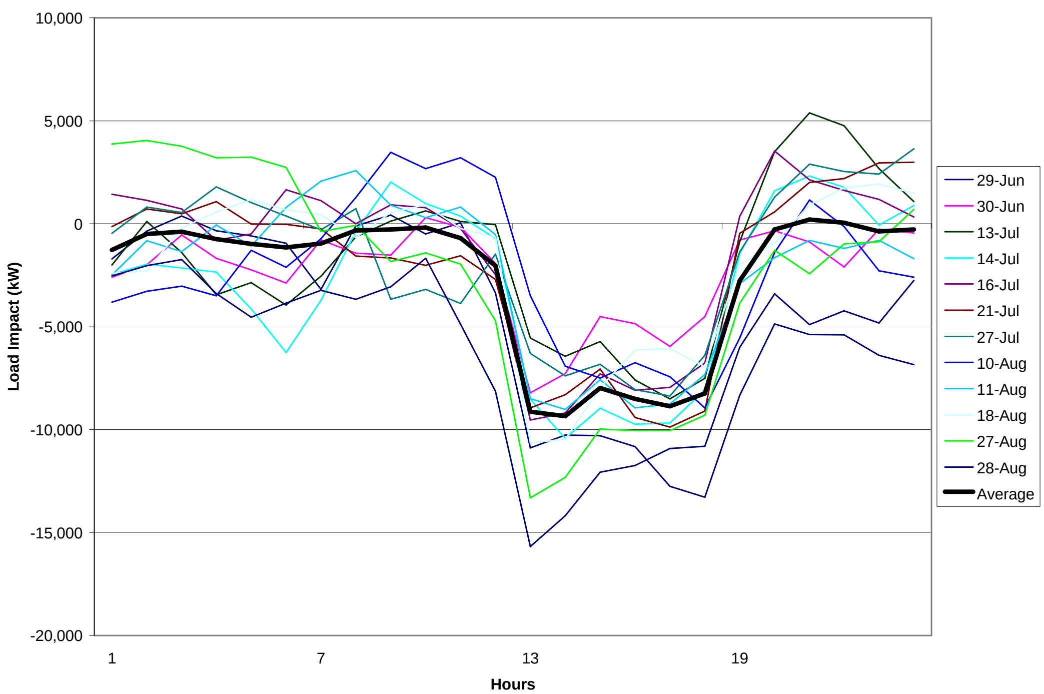


Figure 4.3: Hourly CPP Load Impacts, by Event – *PG&E*



4.2 SCE Ex Post Load Impacts

4.2.1 Average hourly load impacts

Table 4.5 summarizes the average hourly load impacts during the event period for SCE's twelve CPP event days in 2009. The load impacts are noticeably consistent across events, as illustrated in Figure 4.4, with an average hourly load reduction of nearly 25 MW, or about 19 percent of the estimated reference load. The standard deviation of the average hourly load impacts across events is 2.7 MW, or about 2 percent of the reference load.

Table 4.5: Average Hourly CPP Load Impacts (kW) by Event – *SCE*

Event	Date	Day of Week	Count	Estimated Reference Load (kW)	Observed Load (kW)	Estimated Load Impact (kW)	% LI
1	6/18/2009	Thursday	449	120,531	94,732	25,798	21.4%
2	7/15/2009	Wednesday	478	125,297	101,119	24,178	19.3%
3	7/17/2009	Friday	479	116,154	95,550	20,604	17.7%
4	7/20/2009	Monday	478	125,405	103,243	22,162	17.7%
5	7/22/2009	Wednesday	479	129,791	103,653	26,137	20.1%
6	7/27/2009	Monday	480	123,575	99,722	23,853	19.3%
7	7/28/2009	Tuesday	480	123,469	101,636	21,833	17.7%
8	8/20/2009	Thursday	479	125,241	97,813	27,428	21.9%
9	8/27/2009	Thursday	479	142,282	116,846	25,437	17.9%
10	8/28/2009	Friday	479	140,261	118,636	21,625	15.4%
11	9/1/2009	Tuesday	478	144,536	115,178	29,358	20.3%
12	9/2/2009	Wednesday	478	147,867	120,535	27,332	18.5%
		Average	**476**	**130,367**	**105,722**	**24,645**	**18.9%**
		Std. Dev.	**9**	**10,515**	**9,393**	**2,726**	**2.1%**

Figure 4.4: Average Hourly CPP Load Impacts (kW) by Event – *SCE*

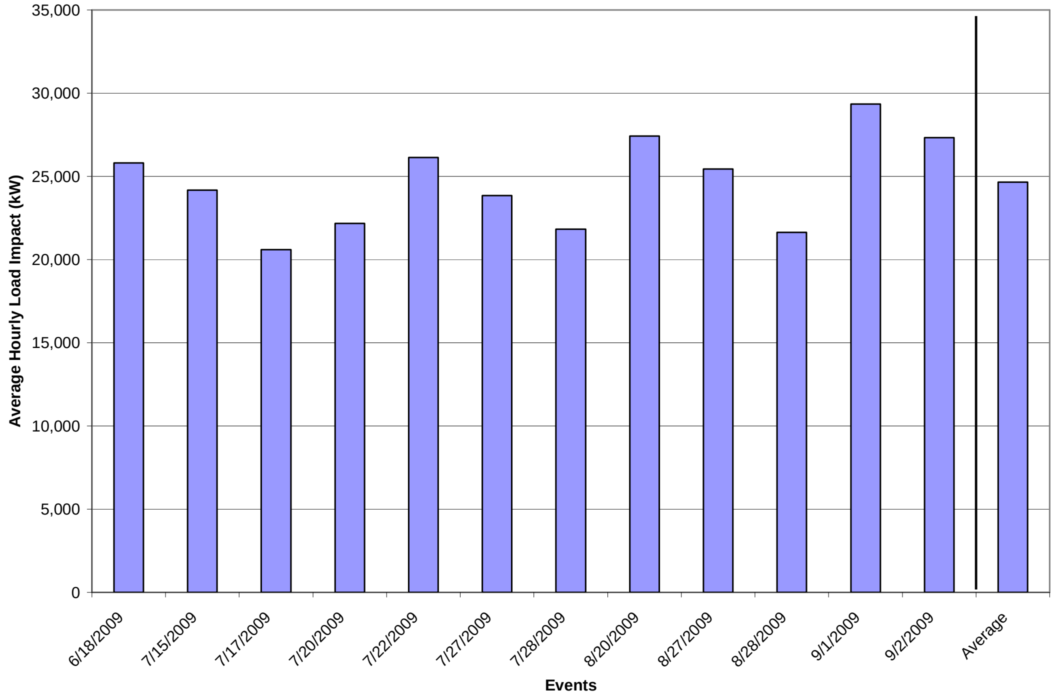


Table 4.6 summarizes average hourly load impacts by industry type for the average event, while Table 4.7 presents load impacts by LCA. Manufacturing customers made up more than half of the total reference load and accounted for the bulk of the load impacts. Nearly all of the load impacts were generated in the LA Basin.

Table 4.6: Average Hourly CPP Load Impacts (kW) – *by Industry Type* (SCE)

Industry Group	Count	Estimated Reference Load (kW)	Observed Load (kW)	Estimated Load Impact (kW)	% LI
1. Agriculture, Mining & Construction	24	3,068	2,677	392	12.8%
2. Manufacturing	217	65,767	48,020	17,747	27.0%
3. Wholesale, Transport, other Utilities	53	16,791	12,490	4,302	25.6%
4. Retail stores	34	13,602	12,653	949	7.0%
5. Offices, Hotels, Health, Services	44	9,564	8,957	607	6.4%
6. Schools	97	19,961	19,961	0	0.0%
7. Gov't, Entertainment, Other Services	8	1,614	965	649	40.2%
Total	**476**	**130,367**	**105,722**	**24,645**	**18.9%**

Table 4.7: Average Hourly CPP Load Impacts (kW) – *by LCA* (SCE)

Local Capacity Area	Count	Estimated Reference Load (kW)	Observed Load (kW)	Estimated Load Impact (kW)	% LI
LA Basin	390	111,050	89,925	21,125	19.0%
Outside LA Basin	27	4,251	4,057	194	4.6%
Ventura	59	15,067	11,740	3,327	22.1%
Total	**476**	**130,367**	**105,722**	**24,645**	**18.9%**

4.2.2 Hourly load impacts

Table 4.8 summarizes the hourly load impacts for the average CPP event. The hourly average event-day load impacts ranged from approximately 19 MW in the last hour of the event period to 29 MW in the first two hours. The load impacts represent percentages of the reference load ranging from about 18 to 20 percent. The 10^{th} and 90^{th} percentile load impacts range from 9 to 13 percent around the average load impact, with the values increasing toward the end of the event period.

Table 4.8: Hourly Load Impacts for Average CPP Event Day – *SCE*

Hour Ending	Estimated Reference Load (kWh/hr)	Observed Event-Day Load (kWh/hr)	Estimated Load Impact (kWh/hr)	Weighted Average Temperature (°F)	Uncertainty Adjusted Impact (kWh/hr)- Percentiles				
					10th%ile	30th%ile	50th%ile	70th%ile	90th%ile
1	98,226	97,045	1,181	70	-1,265	180	1,181	2,182	3,627
2	95,439	94,486	953	69	-1,525	-61	953	1,967	3,431
3	92,724	93,081	-357	68	-2,834	-1,371	-357	656	2,120
4	93,855	96,003	-2,148	67	-4,625	-3,161	-2,148	-1,135	328
5	104,420	108,140	-3,720	67	-6,198	-4,734	-3,720	-2,706	-1,242
6	120,828	124,501	-3,673	67	-6,155	-4,688	-3,673	-2,657	-1,191
7	137,484	139,113	-1,630	66	-4,117	-2,648	-1,630	-612	858
8	150,194	151,499	-1,305	67	-3,796	-2,324	-1,305	-286	1,186
9	156,895	157,092	-197	69	-2,687	-1,216	-197	822	2,293
10	162,798	162,834	-35	73	-2,520	-1,052	-35	981	2,450
11	167,070	166,077	993	77	-1,490	-23	993	2,010	3,477
12	157,513	147,537	9,976	81	7,497	8,961	9,976	10,990	12,454
13	147,732	119,012	28,720	84	26,246	27,708	28,720	29,732	31,194
14	147,568	118,530	29,038	86	26,568	28,028	29,038	30,049	31,509
15	139,436	113,331	26,106	88	23,637	25,095	26,106	27,116	28,575
16	127,007	103,569	23,438	88	20,967	22,427	23,438	24,449	25,909
17	114,862	93,702	21,160	88	18,693	20,150	21,160	22,169	23,626
18	105,599	86,188	19,411	87	16,945	18,402	19,411	20,420	21,876
19	107,398	99,181	8,217	85	5,746	7,206	8,217	9,228	10,688
20	115,332	111,231	4,101	82	1,630	3,090	4,101	5,113	6,573
21	118,525	117,248	1,276	78	-1,187	269	1,276	2,284	3,739
22	113,554	112,933	621	75	-1,843	-387	621	1,629	3,084
23	105,787	105,376	411	73	-2,056	-599	411	1,421	2,879
24	103,740	103,214	526	72	-1,945	-485	526	1,537	2,997
	Reference Energy Use (kWh)	Observed Event-Day Energy Use (kWh)	Change in Energy Use (kWh)	Cooling Degree Hours (Base 75 oF)	Uncertainty Adjusted Impact (kWh/hour) - Percentiles				
					10th	30th	50th	70th	90th
Daily	2,983,986	2,820,924	163,063	99.1	n/a	n/a	n/a	n/a	n/a

Figure 4.5 illustrates the pattern of the reference load, observed load, and load impacts for the average event day, showing the decline in hourly load impacts over the event period. Figure 4.6 shows the rather tight range of estimated load impacts across events.

Figure 4.5: Hourly Load Impacts for Average CPP Event Day in 2009 – *SCE*

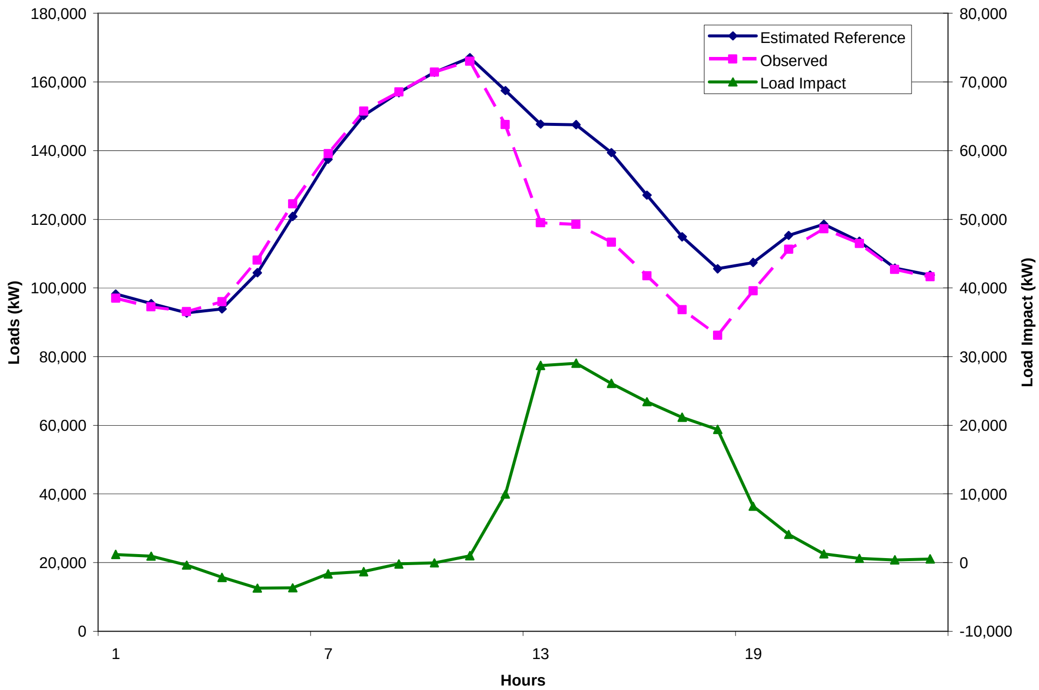
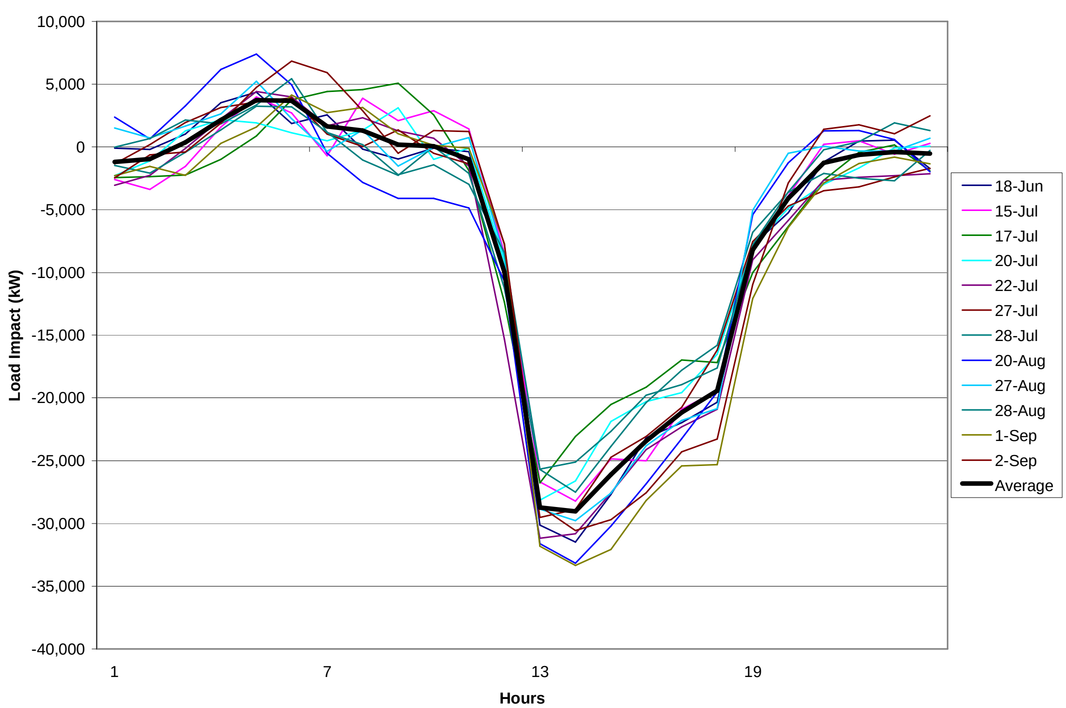


Figure 4.6: Hourly CPP Load Impacts, by Event – *SCE*



4.3 SDG&E Ex Post Load Impacts

4.3.1 Average hourly load impacts

Table 4.9 summarizes the average hourly load impacts during the event period for SDG&E's eight CPP event days in 2009. The load impacts ranged from 19.8 MW to 29.3 MW across the seven weekday events, with an average of 23.3 MW, or about 5.6 percent of the CPP reference load, as shown in Figure 4.7.[23] Load impacts were somewhat less than average for the one Saturday event (August 29) and the two late-September events. The standard deviation around the average load impact value is 3.6 MW, or about 0.9 percent of the reference load.

Table 4.9: Average Hourly CPP Load Impacts (kW) by Event – *SDG&E* (2009)

Event	Date	Day of Week	Count	Estimated Reference Load (kW)	Observed Load (kW)	Estimated Load Impact (kW)	% LI
1	8/27/2009	Thursday	1,576	426,433	400,046	26,387	6.2%
2	8/28/2009	Friday	1,576	422,212	400,040	22,173	5.3%
3	8/29/2009	Saturday	1,576	346,827	327,859	18,968	5.5%
4	8/31/2009	Monday	1,576	428,554	406,151	22,403	5.2%
5	9/3/2009	Thursday	1,576	456,613	427,311	29,302	6.4%
6	9/4/2009	Friday	1,576	438,160	412,065	26,094	6.0%
7	9/24/2009	Thursday	1,576	426,584	406,784	19,799	4.6%
8	9/25/2009	Friday	1,576	405,449	384,503	20,945	5.2%
		Average	**1,576**	**418,854**	**395,595**	**23,259**	**5.6%**
		Std. Dev.	**0**	**32,489**	**29,916**	**3,625**	**0.9%**

[23] It should be noted that SDG&E allows joint participation in CPP and the Capacity Bidding Program (CBP) day-of (DO) program type. If CPP and CBP-DO events are called on the same day, customer accounts that are enrolled in both programs continue to face CPP prices on that day, and do not receive energy credits for CBP load reductions. However, the CPUC has ruled that for resource adequacy purposes, capacity-based program load impacts receive a higher priority than those of energy-based programs. Contemporaneous CPP and CBP-DO events were called three times in 2009, on August 27, August 28, and September 3. We estimate that the average hourly load impacts of those customer accounts that were enrolled in both programs provided approximately 4 MW of load impacts. Thus, for resource adequacy purposes, the estimated CPP load impacts on those three days should be reduced by approximately 4 MW.

Figure 4.7: Average Hourly CPP Load Impacts (kW) by Event – *SDG&E* (2009)

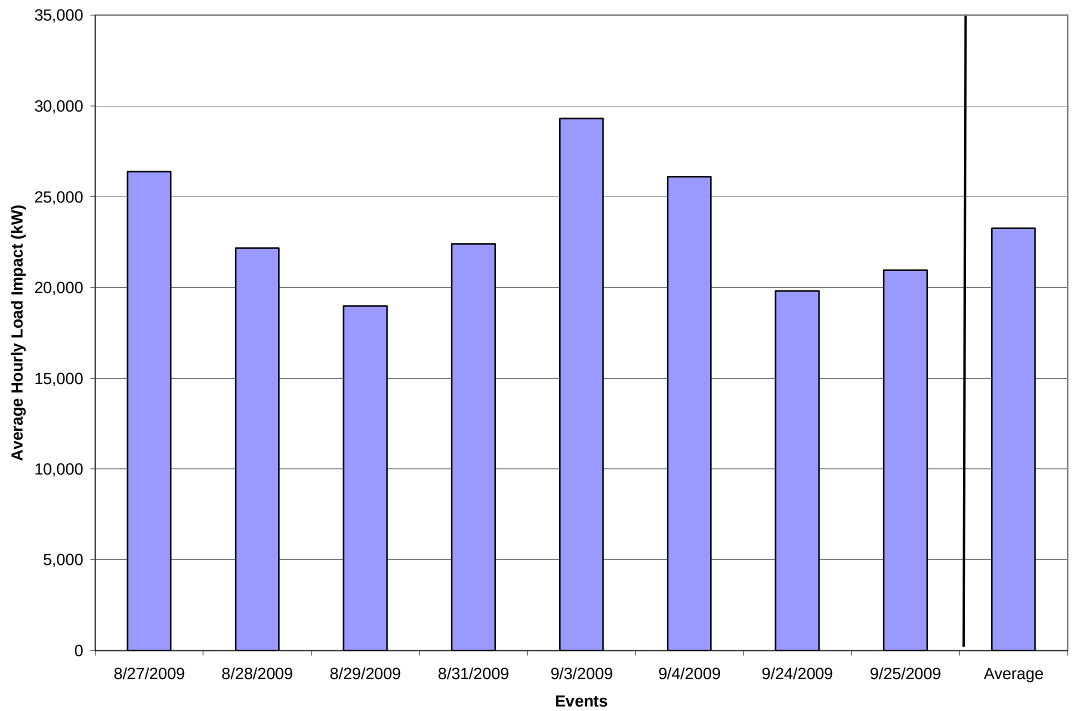


Table 4.10 summarizes load impacts by industry type for the average event. The largest load impacts were provided by the Offices, Hotels, Health and Services; and Wholesale, Transportation and Utilities (largely water utilities) industry groups.[24]

[24] Note that the small negative estimated load impact for the "Other/Unknown" industry group indicates that the regression models estimated a higher than expected load on the average CPP event day. These estimates were likely not statistically significant.

Table 4.10: Average Hourly CPP Load Impacts (kW) – *by Industry Type (SDG&E)*

Industry Group	Count	Estimated Reference Load (kW)	Observed Load (kW)	Estimated Load Impact (kW)	% LI
1. Agriculture, Mining & Construction	19	4,835	3,760	1,075	22.2%
2. Manufacturing	220	59,506	56,533	2,973	5.0%
3. Wholesale, Transport, other Utilities	265	49,186	42,773	6,412	13.0%
4. Retail stores	128	38,959	36,814	2,145	5.5%
5. Offices, Hotels, Health, Services	480	180,185	172,249	7,937	4.4%
6. Schools	267	41,546	41,546	0	0.0%
7. Gov't, Entertainment, Other Services	190	44,020	41,268	2,752	6.3%
8. Other or Unknown	7	617	653	-35	-5.7%
Total	**1,576**	**418,854**	**395,595**	**23,259**	**5.6%**

4.3.2 Hourly load impacts

Table 4.11 summarizes the hourly load impacts for the average seven-hour CPP event. The hourly average event-day load impacts range from approximately 27 MW in the first hour of the event period to 21 MW in the last hour. The load impacts represent percentages of the reference load ranging from about 5 to 6.3 percent. The 10^{th} and 90^{th} percentile load impacts range from 13 to 16 percent around the average load impact, with the values increasing toward the end of the event period.

Table 4.11: CPP Total Load Impacts for Average Event Day – *SDG&E*

Hour Ending	Estimated Reference Load (kWh/hr)	Observed Event-Day Load (kWh/hr)	Estimated Load Impact (kWh/hr)	Weighted Average Temperature (°F)	Uncertainty Adjusted Impact (kWh/hr)- Percentiles				
					10th%ile	30th%ile	50th%ile	70th%ile	90th%ile
1	269,047	272,211	-3,164	71	-6,166	-4,393	-3,164	-1,935	-161
2	257,728	258,328	-600	70	-3,661	-1,853	-600	653	2,462
3	251,726	253,171	-1,446	69	-4,567	-2,723	-1,446	-168	1,676
4	253,364	253,241	123	70	-3,059	-1,179	123	1,425	3,305
5	262,769	261,576	1,192	69	-1,958	-96	1,192	2,481	4,342
6	284,852	283,507	1,346	69	-1,931	5	1,346	2,686	4,622
7	315,222	311,821	3,401	69	42	2,027	3,401	4,776	6,761
8	342,012	340,707	1,305	73	-2,237	-144	1,305	2,755	4,848
9	373,892	373,385	507	78	-3,080	-961	507	1,974	4,094
10	402,383	400,313	2,070	82	-1,869	458	2,070	3,682	6,009
11	424,167	414,142	10,026	84	6,415	8,548	10,026	11,503	13,636
12	433,875	406,471	27,404	86	23,669	25,876	27,404	28,932	31,138
13	433,385	410,123	23,262	86	19,824	21,855	23,262	24,669	26,700
14	434,848	410,788	24,061	85	20,890	22,763	24,061	25,358	27,231
15	432,073	406,567	25,506	85	22,181	24,145	25,506	26,866	28,831
16	415,959	395,452	20,507	85	17,130	19,125	20,507	21,889	23,884
17	401,421	380,426	20,995	84	17,788	19,683	20,995	22,307	24,202
18	380,417	359,339	21,079	81	18,044	19,837	21,079	22,321	24,113
19	353,252	347,858	5,393	78	2,364	4,154	5,393	6,633	8,423
20	340,763	343,804	-3,041	75	-6,093	-4,289	-3,041	-1,792	12
21	328,776	332,625	-3,849	74	-6,899	-5,097	-3,849	-2,601	-798
22	310,531	313,525	-2,994	73	-6,100	-4,265	-2,994	-1,723	112
23	295,828	298,933	-3,104	72	-6,132	-4,343	-3,104	-1,865	-77
24	283,931	285,082	-1,151	71	-4,200	-2,398	-1,151	97	1,899
	Reference Energy Use (kWh)	Observed Event-Day Energy Use (kWh)	Change in Energy Use (kWh)	Cooling Degree Hours (Base 75 oF)	Uncertainty Adjusted Impact (kWh/hour) - Percentiles				
					10th	30th	50th	70th	90th
Daily	8,282,220	8,113,392	168,828	80.5	n/a	n/a	n/a	n/a	n/a

Figure 4.8 illustrates the patterns of the estimated reference load, observed load, and load impacts (right axis) for the average event day. Figure 4.9 shows a rather tight range of estimated load impacts across events.

Figure 4.8: Hourly Load Impacts for Average CPP Event Day in 2009 – *SDG&E*

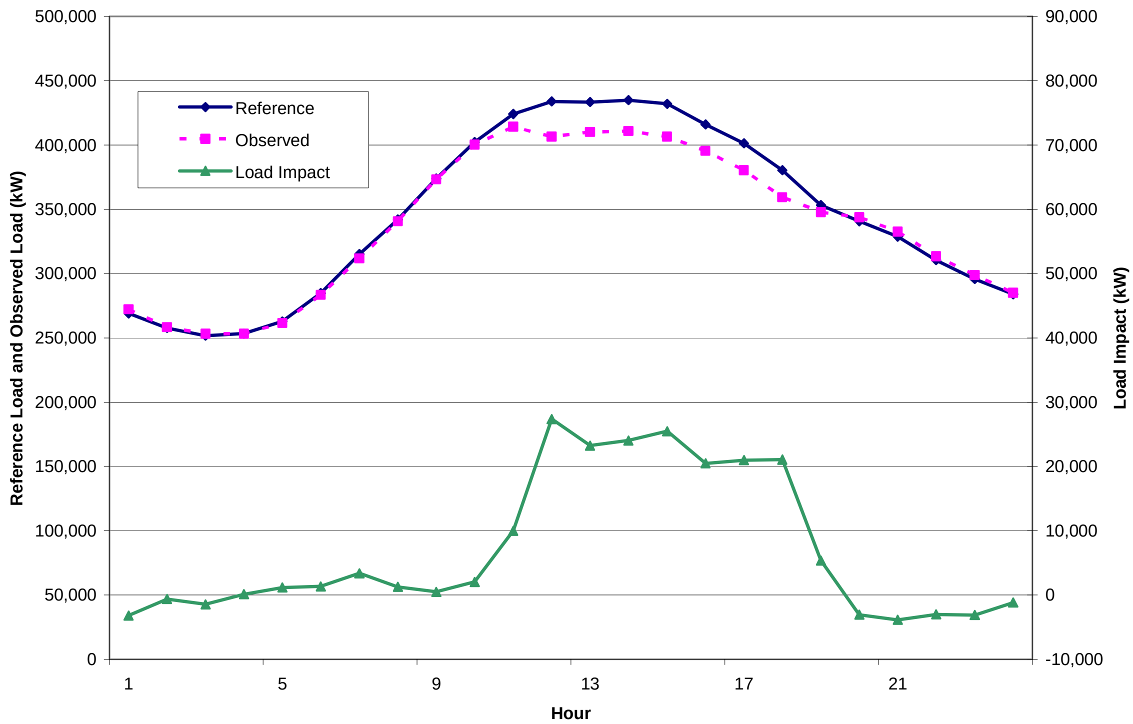
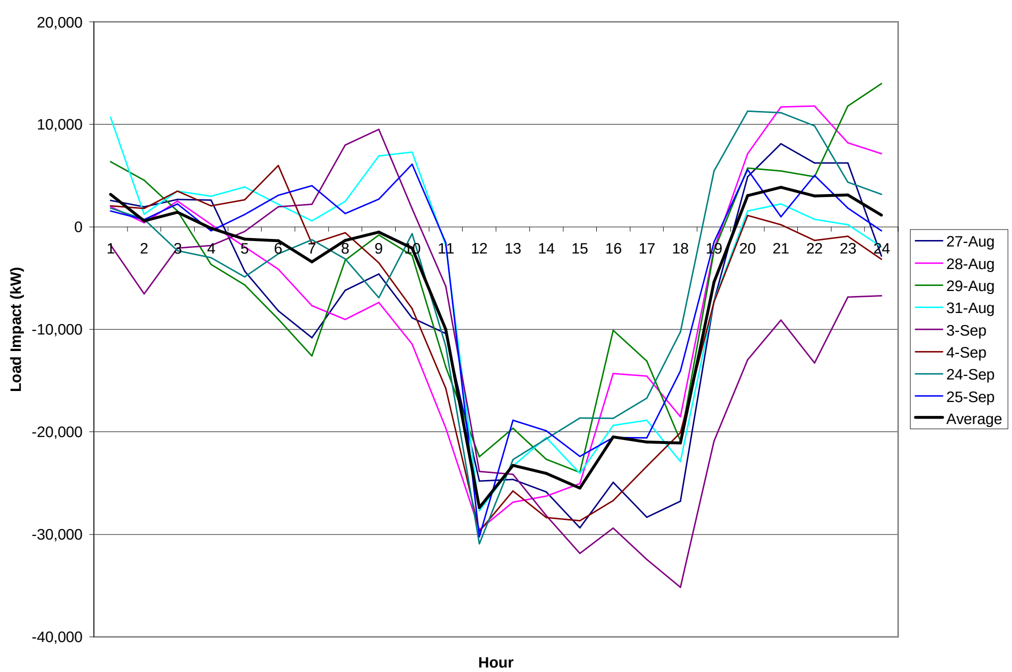


Figure 4.9: Hourly CPP Load Impacts, by Event – *SDG&E*



4.3.3 Additional analyses of SDG&E's default CPP load impacts

The introduction of SDG&E's default CPP rate, along with the occurrence of several CPP events in 2009 (no events were called in 2008), provide the first opportunity to examine two key issues regarding default CPP:

1. Did the load response of customers who had previously enrolled in SDG&E's voluntary CPP rate differ from that of newly defaulted customers?
2. Does the level of capacity reservation appear to be related to the level of a customer's load response?

Developing an understanding of these issues may improve the ability to forecast load impacts over time.

We begin by characterizing the differences between the customer accounts that previously volunteered for CPP and those that were transitioned to default CPP beginning in 2008. Tables 4.12 and 4.13 show differences in the industry group make-up and price responsiveness of the two groups of customer accounts. As shown in the last column, the overall percentage price responsiveness of the previous CPP volunteers was twice that of the newly defaulted customers (10 percent compared to 5 percent). The key factors driving the difference appear to be the higher share of load and greater price responsiveness of the Agriculture, Mining, and Construction; and Wholesale, Transport, and Other Utilities industry groups among the previous volunteers compared to the newly defaulted customers.

Table 4.12: Characteristics of Customers Previously Enrolled in Voluntary CPP

Industry Type	Num. of SAIDs	Sum of Max kW	Sum of Avg. kWh	% of Max kW	Avg. Size (kW)	Ave. Event LI	% LI
1. Agriculture, Mining & Construction	4	6,740	2,122	6%	1,685	980	43%
2. Manufacturing	28	8,495	4,723	7%	303	349	6%
3. Wholesale, Transport, other Utilities	107	33,914	13,406	30%	317	3,196	24%
4. Retail stores	25	10,269	7,277	9%	411	163	2%
5. Offices, Hotels, Health, Services	54	35,822	21,986	32%	663	1,591	6%
6. Schools	56	8,811	3,410	8%	157	0	0%
7. Government, Entertainment, Other Services	23	9,274	5,792	8%	403	596	9%
8. Other/Unclassified	0	0	0	n/a	n/a	0	
TOTAL	297	113,324	58,715	100%	382	6,875	10%

Table 4.13: Characteristics of Customers Newly Defaulted to CPP

Industry Type	Num. of SAIDs	Sum of Max kW	Sum of Avg. kWh	% of Max kW	Avg. Size (kW)	Ave. Event LI	% LI
1. Agriculture, Mining & Construction	15	4,947	2,409	1%	330	95	4%
2. Manufacturing	194	84,202	43,487	17%	434	2,624	5%
3. Wholesale, Transport, other Utilities	159	86,294	31,756	17%	543	3,216	10%
4. Retail stores	103	32,375	19,383	7%	314	1,982	7%
5. Offices, Hotels, Health, Services	427	184,880	112,958	37%	433	6,346	5%
6. Schools	211	45,605	16,826	9%	216	0	0%
7. Government, Entertainment, Other Services	167	58,301	28,400	12%	349	2,156	6%
8. Other/Unclassified	7	857	570	0%	122	-35	-6%
TOTAL	1,283	497,460	255,789	100%	388	16,384	5%

We also present some basic statistics on differences between the two CPP groups in their decisions regarding capacity reservation level and their price responsiveness:

- 18.8 percent of the default CPP customer accounts in 2009 had previously enrolled on the voluntary CPP rate.
- Regarding the *capacity reservation level* (CRL), 41.5 percent of all of the default CPP customer accounts kept the default level of 50 percent.
- Of those service accounts that opted to *change* the capacity reservation level, 81.7 percent selected a capacity reservation level of zero.
- Customers' decision to change their CRL appears to be related to prior participation in the voluntary CPP rate:
    - 80.5 percent of prior voluntary CPP participants changed their capacity reservation level (of which 83 percent selected zero).
    - 53.3 percent of the newly defaulted CPP service accounts changed their capacity reservation level.
- Observed differences in percentage load impacts by type of CPP customer, as shown in Table 4.14, indicate that CPP load response differs between previous volunteers and newly defaulted customers, and by decisions regarding CRL.

Table 4.14: Differences in Percentage Load Impacts by Sub-Groups

Customer Type	Percent of SAIDs	Percent Load Impact
Previously enrolled in voluntary CPP	19%	10%
Newly defaulted to CPP	81%	5%
Kept default CRL (50%)	42%	3%
Changed from default CRL	58%	9%
Changed CRL to zero	48%	9%

The results in Table 4.14 indicate that *overall* percentage load impacts are higher for service accounts that formerly enrolled on the voluntary CPP rate; and for service accounts that elected to change their CRL (most of which selected no capacity reservation). However, these simple average load impact percentages do not control for differences in customer characteristics such as industry group, which have been shown to affect demand responsiveness (as shown in Tables 4.12 and 4.13).

We therefore conducted a statistical analysis to determine the extent to which the overall differences in load impacts may be attributed to factors other than simply prior participation in the voluntary CPP rate or modifying the capacity reservation level. In this regression analysis, the dependent variable for each observation is the estimated percentage load impact for a service account during a particular CPP event (based on the customer-specific regression models).[25] That is, the observations run across customer accounts and events. The data were screened to exclude obviously erroneous load impact estimates, such

[25] Because this method uses customer- and event-level percentage load impacts as the unit of measurement, the results are not directly comparable to the percentage load statistics presented in the bullet points, which are based on aggregated load impacts and reference loads.

as those implying negative implied reference loads.[26] The independent variables include the natural log of the SAID's average hourly usage (as an indicator of size) and indicator (dummy) variables for the following factors:

- Prior participation in the voluntary CPP rate;
- Whether the SAID changed its CRL; and
- If so, whether the level was set to zero kW;
- Participation in TA/TI and AutoDR;
- Industry group, as shown in Table 4.10; and
- Each event date.

Table 4.15 contains the estimated coefficients and standard errors for the key variables of interest, which include previous participation in voluntary CPP and CRL decisions. The coefficients represent the direct influence of these factors after controlling for the effect of industry group. Asterisks are used to indicate estimates that are statistically significantly different from zero with 99 percent confidence. The coefficients may be interpreted as follows:

- Percentage load impacts of SAIDs that previously participated in voluntary CPP were 0.8 percentage points *lower* than those that were newly defaulted onto CPP (controlling for differences in industry group and other factors). However, this difference was not statistically significant.
- Percentage load impacts of SAIDs that changed their CRL were 2.7 percentage points higher than those that retained the default level.
- Percentage load impacts of SAIDs that changed their capacity reservation level to zero kW were an *additional* 2.8 percentage point higher than those that did not. Therefore, SAIDs that changed their capacity reservation level to zero kW had load impacts that were 5.5 percentage points higher that those that retained the default capacity reservation level (2.7 + 2.8 = 5.5 percentage points).

Table 4.15: Regression-Based Estimates of Differences in Percentage Load Impacts by Sub-Groups, after Controlling for Industry Group

Variable	Coefficient	Standard Error
Prior enrollment in voluntary CPP	-0.008	0.0061
Changed the capacity reservation level	0.027*	0.008
Changed the capacity reservation level to zero kW	0.028*	0.008

N = 12,161. R^2 = 0.1087.

The statistical model therefore indicates that the differences in percentage load impacts reflected in the unconditional summary statistics shown in Table 4.14 are affected by differences in the industry group make-up of the different customer categories. After controlling for those other key factors, the "pure" effect of previous participation in

[26] These tend to occur for customers whose normal loads during non-event on-peak periods are very low due to the underlying TOU price structure, such that even small estimated load changes can produce very large percentage load impacts. Furthermore, if the estimated load impact is positive (a load increase rather than load reduction), then the implied reference load may become negative.

voluntary CPP and CRL decisions are seen to be substantially smaller. For example, after controlling for differences in industry group, and for choice of CRL level, there was no longer a significant difference in percentage load impacts for previous volunteers and newly defaulted customer accounts. In contrast, the greater load response of customer accounts that changed their CRL from the default level, particularly when they changed it to zero, compared to those that left it at the default level was confirmed by the statistical analysis. However, the incremental effect was smaller after controlling for differences in industry group.

4.4 Effect of TA/TI and AutoDR on Load Impacts

This section describes the *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 so that they can identify ways to participate in DR. The TI portion of the program then provides incentive payments for the installation of equipment or control software supporting DR.

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

For each utility and incentive program, we present two tables of information. The first table contains the overall load impact provided by the service accounts on TA/TI or AutoDR. The second table contains a comparison of the percentage load impacts achieved by TA/TI or AutoDR SAIDs to those of a relevant group of non-participating service accounts. In this table, each row of data shows the outcome for SAIDs within a 6-digit NAICS code or 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 compare at a higher level of industry aggregation, such as 2-digit SIC codes or 3-digit NAICS codes. In some cases, the sample of service accounts does not contain any reasonable basis of comparison for the 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 lack of complete information. For example, we rarely observe "before and after" load responses for the same service account, because the TA/TI and AutoDR audits and installations typically took place prior to any events in 2009. In addition, enabling technology may be used by some SAIDs that did not participate in AutoDR or TA/TI. Therefore, we cannot even be certain that when we compare TA/TI and non-TA/TI accounts we are actually measuring a "with and without" technology difference. However, given the available data, we believe that the comparisons made in this section are informative and the most relevant ones to provide.

The sub-sections below present the results for each of the utilities.

PG&E

PG&E's CPP program included participants in both the AutoDR and TA/TI programs. Table 4.16 shows the event-specific load impacts for the AutoDR participants. On average, the AutoDR customers provided 1.6 MW of load reduction, or 6 percent of their reference load.

Table 4.16: Summary of AutoDR Load Impacts by Event, *PG&E*

Event Date	Number of SAIDs	Estimated Reference Load (kW)	Observed Load (kW)	Estimated Load Impact (kW)	% Load Impact
6/29/2009	34	26,822	24,922	1,901	7.1%
6/30/2009	34	25,103	23,980	1,123	4.5%
7/13/2009	34	25,781	24,262	1,520	5.9%
7/14/2009	34	28,371	26,596	1,775	6.3%
7/16/2009	34	25,088	24,059	1,030	4.1%
7/21/2009	34	24,060	22,441	1,619	6.7%
7/27/2009	34	24,912	24,369	543	2.2%
8/10/2009	34	28,584	26,801	1,783	6.2%
8/11/2009	34	26,245	24,368	1,878	7.2%
8/18/2009	34	25,693	23,920	1,773	6.9%
8/27/2009	34	27,630	25,638	1,992	7.2%
8/28/2009	34	30,039	27,804	2,235	7.4%
Average	**34**	**26,527**	**24,930**	**1,598**	**6.0%**

Table 4.17 shows that the percentage load impact vary considerably across 6-digit NAICS industry classifications. The highest percentage load impacts are provided by the Water Supply and Irrigation Systems customers (NAICS code 221310) and the Frozen Specialty Food Manufacturing customers (NAICS code 311412).

Table 4.17: Incremental AutoDR Load Impacts, *PG&E*

NAICS Code	NAICS Description	Basis of Comparison	Percentage Load Impact		Number of Events	
			No AutoDR	AutoDR	No AutoDR	AutoDR
221310	Water Supply and Irrigation Systems	6-digit NAICS	-5.0%	25.5%	84	12
311412	Frozen Specialty Food Manufacturing	6-digit NAICS	21.3%	20.4%	48	24
334419	Other Electronic Component Manufacturing	6-digit NAICS	-1.3%	1.2%	36	108
442110	Furniture Stores	No Comparables	n/a	n/a	n/a	n/a
452112	Discount Department Stores	2-digit NAICS	16.2%	14.8%	360	36
511210	Software Publishers	6-digit NAICS	-1.8%	3.5%	36	24
531123	Lessors of Nonresidential Buildings	6-digit NAICS	0.3%	8.2%	180	12
541710	Research and Development in Biotechnology	6-digit NAICS	-0.4%	8.5%	156	48
551114	Corporate Offices	6-digit NAICS	-0.4%	5.6%	228	24
611112	Elementary and Secondary Schools	6-digit NAICS	0.0%	0.0%	924	12
611114	Elementary and Secondary Schools	6-digit NAICS	0.0%	0.0%	288	12
624310	Vocational Rehabilitation Services	2-digit NAICS	0.6%	2.2%	96	12
712110	Museums	6-digit NAICS	0.8%	15.5%	12	12
921190	Other General Government Support	6-digit NAICS	2.6%	6.0%	60	36
922120 & 922130	Police Protection, Legal Counsel and Prosecution	4-digit NAICS	-1.8%	8.1%	12	24
922140	Correctional Institutions	6-digit NAICS	-0.6%	2.0%	24	24

The incremental effect of AutoDR, expressed as the difference between the percentage load impacts for AutoDR and non-AutoDR customers within each row of Table 4.14, ranges from 30.5 percentage points to -1.4 percentage points. The simple average of the incremental AutoDR load impacts across the rows of the table is 6.1 percentage points.

Table 4.18 shows the event-specific load impacts for TA/TI service accounts. On average, these service accounts provided 149 kW of load response, or 2.3 percent of their reference load.[27]

[27] Upon examination of the metered load data, we zeroed out the estimated load impacts for one of the seven service accounts contained in Tables 4.18 and 4.19. It was clear that the customer's peak-period usage did not differ between event and non-event days. The fact that this customer had "high-load" and "low-load" days in

Table 4.18: Summary of TA/TI Load Impacts by Event, *PG&E*

Event Date	Number of SAIDs	Estimated Reference Load (kW)	Observed Load (kW)	Estimated Load Impact (kW)	% Load Impact
6/29/2009	7	6,610	6,565	45	0.7%
6/30/2009	7	6,557	6,568	-11	-0.2%
7/13/2009	7	6,587	6,898	-311	-4.7%
7/14/2009	7	6,879	6,725	154	2.2%
7/16/2009	7	6,466	6,048	418	6.5%
7/21/2009	7	6,264	6,049	214	3.4%
7/27/2009	7	6,360	6,305	55	0.9%
8/10/2009	7	6,617	6,782	-165	-2.5%
8/11/2009	7	6,231	6,155	76	1.2%
8/18/2009	7	6,442	6,114	328	5.1%
8/27/2009	7	6,548	6,084	464	7.1%
8/28/2009	7	6,825	6,300	525	7.7%
Average	**7**	**6,532**	**6,383**	**149**	**2.3%**

Table 4.19 provides little evidence that TA/TI has provided incremental load impacts. Two industry groups (334419, Other Electronic Component Manufacturing; and 531123, Lessors of Nonresidential Buildings) provide some evidence of modest improvements in demand response, with increases in load impacts of 4.2 and 1.7 percentage points, respectively.

Table 4.19: Incremental TA/TI Load Impacts, *PG&E*

NAICS Code	NAICS Description	Basis of Comparison	Percentage Load Impact		Number of Events	
			No TA/TI	TA/TI	No TA/TI	TA/TI
326291	Rubber Product Manufacturing	3-digit NAICS	3.8%	1.6%	48	12
332911	Industrial Valve Manufacturing	3-digit NAICS	45.9%	0.0%	60	12
334419	Other Electronic Component Manufacturing	6-digit NAICS	-1.3%	2.9%	36	36
531123	Lessors of Nonresidential Buildings	6-digit NAICS	0.3%	2.0%	180	12
721110	Hotels and Motels	6-digit NAICS	3.0%	-0.5%	24	12

PG&E contacted some of the non-responsive TA/TI customers in an attempt to understand the apparent lack of performance during CPP event days. The customers responded that they were confused by the fact that they were enrolled in multiple DR programs (*e.g.*, DBP and CPP), and they apparently did not understand their performance duties / opportunities on event days. Based on this anecdotal evidence, it appears that customers may require

an unpredictable pattern (unrelated to CPP event days) prevented the econometric model from estimating the correct event-day load impacts.

additional education and follow-up from utility representatives in order to take full advantage of the installed technology.

SCE

Table 4.20 shows the event-specific load impacts for SCE's AutoDR participants. On average, these customers provided 1.9 MW of load reduction, or 28 percent of their reference load.

Table 4.21 shows differences in percentage load impact across 4-digit SIC industry classifications. The highest percentage load impacts are provided by the Storage Batteries customers (SIC code 3691). The difference in the percentage load impacts for SAIDs with and without AutoDR is large, averaging 20.6 percentage points across our comparisons. Note that we could not find a reasonable comparison group for one of the industry groups, SIC 1611 (Highway and Street Construction).

Table 4.20: Summary of AutoDR Load Impacts by Event, *SCE*

Event Date	Number of SAIDs	Estimated Reference Load (kW)	Observed Load (kW)	Estimated Load Impact (kW)	% Load Impact
6/18/2009	16	4,127	3,488	639	15.5%
7/15/2009	16	5,151	4,062	1,089	21.1%
7/17/2009	16	4,883	3,748	1,135	23.2%
7/20/2009	17	7,363	4,953	2,410	32.7%
7/22/2009	17	7,672	5,142	2,529	33.0%
7/27/2009	17	7,001	4,907	2,094	29.9%
7/28/2009	17	6,866	6,164	701	10.2%
8/20/2009	17	6,360	4,261	2,099	33.0%
8/27/2009	17	7,845	5,548	2,297	29.3%
8/28/2009	17	7,886	5,056	2,829	35.9%
9/1/2009	17	7,311	5,263	2,048	28.0%
9/2/2009	17	8,100	5,436	2,663	32.9%
Average	**17**	**6,713**	**4,836**	**1,878**	**28.0%**

Table 4.21: Incremental AutoDR Load Impacts, *SCE*

SIC Code	SIC Description	Basis of Comparison	Percentage Load Impact		Number of Events	
			No AutoDR	AutoDR	No AutoDR	AutoDR
1611	Highway and Street Construction	No Comparables	n/a	n/a	n/a	n/a
2834	Pharmaceutical Preparations	2-digit SIC	14.2%	18.9%	168	12
3069	Fabricated Rubber Products	4-digit SIC	9.9%	27.3%	36	12
3691	Storage Batteries	2-digit SIC	26.3%	65.3%	91	9
5211	Lumber Dealers	2-digit SIC	12.7%	40.9%	12	12
6512	Operators of Non-Residential Buildings	4-digit SIC	1.0%	14.8%	72	132

Tables 4.22 and 4.23 contain the load impacts by event for TA/TI customers. One service account with a high level of load impacts moved from TA/TI to AutoDR during the program year. In the absence of that customer (beginning with the July 20th event), TA/TI load impacts are modest in size (60 kW), but more substantial as a percentage of the reference load (15.4 percent). The SIC group with the largest difference between load impacts with and without TA/TI represents the SAIDs that switched from AutoDR. Therefore, Tables 4.21 and 4.23 reflect similarly large incremental load impacts for SIC 3691.

Table 4.22: Summary of TA/TI Load Impacts by Event, *SCE*

Event Date	Number of SAIDs	Estimated Reference Load (kW)	Observed Load (kW)	Estimated Load Impact (kW)	% Load Impact
6/18/2009	2	2,644	813	1,830	69.2%
7/15/2009	2	2,660	831	1,829	68.8%
7/17/2009	2	2,857	1,351	1,506	52.7%
7/20/2009	1	398	372	25	6.3%
7/22/2009	1	384	156	227	59.3%
7/27/2009	1	415	375	41	9.8%
7/28/2009	1	430	411	18	4.3%
8/20/2009	1	433	373	59	13.6%
8/27/2009	1	370	340	30	8.2%
8/28/2009	1	336	319	16	4.8%
9/1/2009	1	405	292	113	27.9%
9/2/2009	1	327	312	15	4.5%
Average	**1**	**971**	**496**	**476**	**49.0%**

Table 4.23: Incremental TA/TI Load Impacts, *SCE*

SIC Code	SIC Description	Basis of Comparison	Percentage Load Impact		Number of Events	
			No TA/TI	TA/TI	No TA/TI	TA/TI
3398	Metal Heat Treating	4-digit SIC	14.7%	14.4%	36	12
3691	Storage Batteries	2-digit SIC	26.3%	73.2%	91	3

SDG&E

SDG&E's CPP program included participants in both the AutoDR and TA/TI programs. Table 4.24 shows the event-specific load impacts for the AutoDR participants. On average, the AutoDR customers provided 1.4 MW of load reduction, or 17 percent of their reference load.

Table 4.25 shows differences in percentage load impacts across 6-digit NAICS industry classifications. The highest percentage load impacts (in terms of the level and estimated incremental impact) are provided by the Sporting Goods Store customers (NAICS code 452111). At the other extreme, the AutoDR customers in the Casino Hotels group (NAICS code 721120) provided much *lower* percentage load impacts than did the comparable non-AutoDR customers.

Table 4.24: Summary of AutoDR Load Impacts by Event, *SDG&E*

Event Date	Number of SAIDs	Estimated Reference Load (kW)	Observed Load (kW)	Estimated Load Impact (kW)	% Load Impact
8/27/2009	11	7,501	5,649	1,851	24.7%
8/28/2009	12	8,309	6,619	1,690	20.3%
8/29/2009	12	8,601	6,943	1,658	19.3%
8/31/2009	12	7,652	6,528	1,124	14.7%
9/3/2009	12	8,263	6,736	1,527	18.5%
9/4/2009	12	8,045	6,823	1,222	15.2%
9/24/2009	12	7,656	6,197	1,459	19.1%
9/25/2009	12	7,569	7,135	434	5.7%
Average	12	7,949	6,579	1,371	17.2%

Table 4.25: Incremental AutoDR Load Impacts by Comparison Group, *SDG&E*

NAICS Code	NAICS Description	Basis of Comparison	Percentage Load Impact		Number of Events	
			No AutoDR	AutoDR	No AutoDR	AutoDR
452111	Department Stores	6-digit NAICS	2.3%	25.6%	80	48
512131	Motion Picture Theaters	6-digit NAICS	1.5%	3.5%	136	8
721110	Hotels and Motels	6-digit NAICS	4.7%	2.5%	376	32
721120	Casino Hotels	6-digit NAICS	24.3%	3.4%	17	7

Table 4.26 shows that SDG&E's TA/TI customers provided an average of 714 kW of demand response for the average event, or 13.4 percent of their reference load. The highest overall and incremental percentage load impact, shown in Table 4.27) was provided by the Sporting Goods Store customers (NAICS code 452111).

Table 4.26: Summary of TA/TI Load Impacts by Event, *SDG&E*

Event Date	Number of SAIDs	Estimated Reference Load (kW)	Observed Load (kW)	Estimated Load Impact (kW)	% Load Impact
8/27/2009	13	5,090	4,332	758	14.9%
8/28/2009	13	5,429	4,432	998	18.4%
8/29/2009	13	4,903	4,449	454	9.3%
8/31/2009	13	5,260	4,876	383	7.3%
9/3/2009	13	5,593	4,909	683	12.2%
9/4/2009	13	5,756	4,744	1,012	17.6%
9/24/2009	13	5,176	4,393	783	15.1%
9/25/2009	13	5,304	4,662	641	12.1%
Average	13	5,314	4,600	714	13.4%

Table 4.27: Incremental TA/TI Load Impacts, *SDG&E*

NAICS Code	NAICS Description	Basis of Comparison	Percentage Load Impact		Number of Events	
			No TA/TI	TA/TI	No TA/TI	TA/TI
452111	Department Stores	6-digit NAICS	2.3%	29.6%	80	64
531121	Lessors of Nonresidential Building	6-digit NAICS	19.9%	15.7%	120	16
541710	Research and Development in Biotechnology	6-digit NAICS	2.0%	11.4%	464	24

4.5 Distributions of CPP load impacts

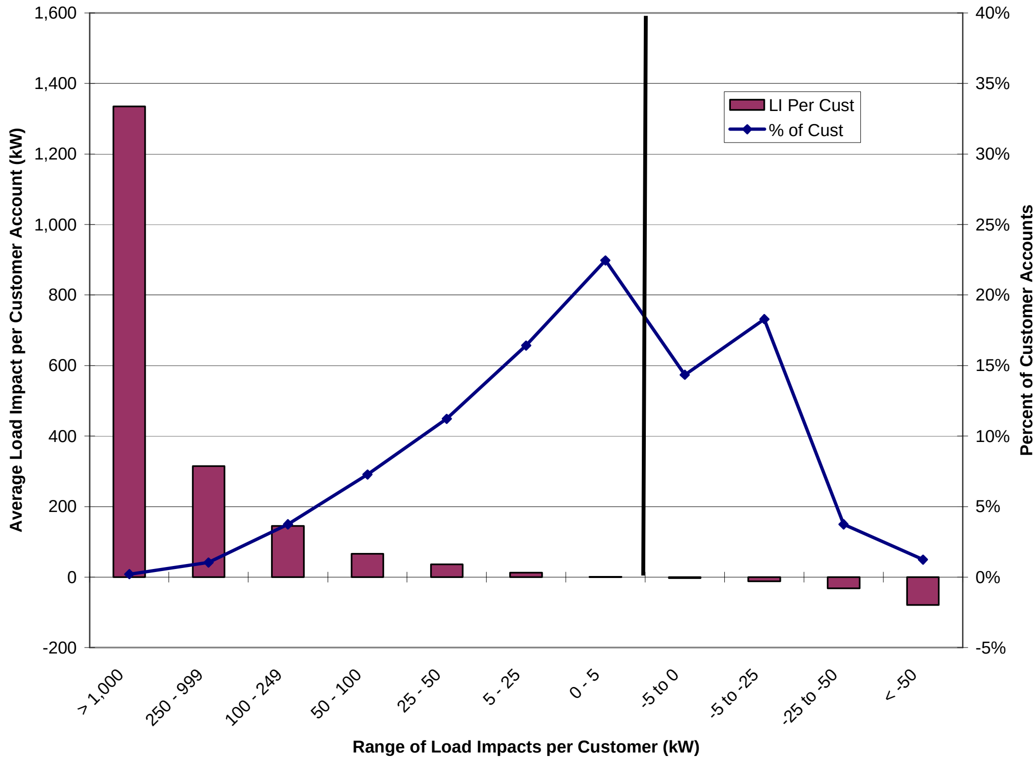
In addition to calculating aggregated load impacts, the estimation of customer-specific regression equations and load impacts provides the capability to examine the distributions of CPP load impacts across customer accounts. Below, we provide figures for each utility which illustrate ranges of *average hourly load impacts per customer* and the *percent of customer accounts* that achieved those ranges of load impacts. Figures 4.10 through 4.12 show results for PG&E, SCE and SDG&E respectively.

In general, the three distributions of estimated load impacts have quite similar characteristics. They are skewed to the left, pointing to the relatively large load impacts provided by only a few customers, and the correspondingly large share of total load impacts that are provided by a relatively small fraction of customer accounts.[28] The SCE curve showing the percent of customers in each range of load impacts is somewhat "fatter" than the other two, and skewed more to the left, implying a relatively greater share of price-

[28] The relatively small numbers of estimated negative load impact values in each of the distributions, which imply load *increases* during event hours, are typical of such distributions. These values are frequently not statistically significant, and generally occur in cases where customers' loads vary considerably from day to day for reasons that cannot be explained by the variables in the regression models.

responsive customers than the other two utilities. SCE also currently has the smallest enrollment and largest average percentage load impact of the three utilities.[29]

Figure 4.10: Distribution of CPP Load Impacts – *PG&E*



[29] Approximately 100, 160 and 270 customer accounts in the Schools industry group at SCE, PG&E and SDG&E respectively were excluded from the distributions because they were judged to provide no event-day load impacts. Adding them to the distribution would have the effect of raising the percentages of customer accounts near the center (zero load impacts) of the distributions.

Figure 4.11: Distribution of CPP Load Impacts – *SCE*

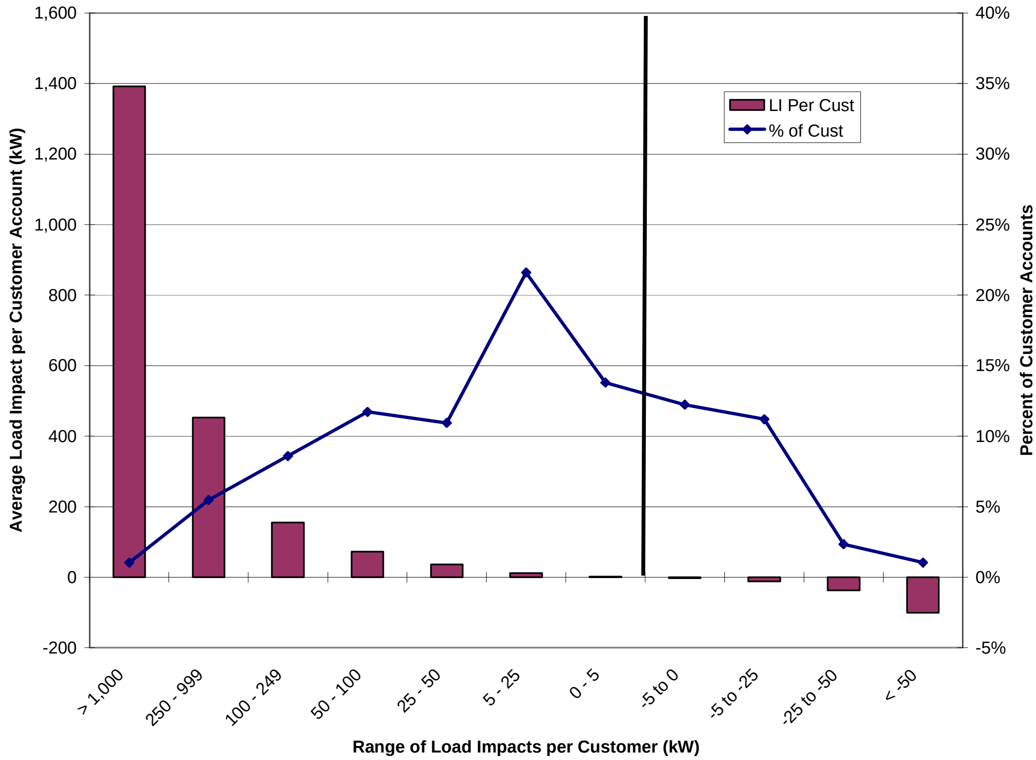


Figure 4.12: Distribution of CPP Load Impacts – *SDG&E*

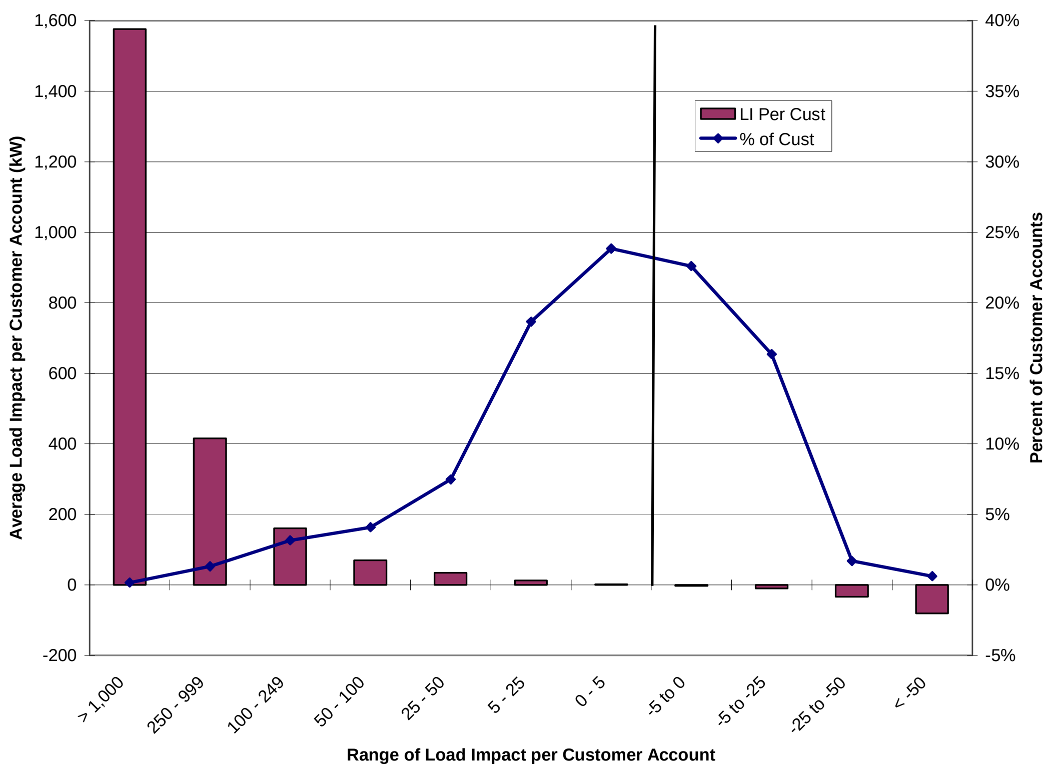


Table 4.28 summarizes some of the key indicators of the distributions shown in the three figures above. The first column reports the percentage of customers who were estimated to provide load impacts of at least 5 kW. The 59 percent value for SCE (compared to 35 and 40 percent for SDG&E and PG&E) is consistent with the findings of greater price responsiveness among SCE's CPP customers.[30] The second and third columns are related. The second column shows the cumulative percentages of customer accounts that provided the share of total program load impacts shown in the third column. As shown in the table, from 4.6 to 6.5 percent of the customers provide 61 to 72 percent of the total program load impacts across the three utilities.

Table 4.28: Indicators of CPP Customer Price-Responsiveness

Utility	Percent of Customers with Estimated LI > 5 kW	Cumulative % of Customers that Provide…	the Following % of Total Load Impacts
PG&E	40%	5.0%	64%
SCE	59%	6.5%	61%
SDG&E	35%	4.6%	72%

5. Ex Ante Load Impacts

This section documents the preparation of ex ante forecasts for 2010 to 2020 of reference loads and load impacts for the default non-residential CPP programs (now referred to as Peak Day Pricing, or PDP at PG&E) offered by PG&E, SCE, and SDG&E.

The forecasts of load impacts were developed in the following four steps:

1. Estimates of reference loads, on a per-customer basis, were developed based on modified versions of the ex post load impact regressions that were described in Section 4. Reference loads were simulated 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).
2. Percentage load impacts or price elasticities were calculated based on the ex post load impact evaluation results.
3. The load impacts were applied to the simulated reference loads. The load impacts were based on either ex post percentage load impacts (SDG&E) or elasticities derived from the ex post results that were combined with forecast CPP/PDP rates to calculate percentage load impacts.
4. The reference loads and load impacts were combined with program enrollment forecasts from the utilities to develop alternative forecasts of load impacts.

[30] Note that most of SCE's voluntary CPP customers selected the rate option that has the highest CPP price (in return for a discounted summer peak demand charge), and have historically included large and flexible manufacturing and water utility customers who have the ability and financial incentive to reduce load during CPP event hours.

Forecasts are developed and reported at the program level and by CAISO *Local Capacity Area*, as well as by the event day-types described in Section 5.1 below. For PG&E, enrollment forecasts were provided through a separate contract with The Brattle Group. 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 must be reported by the following factors (in addition to the program level and LCA factors 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

Customer accounts were assigned to one of three size groups, eight industry types (defined in Section 2.2), and relevant LCAs based on information provided by the utilities. The three size groups were the following:

- Small – maximum demand less than 20 kW (only PG&E provided enrollment forecasts for this size group);
- Medium – maximum demand between 20 and 200 kW (PG&E and SDG&E provided enrollment forecasts for this size group);
- Large – maximum demand greater than 200 kW.

The specific definition of "maximum demand" differed by utility. For PG&E and SCE, the size definition was based on the tariff on which the customer is served. For example, a tariff may require that a customer's monthly peak demand exceeds 20kW for three out of the previous twelve months. For SDG&E, the size definition was based on each customer's maximum summer on-peak demand.

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*

Historically, non-residential CPP has been a voluntary program. In 2008, SDG&E transitioned to a default CPP rate. SCE began transitioning customers to default CPP in the fall of 2009, and PG&E is beginning a similar transition in 2010. These transitions have produced the following two analytical issues to resolve for purposes of developing ex ante forecasts.

First, we needed to determine appropriate sources of *load impact* data. Only SDG&E has experienced CPP events and observed customer load impacts under a default rate. Thus, the ex post evaluation of CPP at SDG&E described in Section 4 provides a useful source of information regarding the price responsiveness of default CPP customers of different types.

Developing load impacts for default CPP at SCE was complicated by the fact that its voluntary CPP program has been relatively small until 2009, with enrollees who tended to be larger and more price responsive than at the other two utilities (enrollment expanded to 485 customer accounts during 2009). The nature of the load profiles and magnitude of the estimated ex post load impacts for historical voluntary CPP suggest that these customers are not fully representative of the customers that would be expected to remain on the default CPP program in the future. As a result, in the ex ante analysis, we developed load impacts based on price elasticities estimated under SDG&E's default CPP rate for comparable types of customers, and applied them to SCE's planned default CPP rate to produce percentage load impacts.

PG&E's voluntary CPP rate has seen a relatively large and diverse set of enrolled customers (650 customer accounts in 2009). As a result, we based price elasticity values in the ex ante analysis on the results of the 2009 ex post load impact evaluation.

The historical voluntary CPP programs generally did not include customers with demands less than 200 kW. However, estimated load impacts for future default CPP programs were needed for small and medium-size customers. An appropriate source of price responsiveness values is the Statewide Pricing Pilot (SPP). In the 2008 ex ante evaluation of CPP, Freeman, Sullivan & Company developed price elasticities for small and medium customers from the SPP results. Those results were used again in this ex ante evaluation.

In addition to defining the sources of the load impacts, we needed to define the sources of *reference loads*, since the types of customers that will participate in default CPP in the future will differ from those that have enrolled in voluntary CPP historically. Only SDG&E has experienced load profiles that are representative of large (> 200 kW) customers who remain on a default CPP rate. We based SDG&E's reference loads in the ex ante evaluation for that size group on the customer accounts enrolled in default CPP during 2009.[31]

For SCE and PG&E, we used the customers enrolled in their 2009 voluntary CPP programs as the basis for the ex ante CPP/PDP load profiles for large customers greater than 200 kW. The reference loads were scaled to account for expected differences in the *level* of the forecast reference loads between the historical voluntary and future default programs. For SCE, the scaling factor was the average summer maximum demand. For PG&E, the scaling factor was annual energy consumption. For PG&E, separate scaling factors were developed for each size group / industry group / LCA cell.

For customers of size less than 200 kW, SDG&E developed load profiles by industry group for medium customers.[32] PG&E's load profiles for small and medium customers were developed from the load research sample underlying the dynamic load profiles.

2. *Estimate ex ante regression models and simulate per-customer reference loads*
For each utility, we first re-estimated regression equations for each enrolled CPP customer account, using data for 2009. These equations were then used to simulate reference loads by customer type under the various scenarios required by the Protocols (*e.g.*, the typical event day in a 1-in-2 weather year).

The re-estimated regression equations were similar in design to the ex post load impact equations described in Section 3.1, differing primarily in two ways. First, the event variables were modified from the version that produced ex-post estimates of 24 hourly load impact values for *each* event, to a version that produces estimates of *average hourly event-period* load impacts across all events. Second, the ex ante models excluded 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 were modified from the definitions used in the 2009 report. Basically, the utilities moved away from using weather for a particular year, to a process for identifying weather extremes on a monthly basis.

[31] This group also includes some customers with maximum demands under 200 kW.
[32] Small customers were not included in the analysis due to uncertainty about dates of meter installation and eligibility.

For PG&E and SCE, we developed per-customer load profiles for all interactions of size group, industry group, and LCA. Because of small sample sizes, we pooled all of the customer load profiles across LCAs to arrive at a set of simulation coefficients that was common to each size and industry group combination. Differences in the load profiles across LCAs were solely due to differences in the weather conditions used in the simulations. This was not an issue for SDG&E because its entire service territory is comprised of a single LCA.

3. *Calculate forecast percentage load impacts by cell*

Using the historical ex post load impacts described in step 1, we calculated percentage load impacts for a typical event for each industry group. These ex-post percentage load impacts were then converted to ex-ante load impact estimates using approaches that differed somewhat between utilities, as follows.

> For SDG&E, the ex-post percentage load impacts for large customers were used directly, because they were based on the form of default CPP expected to continue in the future. Since only total enrollment was forecast, an estimated overall percentage load impact was calculated, to be applied to an aggregate reference load profile. For medium-size customers, enrollment forecasts were provided by industry group. Elasticities from SPP for these industry groups were used to calculate percentage load impacts.
>
> For SCE, we used the estimates of typical event day load impacts from the 2009 SDG&E default CPP ex-post evaluation data to derive equivalent *elasticities of substitution* and daily usage elasticities, by industry group. The estimated elasticities were then applied to SCE's anticipated default CPP rates to produce percentage load impacts by industry type. The estimated elasticities of substitution and daily price elasticities are shown in Table 5.1.[33]

Table 5.1: Elasticities of Substitution from SDG&E Default CPP Customers

	Elasticity of Substitution	Daily Price Elasticity
1. Agriculture, Mining & Construction	0.139	-0.070
2. Manufacturing	0.025	-0.018
3. Wholesale, Transport, other Utilities	0.082	-0.031
4. Retail stores	0.033	-0.016
5. Offices, Hotels, Health, Services	0.023	-0.015
6. Schools	0.000	0.000
7. Entertainment, Other Services and Gov't	0.032	-0.022

[33] On a technical note, by convention in economic demand theory, elasticities of substitution are defined as the *negative* of the ratio of the percentage change in a *quantity* ratio (*e.g.*, the ratio of peak to off-peak load on CPP and non-CPP days) to the percentage change in the corresponding *price* ratio (*e.g.*, the ratio of the peak to off-peak price on CPP and non-CPP days), and thus take on *positive* values. Occasionally, as in the SPP study, elasticities of substitution are shown with negative signs, perhaps by analogy with traditional own-price elasticities, which normally take on negative values.

For PG&E, we based the ex-ante percentage load impacts on a process analogous to that used for SCE, but using PG&E's own ex-post data. The process involved three steps – 1) use the ex-post percentage load impacts by industry type; 2) convert those percentage load impacts to price elasticities using the price ratios in PG&E's voluntary CPP rate; and 3) applying PG&E's anticipated PDP rates to the calculated price elasticities to produce percentage load impacts under PDP. The approach followed the steps that were used in the 2008 ex-ante evaluation. Specifically, we calculated *own-price elasticity* values for the CPP event hours based on *percentage load impacts* for the typical event day from the ex post evaluation, and *percentage price changes* based on the voluntary CPP tariff (*e.g.*, by comparing the price during CPP event hours on event and non-event days). In this process, demand charges were converted to "effective energy charges" by dividing the demand charge by the number of hours over which the demand may be established.

We then applied the resulting critical-hour price elasticities to the price changes implied by the forecast PDP rates to determine percentage load changes during event hours. The scenarios of load impacts required for the uncertainty-adjusted load impacts were generated from the corresponding scenarios in the ex post load impacts. That is, scenario-specific price elasticities were developed from the 10^{th}, 30^{th}, 50^{th}, 70^{th}, and 90^{th} percentile load changes estimated for the historical program year.

We also simulated load changes in the non-critical hours of event days by estimating the percentage of the load reduced during event hours that was shifted to non-event hours on the typical event day. This percentage was then applied uniformly across all customer groups.[34]

Customers under 200 kW

Because no ex post load impact evaluations exist for medium (20 to 200 kW) and small (under 20 kW) CPP customers, price elasticity values were taken from different sources for these customers. The primary source of the price elasticities was the Statewide Pricing Pilot, in which small and medium C&I customers were exposed to CPP rates, with price elasticities estimated from the resulting load data. From this study, we used the critical day substitution elasticities and the critical day daily elasticities. The former elasticity is used to simulate the change in the ratio of usage between event and non-event hours on critical days. The latter elasticity is used to simulate the change in total energy usage on the critical event day. Table 5.2 shows the elasticity values used in the study. Notice that small C&I customers did not exhibit any demand response in the absence of enabling technology. For PG&E, the load impacts for the under 200 kW customers combine the load impacts associated with moving from a flat to time-of-use rate with the event-day PDP load impacts.

For PG&E's under 200 kW customers, we simulated two sets of per-customer load impacts: one set for customers who are only on PDP; and one set for customers who are on both

[34] Group-specific percentages did not appear to be reliable.

PDP and SmartAC. The dually enrolled customers have larger percentage load impacts, based on the "with enabling technology" elasticities estimated in the SPP.

Table 5.2: Price Elasticities Adapted from the Statewide Pricing Pilot, Customers Under 200 kW

Elasticity Type		Small C&I	Medium C&I
No Enabling Technology	Critical Day Substitution	0.000	0.041
	Critical Day Daily	0.000	-0.025
Enabling Technology	Critical Day Substitution	0.089	0.082
	Critical Day Daily	-0.025	-0.025

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

5. *Apply forecast enrollments to produce program-level load impacts*.
Load impacts at the program level and by LCA were produced by applying the results in the previous step to the enrollment forecasts provided by the utilities. 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. The enrollment forecasts are described in the following section.

5.3 Enrollment Forecasts

This section summarizes the ex ante enrollment forecasts. The following section summarizes reference loads and load impacts.

5.3.1 PG&E

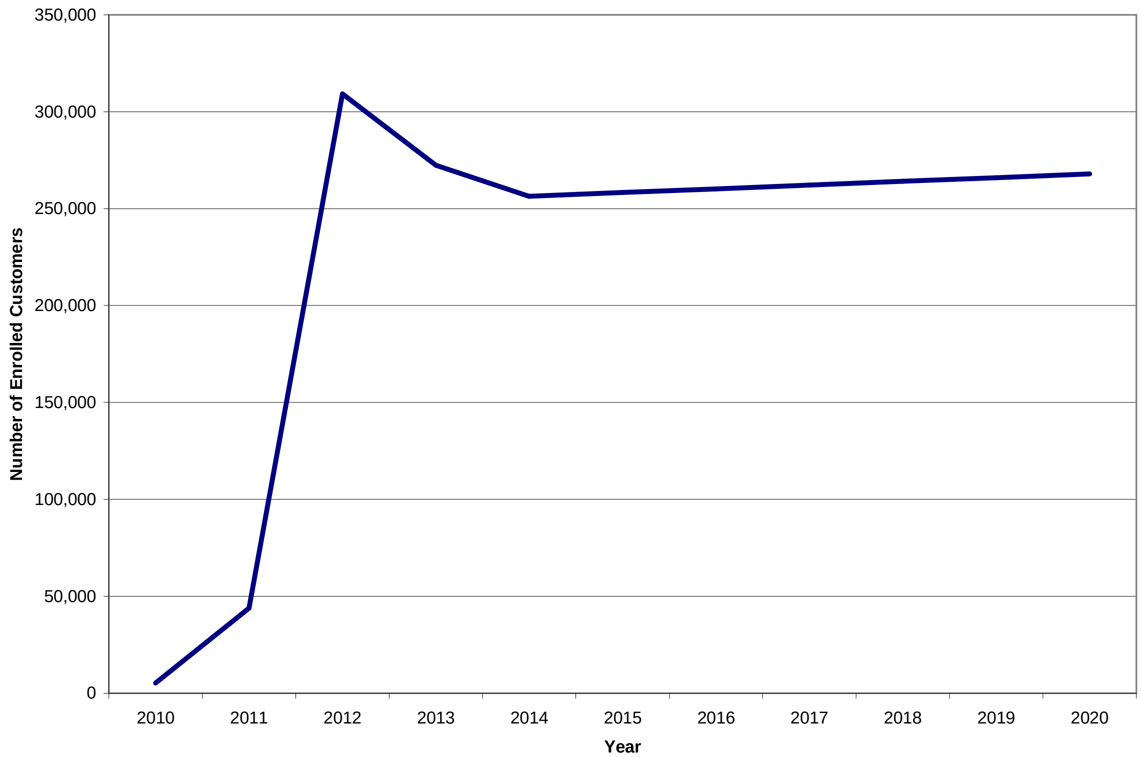
The Brattle Group estimated PDP enrollments for PG&E, and has provided a separate report summarizing the methods and results of their study. Figure 5.1 illustrates the number of customers forecasted to be enrolled in PDP by year. Enrollments rise rapidly through 2012 as more customers become eligible for the tariff, and then fall as some customers are forecast to opt-out to TOU. Enrollments then remain fairly constant after 2014.

PG&E's small and medium customers (under 200 kW) have a choice between four variants of PDP, choosing from 4-hour and 6-hour event windows (with the 6-hour window having 2/3 the event-hour price of the 4-hour variant) and whether events can be called on consecutive days (customers who cannot be called on consecutive days receive 50 percent of the credits in non-event hours). The share of customers in each option was fixed across forecast years, as follows:

- 60 percent of the customers on the 4-hour event window, consecutive day variant (which is the default);
- 20 percent on the 4-hour event window, non-consecutive day variant; and
- 10 percent of the customers on each of the 6-hour event window variants.

When developing the database of per-customer load impacts, we assumed that customers on the non-consecutive variants of the program provided half of their event-day load impacts. This is equivalent to assuming that half of these customers are called for each event.

Figure 5.1: PG&E PDP Enrolled Customers by Year



5.3.2 SCE

SCE provided the forecast number of enrolled customers for each industry group/LCA combination for the first three years of the default CPP program, after which they assume that enrollments remain stable. SCE based its enrollment forecast on forecasts of opt-out rates by industry group. Overall, they assume that the opt-out rate begins at 20 percent in the first year, increases to 53 percent in the second year, and levels off at 63 percent in the third year and beyond. The third-year opt-out rate is highest in the Retail Stores and Offices, Hotels, Health, and Services industry groups (at over 80 percent) and is lowest for Schools (29 percent). Table 5.3 shows the forecasts of enrolled customer accounts by industry group for the first three years of the program. Note that SCE's default CPP rate only applies to customers over 200 kW.

Table 5.3: Enrollment Forecasts for Default CPP – SCE

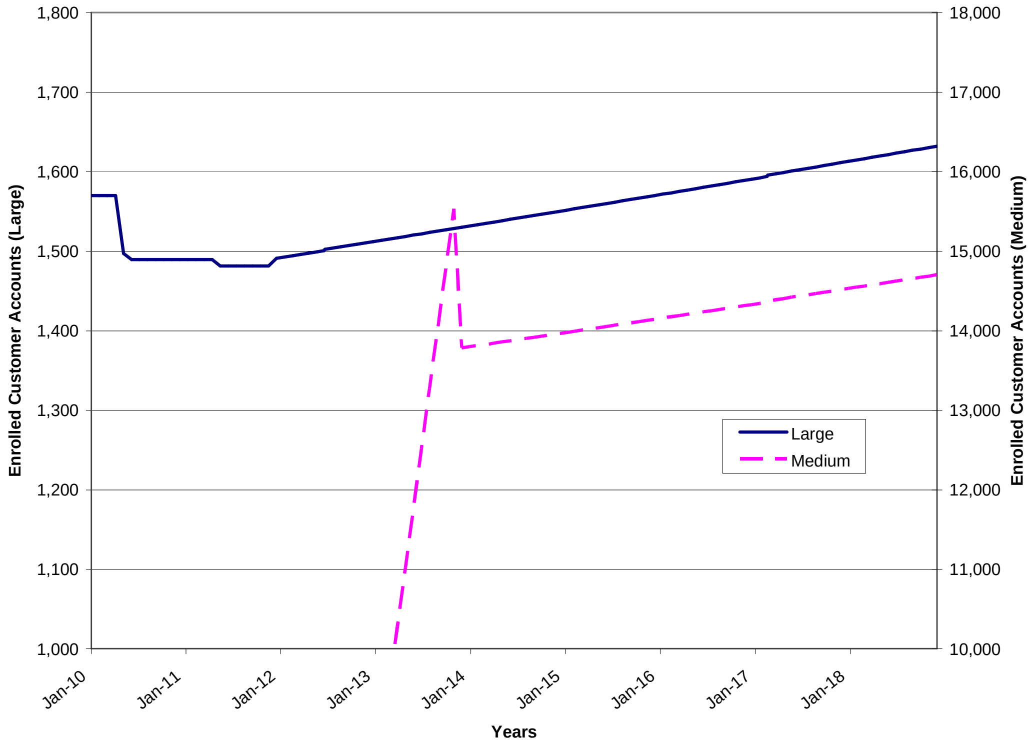
Industry Group	2010	2011	2012
1. Agriculture, Mining & Construction	132	110	96
2. Manufacturing	1381	1137	867
3. Wholesale, Transport & Utilities	676	465	351
4. Retail Stores	678	231	149
5. Offices, Hotels, Health, Services	1327	385	259
6. Schools	611	544	518
7. Entertainment, Other Services & Gov't.	523	255	181
Total	5,328	3,127	2,421

5.3.3 SDG&E

SDG&E produced enrollment forecasts for default CPP for two size categories of customer accounts—medium (20 to 200 kW) and large (over 200 kW). It based the forecasts on assumed opt-out rates, which varied by size category and time. Effective opt-out rates for large customers begin at about 31 percent and rise to 35 percent after the first year. Opt-out rates for medium customers are specified by industry group, averaging 24 percent in the first year and rising to 33 percent in the second year. Enrollments were separately generated for customers with and without enabling technology.

Figure 5.2 shows the total number of customer accounts that are forecast to be enrolled in default CPP across the forecast years. The anticipated increase in opt-out rates for the large customers is reflected in the drop in enrollment during 2010 and 2011. Enrollments are forecast to rise thereafter with customer growth. Enrollments for medium customers rise sharply as interval metering is installed and customers become eligible for default to CPP. The initial opt-outs may be seen following the spike in enrollment in 2013. Thereafter, enrollment grows with forecast customer growth.

Figure 5.2: Forecast of Enrolled Customer Accounts – *SDG&E Default CPP*
(Medium and Large Customer Size)



5.4 Forecast Load Impacts

For each utility and program, we provide the following summary information:

1. A figure showing the hourly profile of the reference load, event-day load, and load impacts for the typical event day in a 1-in-2 weather year;
2. A pie chart showing the share of load impacts by LCA (except for SDG&E) for the typical event day in a 1-in-2 weather year; and
3. Average event-hour load impacts by year for the typical event days of 1-in-2 and 1-in-10 weather years.

Together, these figures provide a useful indication 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 an Excel table generator in an associated electronic file.

5.4.1 PG&E PDP

Figure 5.3 shows load impacts for a typical PDP event day in a 1-in-2 weather year in August 2013.[35] Average hourly load impacts during the common four-hour event window (from 2 p.m. to 6 p.m.) range from 273 MW to 299 MW, which represent 5.5 percent of the reference load.

Figure 5.3: Hourly Event-Day Loads and Load Impacts (kW) for the Typical Event Day in a 1-in-2 Weather Year for August 2013

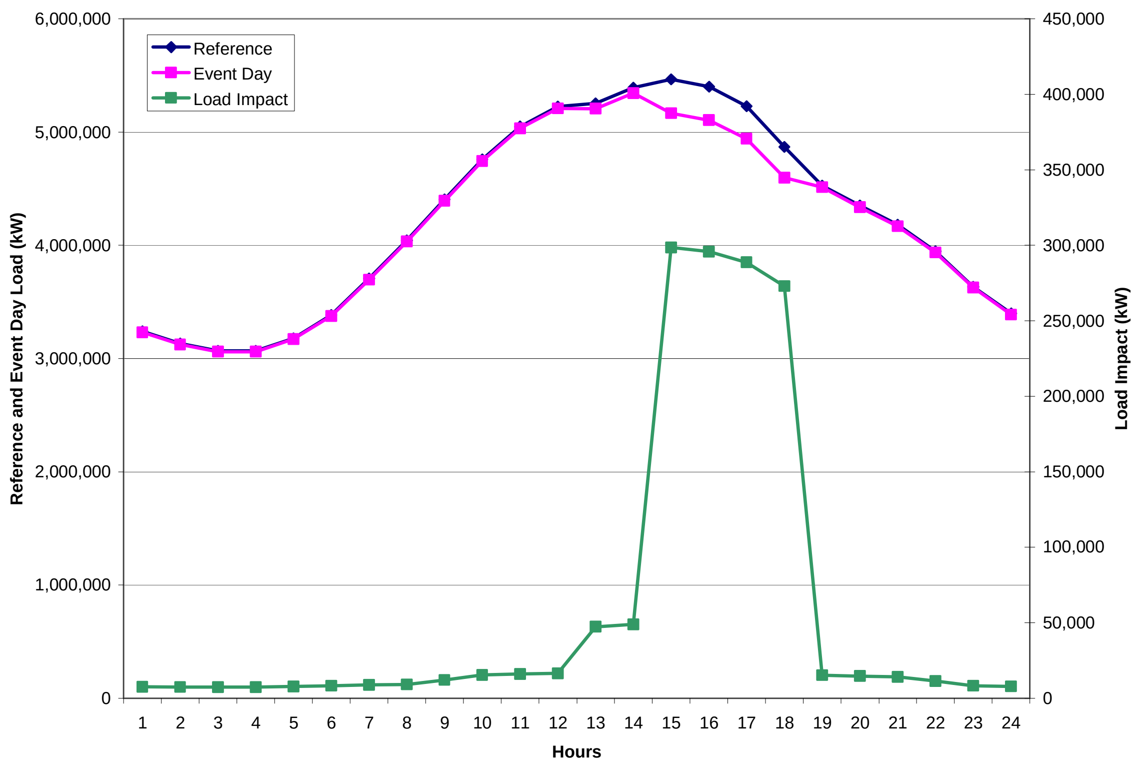


Figure 5.4 shows how the load impacts are distributed by LCA. Customers in the Greater Bay Area account for 44 percent of the load impacts. Customers in Greater Fresno and those not located in an LCA account for the next largest shares, at 12 and 18 percent respectively.

[35] Because CPP event days are not superseded by any other program's event days, program-level load impacts are the same as portfolio-level impacts.

Figure 5.4: Share of Load Impacts by LCA for the August 2013 Peak Day in a 1-in-2 Weather Year

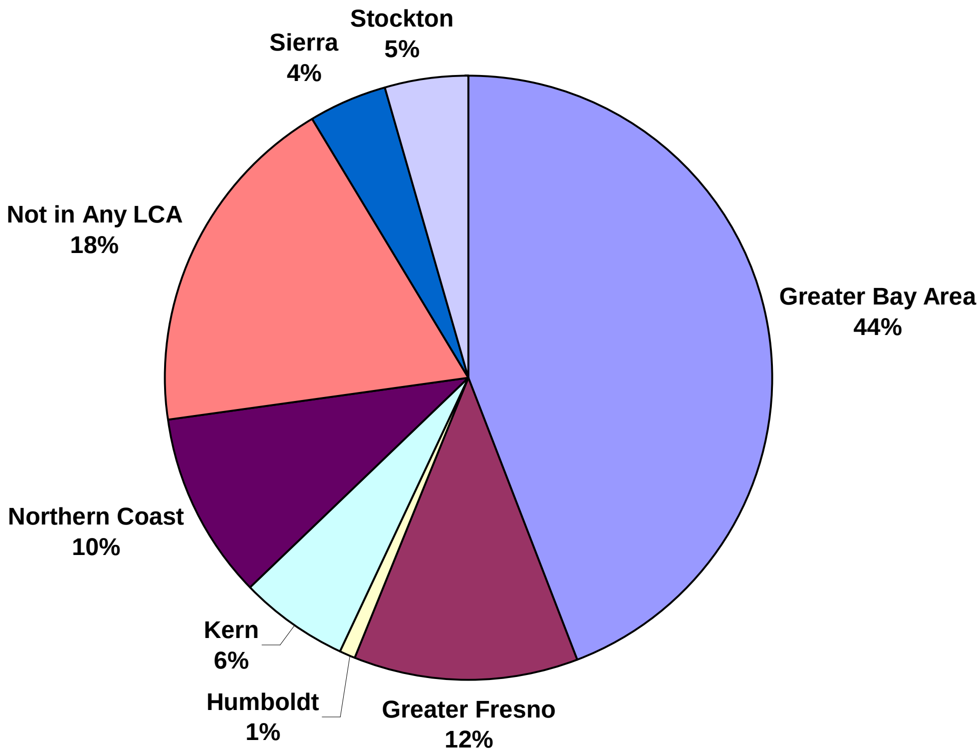
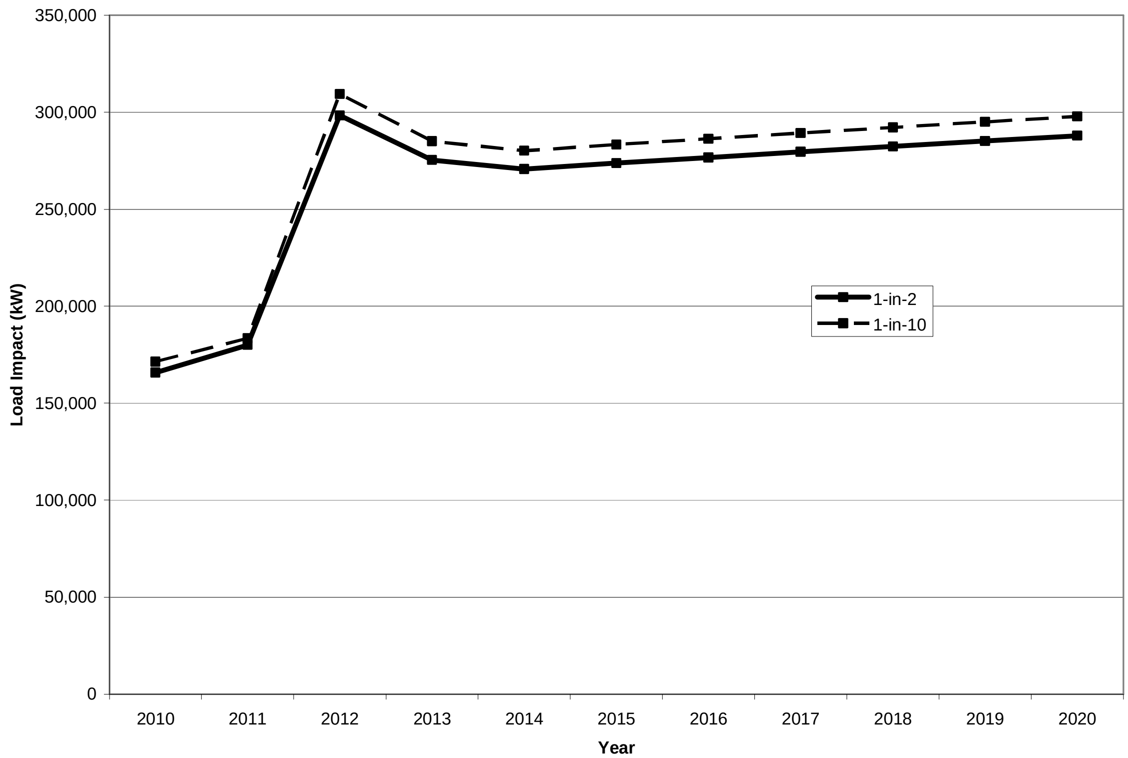


Figure 5.5 illustrates the average hourly load impact across years for the August peak day in a 1-in-2 weather year. Load impacts reach a peak in 2012, then fall somewhat due to opt-out patterns, then level off and rise slowly until 2020.

Figure 5.5: Average Event-Hour Load Impacts (kW) for August Peak Day –
1-in-2 and 1-in-10 Weather Years



5.4.2 SCE CPP

Figure 5.6 shows the load impacts for a typical event day in a 1-in-2 weather year for 2012 and beyond for SCE.[36] (SCE's enrollment forecast is unchanged from 2012 through 2020.) Event-hour load impacts range from 36.1 MW to 44.8 MW, which is approximately 6.3 percent of the enrolled reference load.

Figure 5.7 shows how the load impacts are distributed by LCA. Customers in the LA Basin account for the vast majority of the load impact, at 79 percent.

[36] Because CPP event days are not superseded by any other program's event days, program-level load impacts are the same as portfolio-level impacts.

Figure 5.6: Hourly Event-Day Loads and Load Impacts (kW) for the Typical Event Day in a 1-in-2 Weather Year for August 2012 – *SCE CPP (> 200 kW)*

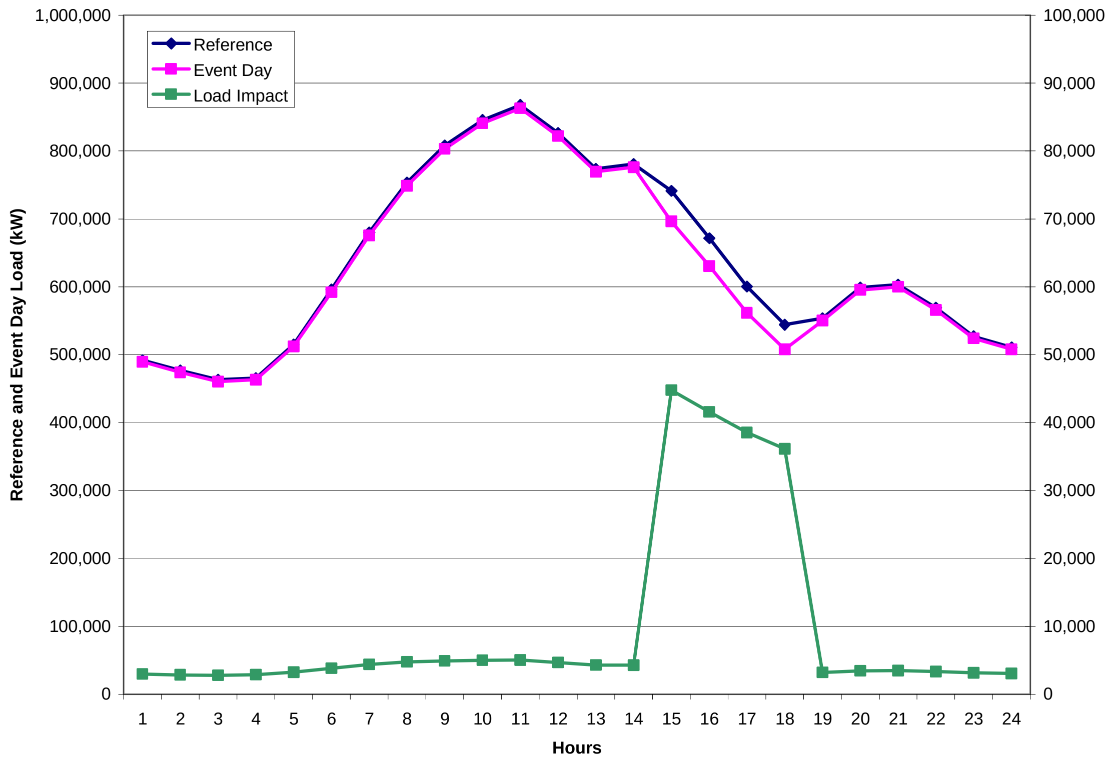


Figure 5.7: Share of Load Impacts by LCA for the Typical Event Day in a 1-in-2 Weather Year for 2012 – *SCE CPP*

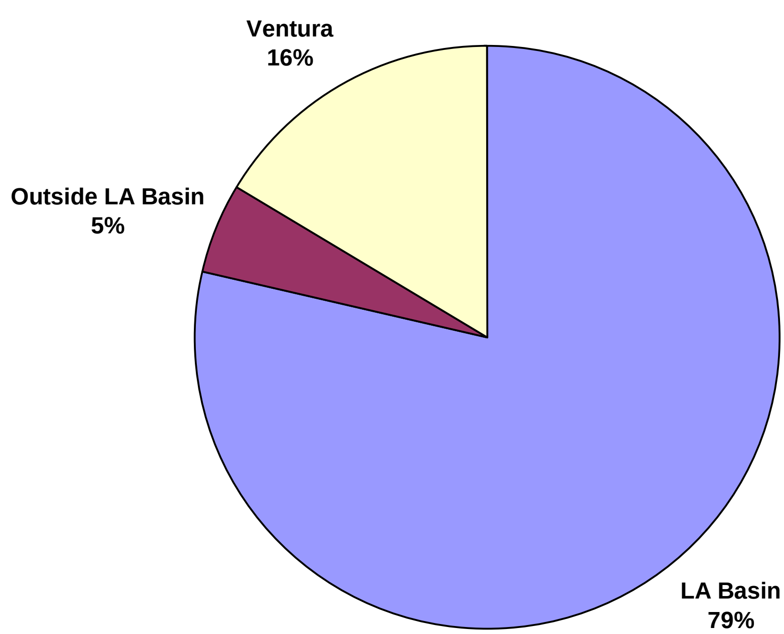
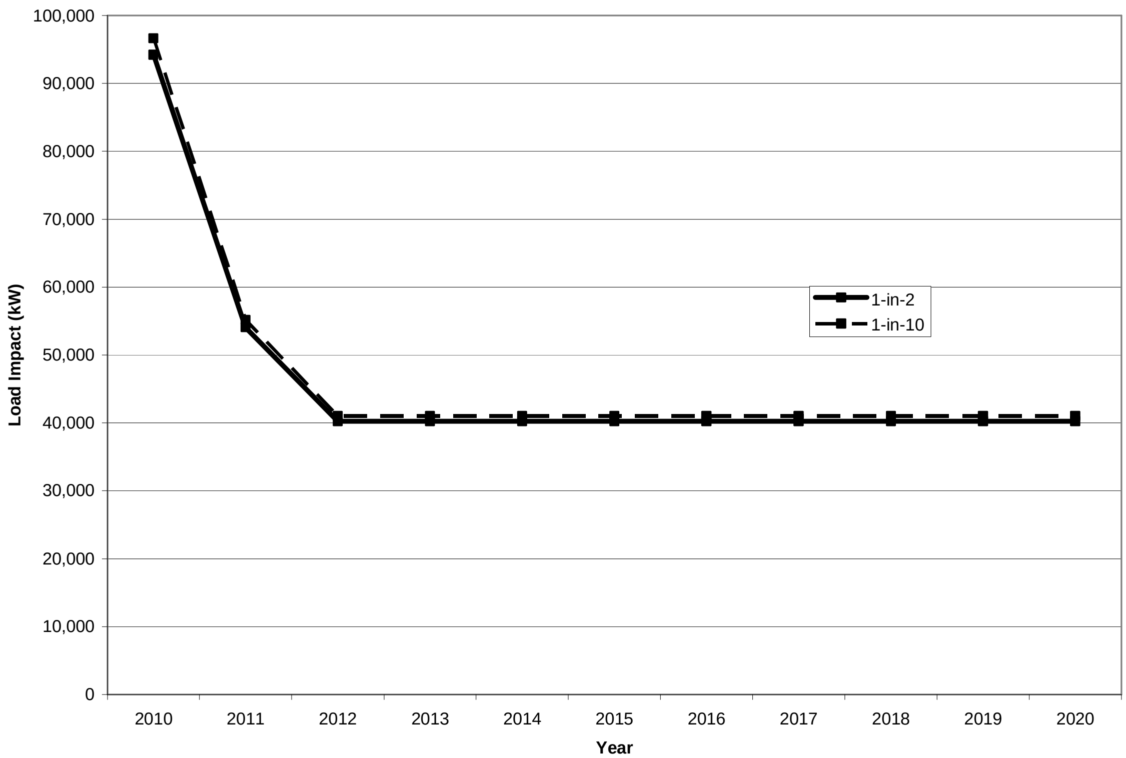


Figure 5.8 presents the average event-hour load impacts across years for the typical event day in 1-in-2 and 1-in-10 weather years. The load impacts drop from 2010 through 2012, as customers are anticipated to opt out of the default CPP rate, and then remain constant through 2020. The long-term average hourly load impact is 40.2 MW in a 1-in-2 weather year.

Figure 5.8: Average Event-Hour Load Impacts (kW) by Forecast Year for the Typical Event Day – *SCE CPP*



5.4.3 SDG&E CPP

Because of the expected major change in the composition of default CPP at SDG&E over the next few years, we show results separately for the generally large customers that are currently on the default CPP rate, and the smaller customers that will begin transitioning to default CPP in the future. Figure 5.9 shows 2013 reference load, event-day load and load impacts (right axis) for a typical event day in a 1-in-2 weather year for the customer accounts currently enrolled in default CPP. Event-hour load impacts range from 21.8 MW to 31.7 MW, which average just under 6 percent of the reference load. Figure 5.10 shows comparable information for the new customer accounts that are expected to be defaulted to CPP beginning in 2013. These are generally medium-sized customer accounts (20 – 200 kW) that will have had interval meters installed for the previous 12 months. Event-hour load impacts for these customers range from 30.4 MW to 33.4 MW, and average 5.9 percent of the estimated reference load.

Figure 5.9: Hourly Reference Loads and Load Impacts (kW) for the Typical Event Day in a 1-in-2 Weather Year for 2013 – *Existing CPP Customers*

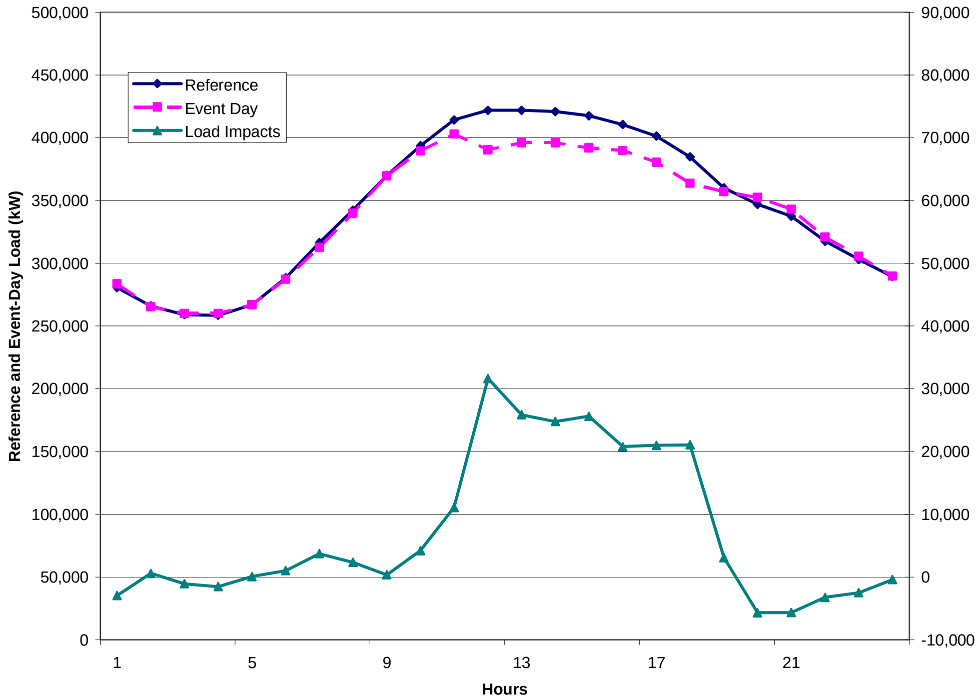


Figure 5.10: Hourly Reference Loads and Load Impacts (kW) for the Typical Event Day in a 1-in-2 Weather Year for 2013 – *New CPP Customers*

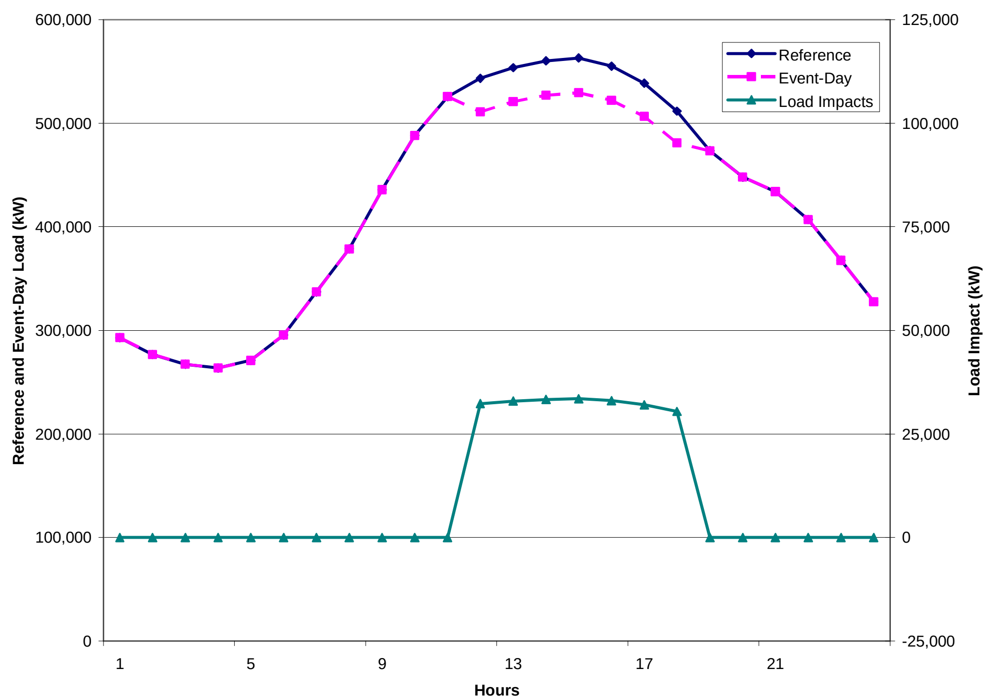


Figure 5.11 shows the estimated reference load, event-day load and load impacts for existing default CPP customers under a Portfolio scenario in which the reference loads and load impacts of those customers enrolled in both CPP and the CBP *day-of* program type (or the new AMP program) have been removed to reflect the fact that for resource adequacy purposes CBP, being a capacity-based program, dominates CPP. Under this scenario, hourly load impacts fall to a range of 18.8 to 28.5 MW.

Figure 5.11: Hourly Reference Loads and Load Impacts (kW) for the Typical Event Day in a 1-in-2 Weather Year for 2013 – *Existing CPP Customers (Portfolio)*

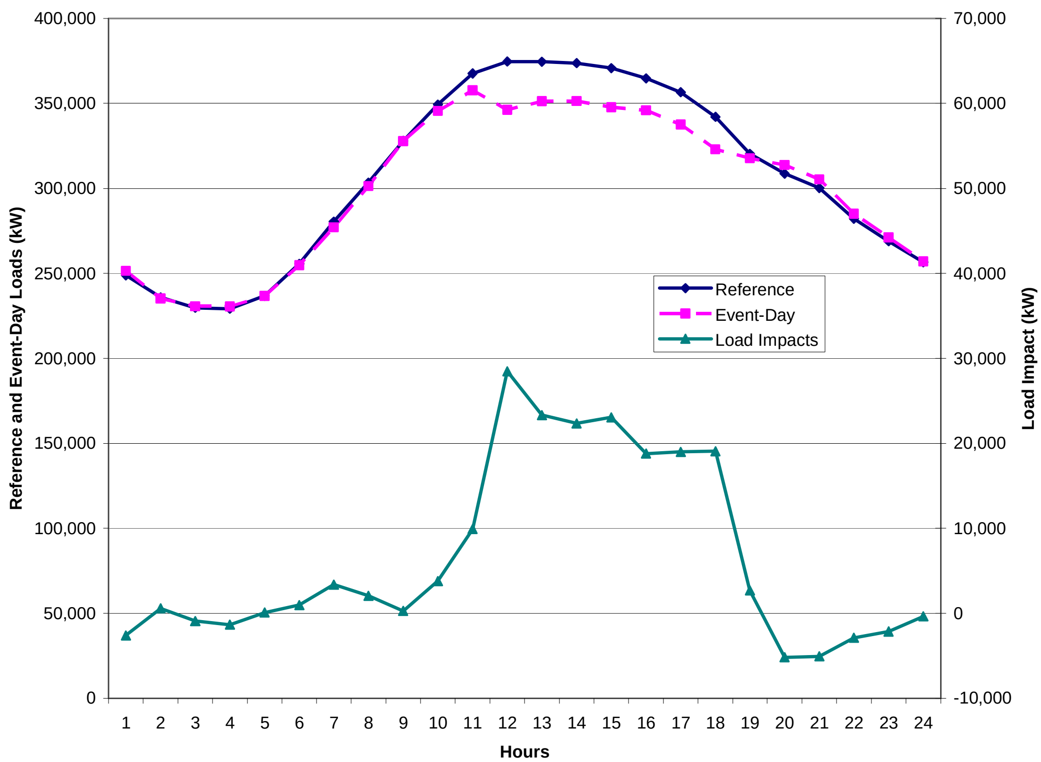
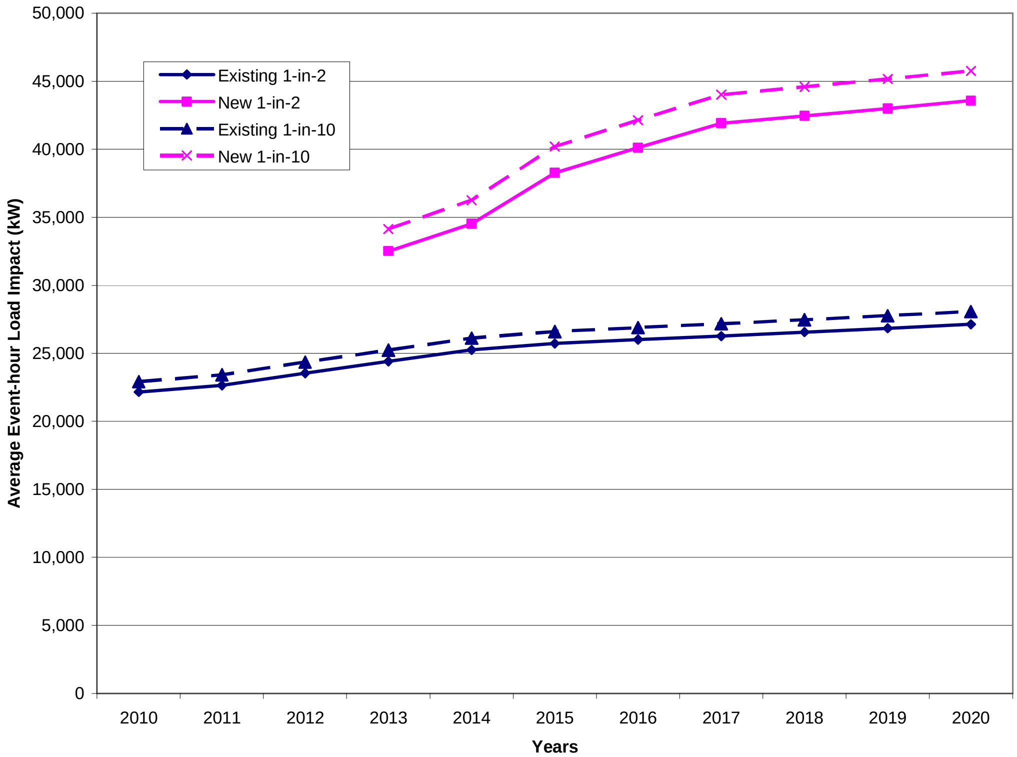


Figure 5.12 illustrates the average hourly load impact across years for a typical event day for both 1-in-2 and 1-in-10 weather years for the current and expected new CPP customer accounts. The load impacts for the new customers are shown beginning in 2013, and growing more rapidly than those for the current CPP customers. The 1-in-10 weather year load impacts are expected to be 3.4 percent higher than the 1-in-2 weather year load impacts for the existing customers and 5 percent higher for the new customers.

Figure 5.12: Average Event-Hour Load Impacts (kW) by Forecast Year and Weather Scenario for a Typical Event Day
Existing and New CPP Customer Accounts



6. Validity Assessment

We estimated load impacts using service account-specific regression models. This method has some advantages relative to the aggregated models (*e.g.*, properly accounting for when each SAID joined CPP, and allowing the results to be summarized according to any observed customer characteristic without requiring the estimation of a new model). However, it does require estimation of many models. Thus, time constraints prevent a detailed examination of each SAID's model. In addition, in order to facilitate post-processing the results, it is important to use a uniform model structure across all of the service accounts in a program.

Our primary concern with respect to the validity of the findings is regarding the appropriateness of the model specification that is used. We believe that the most significant issue in an ex post analysis of load impacts is the risk of omitted variable bias. That is, loads levels may change for reasons that cannot be easily known to the analyst, and consequentially those reasons cannot be captured in the econometric models. For example, it is not uncommon for manufacturing customers to shut down operations for one to two weeks. Such activity can bias the estimates for the other included variables if variables are not included to explicitly account for such a "shut down".

In order to minimize the potential for omitted variable bias, we screen the SAID-level models to determine whether the load impacts appear to be "real". Because of time and resource constraints, we limit the screening to the models containing the largest estimated load impacts (positive and negative). For these service accounts, we extract the observed loads for each week in which an event day occurred. We then graph the daily loads for each event week. This provides an informal day-matching method for confirming the estimated customer load impacts. For cases in which this visual examination provides a clear confirmation that the estimation model does not properly capture the SAID's regular usage patterns and that the customer does not appear to change its behavior because of CPP event days, we zero out the estimated load impact. Otherwise, we retain the estimates for the higher level summaries of load impacts.

In addition to the screening issue described above, we explored alternative estimation models for SDG&E's service accounts. We noticed that the implied reference loads (which are equal to the observed loads plus the estimated load impacts) for weather-sensitive industry groups (*e.g.*, offices, etc.) appeared to be too high. That is, the load profile implied by the models that reflects the usage that would have occurred in the absence of the event rose to levels that we did not observe in the historical data for non-event days. We therefore examined models with alternative weather variables and found that adding variables with the square of cooling degree hours resulted in implied reference loads that were more in line with observed historical data. This issue did not appear to be relevant for the PG&E and SCE estimates.

7. Recommendations

As the default CPP programs grow, it will become increasingly difficult to conduct the customer-level analyses described in this report. This will be due to the need to obtain and analyze large amounts of hourly data for each of a much larger number of enrolled service accounts. In the future (when there will likely be tens or hundreds of thousands of service accounts on CPP or PDP), it may be advisable to conduct the analysis using a *sample* of enrolled service accounts, with appropriate sample weights developed with reference to databases of customer characteristics all enrolled customer accounts.

Progress can be made on this methodological issue outside of the time period that is typically devoted to estimating load impacts (from November through March). We would recommend that the utilities engage in discussions regarding the feasibility of the sampling method, and the specific methods that would be used to implement the technique. If the method is approved, we would recommend that the sample selection process occur as early as possible to enable sufficient time to conduct the remainder of the load impact analyses.

Regarding TA/TI and AutoDR program performance, there is some anecdotal evidence from PG&E that participating customers require additional assistance in understanding the demand response programs in which they are enrolled. Such confusion contributed to our findings of under-performance in PG&E's TA/TI program.