2009 Load Impact Evaluation of California Statewide Demand Bidding Programs (DBP) for Non-Residential Customers: Ex Post and Ex Ante Report

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Table of Contents

Tables

Figures

Abstract

This report documents an ex post and ex ante load impact evaluation for the Demand Bidding Program ("DBP") administered by two of California's large investor-owned utilities in 2009. The evaluation first reports on the estimation of DBP load impacts that occurred on the event days called during the 2009 program year at Pacific Gas and Electric Company ("PG&E") and Southern California Edison ("SCE"). Load impact results are reported at the program level, by industry type, and by local capacity area. Ex ante forecasts of load impacts are then reported based on enrollment forecasts provided by the utilities and a characterization of the per-customer load impacts observed in 2009. A baseline analysis was also conducted to compare the program's baseline method, the 3-in-10 method, to baselines implied by the estimated regression equations and to the alternatives of unadjusted and adjusted 10-in-10 methods.

DBP is a voluntary Internet-based demand response bidding program that provides enrolled customers with the opportunity to receive financial incentives in payment for providing load reductions on event days. Credits are paid based on the difference between the customers' actual metered load during an event to a reference load, or baseline, which is calculated from each customer's usage data prior to the event. Notice for events may be sent to the customer the day before, or the day of the event.

PG&E called one DBP event in 2009, a four-hour test event on August 28th that lasted from 2 p.m. to 6 p.m., and which overlapped with a BIP test event. SCE called fifteen DBP events in 2009, all lasting eight hours, from noon to 8 p.m., except for one four-hour test event.

Enrollment in PG&E's DBP was 1,127 customer service accounts in 2009, down slightly from 1,165 in 2008. Enrollments in previous years were 866 accounts in 2006 and 1,063 in 2007. Total DBP load, represented by the sum of enrolled customers' individual maximum demands[1], amounted to 1,383 MW. The manufacturing; and offices, hotels, health care and services industry groups made up the majority of PG&E's DBP enrollment. SCE's enrollment in DBP has expanded from 1,079 customer service accounts in 2006, 1,222 in 2007, and 1,244 in 2008, to 1,368 customer service accounts in 2009. These accounted for 1,503 MW of maximum demand. Manufacturers continued to make up more than half of the enrolled load.

As in previous years, only a relatively small percentage of the customer accounts enrolled in DBP actually submitted bids for most events. Fewer than 100 PG&E customers, representing 18 percent of the enrolled load, submitted a bid for the test event. At SCE, 504 customer accounts, representing less than 40 percent of the customers, but more than half the enrolled load, submitted at least one bid during 2009.

Ex post load impacts were estimated from regression analysis of individual customer-level hourly load data, where the equations modeled hourly load as a function of several

[1] Customer-level demand is calculated as the average of the monthly maximum demands during the program months.

variables designed to control for factors affecting consumers' hourly demand levels. DBP load impacts for each event were obtained by summing the estimated hourly event coefficients for all customers who submitted a bid for that event. The individual customer models also allow the development of information on the distribution of load impacts across industry types and geographical regions, by aggregating customer load impacts for the relevant industry group or local capacity area.

The total program load impact for PG&E's test event averaged 53.5 MW, or 5.5 percent of enrolled load. Hourly load impacts ranged from 3.9 to 103.5 MW, with the largest values representing approximately 10 percent of the total DBP reference load for enrolled customers. The very large variation in hourly load impacts (and reference loads) across the event was due to an overlap with a BIP event. Customer service accounts enrolled in both BIP and DBP tended to submit bids for only the last two (post-BIP) hours of the DBP event, and to carry forward the very large load response that they exhibited during the BIP event hours into the remaining DBP event hours. The level of DBP load impacts that remained after excluding the overlapping BIP customers was rather small, at approximately 4 MW, or 0.6 percent of the reference load.

For SCE, average hourly program load impacts averaged approximately 41.6 MW across fifteen events. The load impacts showed some variation across event days, with a low of 25.5 MW and a high of 58.8 MW. On average, the load impacts were about 4.2 percent of the total reference load.

An analysis of the load impacts of 41 customer accounts who participated in TA/TI or AutoDR programs found total load impacts of about 1.5 MW for AutoDR customer accounts at both PG&E and SCE, and nearly 9 MW for TA/TI customers. Attempts to estimate *incremental* load impacts by comparison to similar customers were largely unsuccessful.

The baseline comparisons pointed to several consistent findings. First, all of the baseline methods applied to *commercial*-type customer accounts tended to be more accurate and less biased relative to the regression-based baseline than they did for *industrial*-type or *school* accounts. Second, the unadjusted 3-in10 program baseline tended to *over-state* the regression-based baseline by more than did the unadjusted 10-in-10 baseline (which is not surprising since the 3-in-10 uses the 3 days with highest loads from among the 10 available). Third, the *adjusted* 10-in-10 baseline tended to reduce both over-statements and under-statements of the unadjusted baseline, and would thus be likely to improve accuracy and bias in calculating load impacts for DBP, compared to unadjusted versions of either the 3-in-10 or 10-in-10 baseline.

In the ex ante evaluation, SCE forecasts that DBP customer enrollment will remain stable at 2009 program year levels during the forecast time period, while PG&E forecasts declining DBP enrollments, and load impacts falling from approximately 25 MW in 2010 to approximately 15 MW in 2020.

Executive Summary

This report documents ex post and ex ante load impact evaluations for the statewide Demand Bidding Program ("DBP") in place at Pacific Gas and Electric Company ("PG&E") and Southern California Edison ("SCE") in 2009. (San Diego Gas and Electric Company discontinued its program in 2009.) The report first provides estimates of ex post load impacts that occurred during events called in 2009. The report then documents an ex ante forecast of load impacts for 2010 through 2020 that is based on utility enrollment forecasts and the ex post load impacts estimated for 2009.

The primary research questions addressed by this evaluation are:

1. What were the DBP load impacts in 2009?
2. How were the load impacts distributed across industry groups?
3. How were the load impacts distributed across CAISO local capacity areas?
4. What were the effects of TA/TI and AutoDR on customer-level load impacts?
5. How did the program's baseline loads, calculated using the 3-in-10 method, compare to baselines implied by the estimated regression equations and to the alternative of unadjusted and adjusted 10-in-10 methods?
6. What are the ex ante load impacts for 2010 through 2020?

ES.1 Resources covered

DBP Program

DBP, which was created in 2001, is a voluntary Internet-based demand response bidding program that provides enrolled customers with the opportunity to receive financial incentives in payment for load reductions on event days. Credits are paid based on the difference between the customers' actual metered load during an event to a reference load, or baseline, which is calculated from each customer's usage data prior to the event. Notice for events may be sent to the customer the day before, or the day of the event.

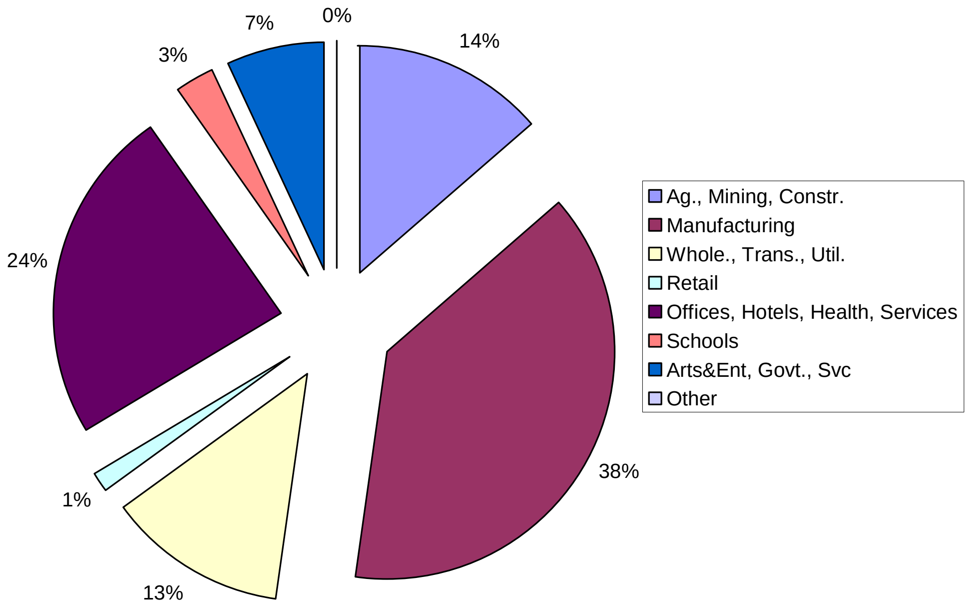
PG&E called one DBP event in 2009, a four-hour test event on August 28th that lasted from 2 p.m. to 6 p.m. SCE called fifteen DBP events in 2009, all lasting eight hours, from noon to 8 p.m., except for one four-hour test event.

Enrollment

Enrollment in PG&E's DBP declined slightly from 1,165 customer service accounts in 2008 to 1,127 in 2009. Enrollments in previous years were 866 accounts in 2006 and 1,063 in 2007. Total DBP load, represented by the sum of enrolled customers' individual maximum demands[2], amounted to 1,383 MW. The manufacturing; and offices, hotels, health care and services industry groups made up the majority of PG&E's DBP enrollment. Figure ES.1 illustrates the distribution of DBP load across the indicated industry types.

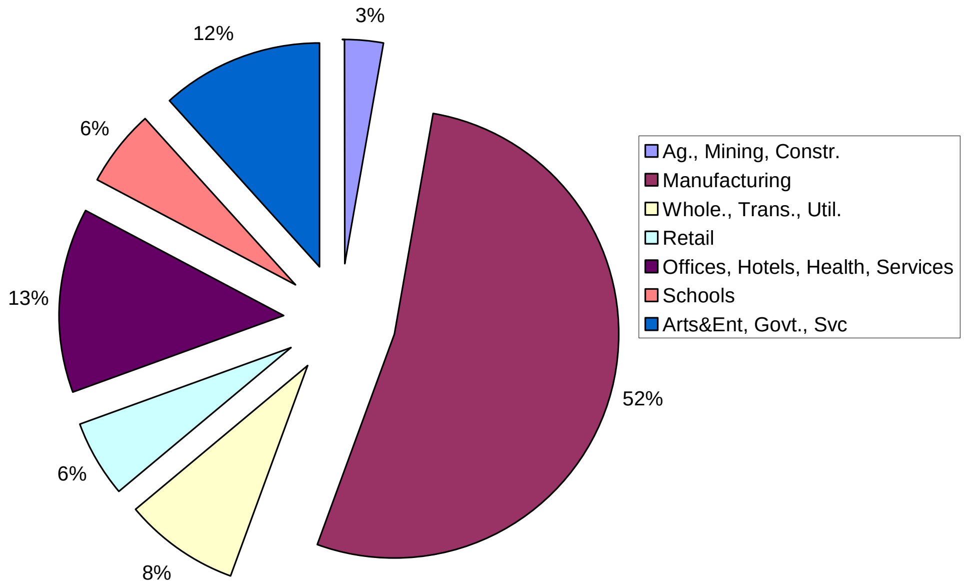
[2] Customer-level demand is calculated as the average of the monthly maximum demands during the program months.

Figure ES.1 Distribution of DBP Enrollment by Industry Type – *PG&E*



SCE's enrollment in DBP has expanded from 1,079 customer service accounts in 2006, 1,222 in 2007, and 1,244 in 2008, to 1,368 customer service accounts in 2009. These accounted for 1,503 MW of maximum demand. Manufacturers continued to make up more than half of the enrolled load, as shown in Figure ES.2.

Figure ES.2 Distribution of DBP Enrollment by Industry Type – *SCE*



Bidding Behavior

As in previous years, only a relatively small percentage of the customer accounts enrolled in DBP submitted bids for most events. Fewer than 100 PG&E customers, representing 18 percent of the enrolled load, submitted a bid for the test event. At SCE, 504 customer accounts, representing more than half the enrolled load, submitted at least one bid during 2009.

ES.2 Evaluation Methodology

We estimated ex post load impacts using regression analysis of customer-level hourly load data. Individual-customer regression equations modeled hourly load as a function of several variables designed to control for factors affecting consumers' hourly demand levels, including:

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

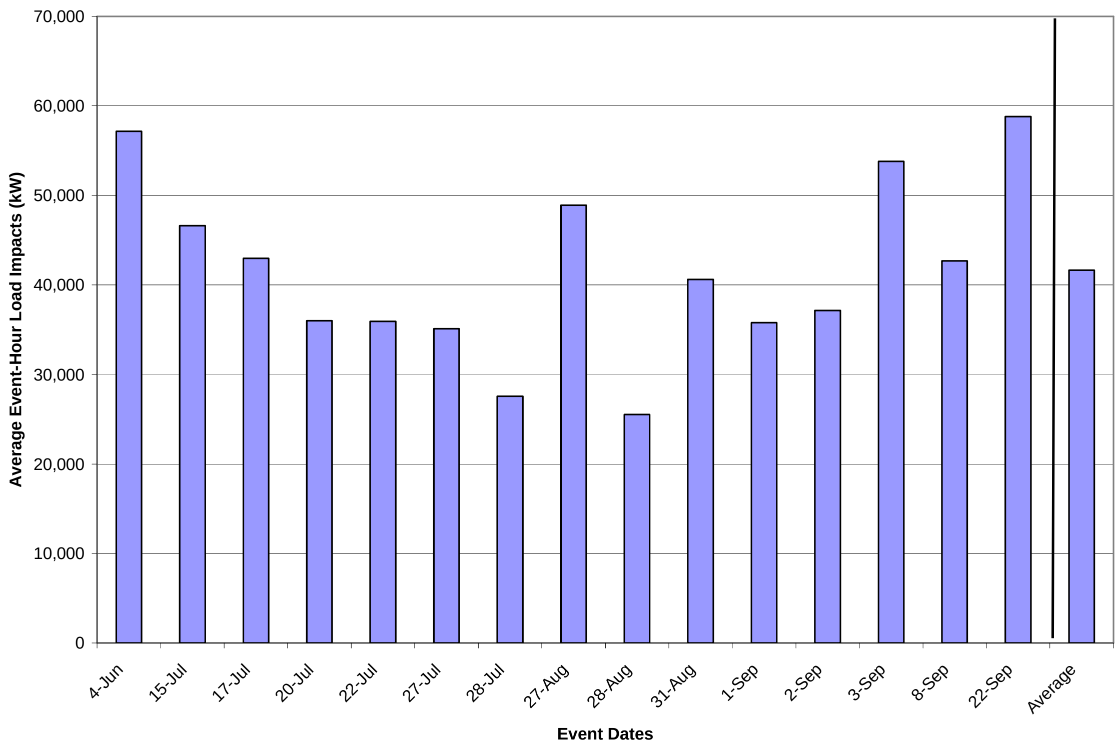
DBP load impacts for each event were obtained by summing the estimated hourly event coefficients for all customers who submitted a bid for that event. The individual customer models allow the development of information on the distribution of load impacts across industry types and geographical regions, by aggregating customer load impacts for the relevant industry group or local capacity area.

ES.3 Ex Post Load Impacts

The total program load impact for PG&E's test event averaged 53.5 MW, or 5.5 percent of enrolled load. The Manufacturing industry group accounted for the largest share of the load impacts. Hourly load impacts ranged from 3.9 to 103.5 MW, with the largest values representing approximately 10 percent of the total DBP reference load for enrolled customers. The very large variation in hourly load impacts (and reference loads) across the event was due to an overlap with a BIP event. Service accounts enrolled in both BIP and DBP tended to submit bids for only the last two hours of the DBP event, and to carry forward the very large load response that they exhibited during the BIP event hours into the remaining DBP event hours. The level of DBP load impacts that remained after excluding the overlapping BIP customers was rather small, at approximately 4 MW, or 0.6 percent of the reference load.

For SCE, the total average hourly program load impact averaged approximately 41.6 MW across fifteen events. Figure ES.3 shows the average hourly load impacts for each event, and for the average event day. The load impacts showed some variation across event days, with a low of 25.5 MW and a high of 58.8 MW. On average, the load impacts were about 4.2 percent of the total reference load.

Figure ES.3: Average Hourly DBP Load Impacts by Event – *SCE*



On a summary level, the average per-customer event-hour load impact was 48 kW for PG&E's program and 33 kW for SCE's program.

ES.4 TA/TI and AutoDR Effects

Ex post load impacts were also estimated for subsets of DBP customer accounts that participated in two demand response incentive programs: TA/TI and AutoDR. The Technical Assistance and Technology Incentives (TA/TI) program has two parts: technical assistance in the form of energy audits, and technology incentives. The objective of the TA portion of the program is to subsidize customer energy audits so that they can identify ways to participate effectively 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.1 shows the total load impacts achieved by DBP bidders who participated in one of the technology incentive programs, by utility. The estimated percentage load impacts ranged from 8.8 to 25.8 percent of the reference loads, with the larger percentage load impacts coming from SCE customer accounts. The total average hourly load impact for AutoDR was similar for PG&E and SCE, at about 1.5 MW.

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 of participants and non-participants at the 6-digit NAICS level (or 4-digit SIC level for SCE). These comparisons provided mixed results.

Table ES.1: Total AutoDR and TA/TI Load Impacts by Utility

Utility	Program	# SAIDs	Average Hourly Load Impact (kW)	Percentage Load Impact
PG&E	AutoDR	13	1,474	8.8%
	TATI	n/a	n/a	n/a
SCE	AutoDR	9	1,378	24.3%
	TATI	19	8,767	25.8%

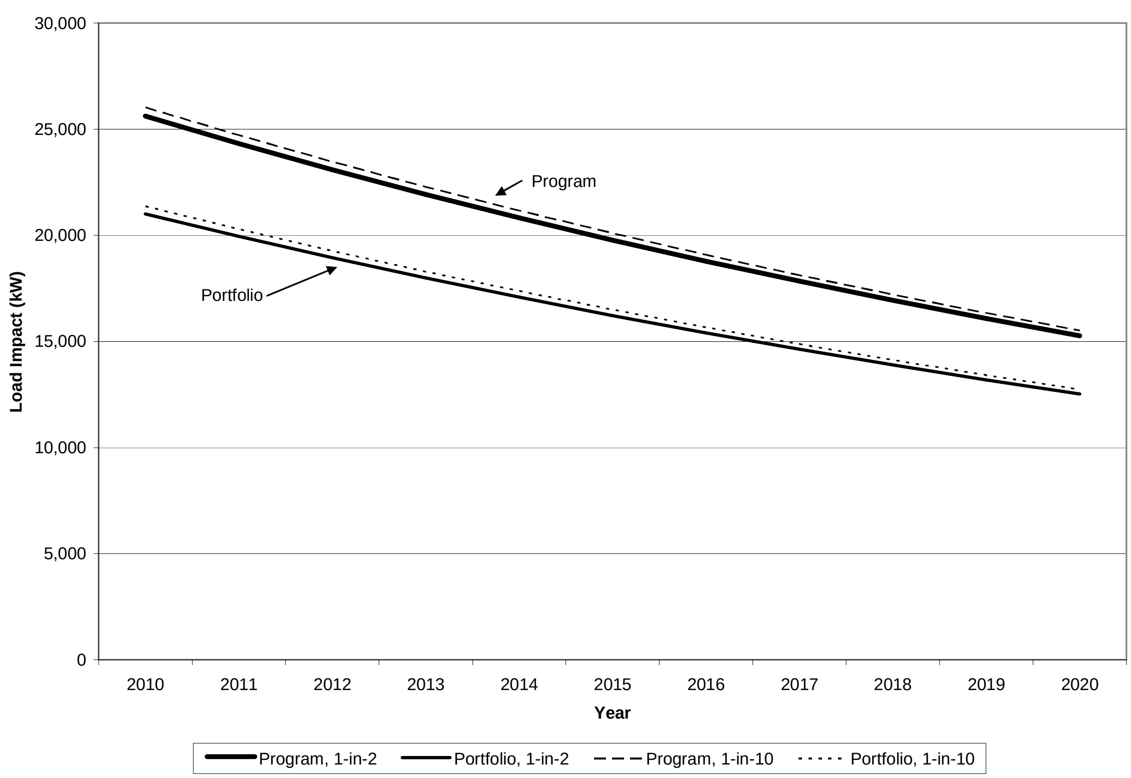
ES.5 Baseline Analysis

The baseline analysis involved a comparison of three alternative baseline loads (the 3-in-10 program baseline method, a 10-in-10 baseline method, and an adjusted 10-in-10 method) to the baseline implied by the load impact regression equations, for each customer account submitting a bid for DBP events at PG&E and SCE. The baseline comparisons pointed to several consistent findings. First, all of the baseline methods applied to *commercial*-type customer accounts tended to be more accurate and less biased relative to the regression-based baseline than they did for industrial-type or school accounts. Second, the unadjusted 3-in10 program baseline tended to over-state the regression-based baseline by more than the unadjusted 10-in-10 baseline (which is not surprising since the 3-in-10 uses the 3 days with highest loads from among the 10 available). Third, the *adjusted* 10-in-10 baseline tended to reduce both over-statements and under-statements of the unadjusted baseline, and would thus be likely to improve accuracy and bias in calculating load impacts for DBP, compared to unadjusted versions of either the 3-in-10 or 10-in-10 baseline.

ES.6 Ex Ante Load Impacts

SCE forecasts that DBP customer enrollment will remain stable at 2009 program year levels during the forecast time period. PG&E forecasts declining DBP enrollments over the forecast time period. Figure ES.4 illustrates the level of estimated load impacts for PG&E across the forecast time period. There is little difference between the load impacts in 1-in-2 and 1-in-10 weather years. *Program-level* load impacts are significantly higher than *portfolio-level* load impacts in all forecast years, due to DBP being dominated by capacity-based programs and CPP/PDP for jointly enrolled customers. At the program level, DBP load impacts drop from approximately 25 MW in 2010 to approximately 15 MW in 2020.

Figure ES.4: Average PG&E DBP Hourly Load Impacts by Year
by Program and Portfolio Scenario, and 1-in-2 and 1-in-10 Weather Years



ES.7 Summary

In 2009, PG&E called one four-hour DBP test event and SCE called 15 events. PG&E's test event overlapped with a two-hour BIP event, which had a significant effect on estimated DBP load impacts because of dual enrollments in the two programs. During the overlapping hours, DBP load impacts averaged only 5.3 MW, or 0.6 percent of the reference load. In contrast, during the DBP-only hours, load impacts averaged 102.9

MW, or 10 percent of the reference load. This large difference is explained by the fact that BIP customers could not participate in the DBP event during BIP event hours, but appeared to “carry over” their BIP-induced demand response into the subsequent DBP event hours. It is difficult to determine how large the DBP load impacts would have been in the absence of a BIP event.

Ex post load impacts for SCE’s 15 events averaged 41.6 MW, or 4.2 percent of the reference load.

SCE's ex ante load impacts are forecast to average 42.3 MW during the typical event day in a 1-in-2 weather year. For PG&E, the program-level ex ante load impacts are forecast to decline from approximately 25 MW in 2010 to 15 MW in 2020. The portfolio-level load impacts decline from 21 MW in 2010 to 12.5 MW in 2020.

1. Introduction and Purpose of the Study

This report documents ex post and ex ante load impact evaluations for the statewide Demand Bidding Program ("DBP") in place at Pacific Gas and Electric Company ("PG&E") and Southern California Edison ("SCE") in 2009. (San Diego Gas and Electric Company discontinued its program in 2009.) The report first provides estimates of ex post load impacts that occurred during events called in 2009. The report then documents an ex ante forecast of load impacts for 2010 through 2020 that is based on utility enrollment forecasts and the ex post load impacts estimated for 2009.

The primary research questions addressed by this evaluation are:

1. What were the DBP load impacts in 2009?
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3. How were the load impacts distributed across CAISO local capacity areas?
4. What were the effects of TA/TI and AutoDR on customer-level load impacts?
5. How did the program's baseline loads, calculated using the 3-in-10 method, compare to baselines implied by the estimated regression equations and to the alternative of unadjusted and adjusted 10-in-10 methods?
6. What are the ex ante load impacts for 2010 through 2020?

The report is organized as follows. Section 2 contains a description of the DBP programs, the enrolled customers, and the events called; Section 3 describes the methods used in the study; Section 4 contains the detailed ex post load impact results, including estimates of the incremental effect of TA/TI and AutoDR on load impacts; Section 5 provides a comparison of baseline methods; Section 6 describes the ex ante load impact forecast; Section 7 contains an assessment of the validity of the study; and Section 8 provides recommendations.

2. Description of Resources Covered in the Study

This section provides details on the Demand Bidding Programs, including the credits paid, the characteristics of the participants enrolled in the programs, and the events called in 2009.

2.1 Program Descriptions

DBP is a voluntary bidding program that offers qualified participants the opportunity to receive bill credits for reducing power when a DBP event is triggered on a day-ahead or day-of basis. First approved in CPUC D.01-07-025, modifications have been made to the program, including changes made for the 2006-2008 program cycle at the direction of the CPUC in D.05-01-056. The utilities' DPB programs are designed for non-residential customers, both bundled service and direct access customers. Customers must have internet access and communicating interval metering systems approved by each of the Joint Utilities. A DBP event may occur any weekday (excluding holidays) between the hours of noon and 8:00 pm and may be triggered either on a *day-ahead* or a *day-of* basis. These events may occur at any time throughout the year. Restrictions exist for customers enrolled in multiple DR programs to avoid multiple payments for load reductions during the same event period.

PG&E's DBP Program

At PG&E, DBP is available to time-of-use customers with billed maximum demands of 200 kW or higher (less for aggregated customer service accounts) who commit to reduce load by a minimum of 50 kW in each hour during a DBP event. Eligible customers must have an interval meter which is paid for by PG&E, except for direct access customers. For aggregated customer service accounts, there must be at least one service agreement with a maximum demand of 200kW or greater for at least one or more of the past 12 billing months within each aggregated group that will be designated as the primary service agreement for the aggregated group.

The DBP program operates year-round and can be called from 12:00 p.m. to 8:00 p.m. on weekdays, excluding holidays. There is no limit to the number of days on which DBP events may be called. Notification of an event day may be provided on either a day-ahead or day-of basis. Day-ahead events are triggered with a California ISO Alert Notice for the following day, or when the California ISO's day-ahead peak demand forecast is 43,000 MW or greater. Day-of events are triggered when the California ISO issues an energy warning. When an event day is called, enrolled customers may choose to bid a load reduction for the event or not to participate for that event.

For events called a day ahead, the incentive payment is $0.50 per kWh reduced below a baseline level; for events called on the same day, the incentive payment is $0.60 per kWh. Customers must reduce load by a minimum of 50 percent of their bid amount to qualify for a credit, and they are paid for load reductions up to 150 percent of their bid amount. The hourly baseline for load reductions is calculated as the highest three usage values from the previous ten qualifying days (non-holiday, non-event weekdays). There is no penalty for failing to comply with the terms of the submitted bid. Each bid must be a minimum of two consecutive hours during the event. Bids must meet the threshold of 50kW for each hour and customers may submit only one bid for each event notification.

Although PG&E customers currently enrolled in CPP may participate in DBP, they do not receive a DBP incentive payment for those hours in which a DBP event and a CPP event occur simultaneously. DBP customers may also be enrolled in the Business Energy Coalition (BEC) program, the Base Interruptible Program (BIP), the Optional Binding Mandatory Curtailment (OBMC) and/or the Scheduled Load Reduction Program (SLRP).

SCE's DBP Program

SCE's DBP program design is similar to PG&E's, with two exceptions: enrolled customers are required to commit to a minimum load reduction of 30 kW (versus 50 kW at PG&E); and bidding customers are paid for load reductions up to 200 percent of their bid amount. DBP participants may also participate in CPP. However, if a DBP event is called on the same day as a CPP event, CPP has priority, in that consumers are charged CPP prices during event hours and are prohibited from bidding and receiving DBP payments for load reductions during the CPP event hours.

SDG&E's DBP Program

SDG&E discontinued its DBP in 2009.

2.2 Participant Characteristics

2.2.1 Development of Customer Groups

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 according to their applicable two-digit NAICS codes:[3]

1. Agriculture, Mining and Oil and Gas, Construction: 11, 21, 23
2. Manufacturing: 31-33
3. Wholesale, Transport, other Utilities: 22, 42, 48-49
4. Retail stores: 44-45
5. Offices, Hotels, Finance, Services: 51-56, 62, 72
6. Schools: 61
7. Entertainment, Other services and Government: 71, 81, 92
8. Other or unknown.

In addition, each utility provided information regarding the CAISO Local Capacity Area (LCA) in which the customer resides (if any).[4]

2.2.2 Program Participants by Type

The following sets of tables summarize the characteristics of the participating customer accounts, including customer size—categorized by maximum demand—as well as industry type, for PG&E and SCE.

The following sets of tables summarize the characteristics of the participating customer accounts, including size, industry type, and LCA. Table 2.1 shows DBP enrollment by industry group for PG&E. Enrollment in PG&E's DBP declined slightly from 1,165 customer service accounts in 2008 to 1,127 in 2009. Enrollments in previous years were 866 accounts in 2006 and 1,063 in 2007. Total DBP load, represented by the sum of enrolled customers' individual maximum demands[5], amounted to 1,383 MW. Average hourly usage for enrolled customers was 903 MW.[6] The manufacturing; and offices,

[3] 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.

[4] Local Capacity Area (or LCA) refers to a CAISO-designated load pocket or transmission constrained geographic area for which a utility is required to meet a Local Resource Adequacy capacity requirement. There are currently seven LCAs within PG&E's service area, 3 in SCE's service territory, and 1 representing SDG&E's entire service territory. In addition, PG&E has many accounts that are not located within any specific LCA. These are categorized here as being Not in any LCA.

[5] Customer-level demand is calculated as the average of the monthly maximum demands during the program months.

[6] Average hourly usage is calculated as the sum of usage during the program months divided by the number of hours during the program months.

hotels, health care and services industry groups made up the majority of PG&E's DBP enrollment.

Table 2.1: DBP Enrollees by Industry group – *PG&E*

Industry Type	Count	Sum of Max kW	Sum of Mean kWh	% of Max kW	Ave. Size (kW)
1.Ag., Mining, Constr.	123	187,401	139,054	14%	1,524
2.Manufacturing	305	534,987	363,165	39%	1,754
3.Whole., Trans., Util.	178	176,356	89,826	13%	991
4.Retail	78	19,335	10,647	1%	248
5.Offices, Hotels, Health, Services	309	330,280	223,258	24%	1,069
6.Schools	41	38,604	20,013	3%	942
7.Ent, Other svcs, Govt.	92	96,343	56,712	7%	1,047
8.Other	1	287	122	0%	287
TOTAL	**1,127**	**1,383,592**	**902,796**		**1,228**

Table 2.2 shows comparable information on DBP enrollment for SCE. SCE's enrollment in DBP has expanded from 1,079 customer service accounts in 2006, 1,222 in 2007, and 1,244 in 2008, to 1,368 customer service accounts in 2009. These accounted for 1,503 MW of maximum demand. Manufacturers continued to make up more than half of the enrolled load.

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

Industry Type	Count	Sum of Max kW	Sum of Mean kWh	% of Max kW	Ave. Size (kW)
1.Ag., Mining, Constr.	36	40,942	22,713	3%	1,137
2.Manufacturing	375	793,699	483,605	53%	2,117
3.Whole., Trans., Util.	204	123,959	74,810	8%	608
4.Retail	172	85,974	52,180	6%	500
5.Offices, Hotels, Health, Services	260	197,766	117,668	13%	761
6.Schools	224	84,346	25,781	6%	377
7.Ent, Other svcs, Govt.	97	176,559	115,854	12%	1,820
TOTAL	**1,368**	**1,503,244**	**892,612**		**1,099**

Tables 2.3 and 2.4 show DBP enrollment by local capacity area for PG&E and SCE respectively.

Table 2.3: DBP Enrollees by Local Capacity Area – *PG&E*

Local Capacity Area	Count	Sum of Max kW	Sum of Mean kWh	% of Max kW	Ave. Size (kW)
Greater Bay Area	541	574,637	391,680	42%	1,062
Greater Fresno	53	54,696	33,500	4%	1,032
Humboldt	12	3,991	2,313	0%	333
Kern	52	42,366	22,932	3%	815
Northern Coast	73	47,470	25,537	3%	650
Sierra	55	25,736	12,506	2%	468
Stockton	31	17,991	8,890	1%	580
Not in any LCA	310	616,706	405,439	45%	1,989
TOTAL	**1,127**	**1,383,592**	**902,796**		**1,228**

Table 2.4: DBP Enrollees by Local Capacity Area – *SCE*

Local Capacity Area	Count	Sum of Max kW	Sum of Mean kWh	% of Max kW	Ave. Size (kW)
LA Basin	1,096	1,060,995	621,400	71%	968
Outside LA Basin	60	164,221	104,351	11%	2,737
Ventura	212	278,028	166,861	18%	1,311
TOTAL	**1,368**	**1,503,244**	**892,612**		**1,099**

Tables 2.5 and 2.6 summarize the characteristics of customer accounts that submitted a bid for at least one 2009 event for PG&E and SCE respectively. For both utilities, the manufacturing industry group had the highest share of enrolled load that submitted a bid.

Table 2.5: DBP Bidding Behavior – *PG&E*

Industry Type	# Bidders	Sum of Max kW	% of Enrolled Max kW
1.Ag., Mining, Constr.	3	5,489	3%
2.Manufacturing	29	146,033	27%
3.Whole., Trans., Util.	17	27,852	16%
4.Retail	4	1,895	10%
5.Offices, Hotels, Health, Services	25	46,329	14%
6.Schools	4	7,009	18%
7. Ent, Other svcs, Govt.	6	8,513	9%
TOTAL	**88**	**243,120**	**18%**

Table 2.6: DBP Bidding Behavior – *SCE*

Industry Type	# Bidders	Sum of Max kW	% of Enrolled Max kW
1.Ag., Mining, Constr.	15	17,929	44%
2.Manufacturing	198	541,331	68%
3.Whole., Trans., Util.	91	81,079	65%
4.Retail	33	40,782	47%
5.Offices, Hotels, Health, Services	91	79,246	40%
6.Schools	47	19,977	24%
7. Ent, Other svcs, Govt.	29	97,914	55%
TOTAL	**504**	**878,257**	**58%**

2.3 Event Days

Table 2.7 lists DBP event days for the two utilities in 2009. PG&E called only one event, a four-hour test event on August 28 that covered hours-ending 15 – 18. SCE called 15 events. The first was a four-hour test event from Noon to 4:00 p.m. All others were eight-hour events from hours-ending 13 to 18.

Table 2.7: DBP Events – 2009

Date	Day of Week	SCE	PG&E
6/4/2009	Thursday	1 (Test)	
7/15/2009	Wednesday	2	
7/17/2009	Friday	3	
7/20/2009	Monday	4	
7/22/2009	Wednesday	5	
7/27/2009	Monday	6	
7/28/2009	Tuesday	7	
8/27/2009	Thursday	8	
8/28/2009	Friday	9	1 (Test)
8/31/2009	Monday	10	
9/1/2009	Tuesday	11	
9/2/2009	Wednesday	12	
9/3/2009	Thursday	13	
9/8/2009	Tuesday	14	
9/22/2009	Tuesday	15	

3. Study Methodology

3.1 Overview

We estimated ex post hourly load impacts using regression equations applied to customer-level hourly load data. The regression equation models hourly load as a function of a set of variables designed to control for factors affecting consumers' hourly demand levels, such as:

- Seasonal and hourly time patterns (*e.g.*, year, month, day-of-week, and hour, plus various hour/day-type interactions);

- Weather (*e.g.*, cooling degree hours, including hour-specific weather coefficients);
- Event variables. A series of dummy variables was included to account for each hour of each event day, allowing us to estimate the load impacts for all hours across the event days.

The models use the level of hourly demand (kW) as the dependent variable and a separate equation is estimated for each enrolled customer. As a result, the coefficients on the event day/hour variables are direct estimates of the ex post load impacts. For example, a DBP hour 14 event coefficient of -100 would mean that the customer reduced load by 100 kWh during hour 14 of that event day relative to its normal usage in that hour. Weekends and holidays were excluded from the estimation database.[7]

3.2 Description of methods

3.2.1 Regression Model

The model shown below was separately estimated for each enrolled customer.

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

In this equation, Q_t represents the demand in hour t for a customer enrolled in DBP prior to the last event date; the *b*'s are estimated parameters; $h_{i,t}$ is a dummy variable for hour i; DBP_t is an indicator variable for program event days; CDH_t is cooling degree hours;[8] 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; $OtherEvt_t$ is equal to one in the event hours of other demand response programs in which the customer is enrolled; 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

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

[8] 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.

dummy variables for each month; $Summer_t$ is a variable indicating summer months (defined as mid-June through mid-August)[9], which is interacted with the weather and hourly profile variables; and e_t is the error term. The "morning load" variable was used in lieu of a more formal autoregressive structure in order to adjust the model to account for 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.

Separate models were estimated for each customer. The load impacts were aggregated across customer accounts as appropriate to arrive at program-level load impacts, as well as load impacts by industry group and local capacity area (LCA). In addition, a cross-section "meta-analysis" of the customer-level results is performed to assess the load impacts associated with customers participating in the TA/TI and AutoDR programs. We add load impacts across only customers who submitted bids for a given event. PG&E only called one event (a test event), which was also a CPP and BIP event day. The two-hour BIP event overlapped with the first two hours of the DBP event. For the customers enrolled in both programs, we zeroed out the DBP load impacts during the BIP hours (2 to 4 p.m.), but retained the estimated coefficients in all other hours. The CPP event hours overlapped with all of the DBP event hours. Therefore, the service accounts enrolled in CPP could not bid for the DBP event.

3.2.2 Development of Uncertainty-Adjusted Load Impacts

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

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

4. Detailed Study Findings

The primary objective of the *ex post* evaluation is to estimate the aggregate and per-customer DBP event-day load impacts for each utility. In this section we first summarize the estimated DBP load impacts for both utilities' using a metric of estimated *average hourly load impacts* by event and for the average event. We also report average hourly load impacts for the average event by industry type and local capacity area. We then

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[9] 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.

present 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 the reference loads, observed loads and estimated load impacts. The section concludes with an assessment of the effects of TA/TI and AutoDR.

On a summary level, the average event-hour load impact per enrolled customer was 48 kW for PG&E's program and 33 kW for SCE's program.

4.1 PG&E Load Impacts

4.1.1 Average Hourly Load Impacts by Industry Group and LCA

Table 4.1 summarizes average hourly DBP load impacts at the program level and by industry group for PG&E’s test event, which occurred on August 28. While DBP load impacts were estimated from the individual customer regressions of only those enrolled customers who submitted a bid on the test event, the reference loads and observed loads shown in the table reflect all customers enrolled in DBP. Across the four event hours, the average hourly load impact was 54 MW, or 5.6 percent of enrolled load.[10] The Manufacturing industry group accounted for the largest share of the load impacts.

Table 4.2 summarizes load impacts by local capacity area, showing that the highest share of the load impacts came from outside of the seven LCAs.

Table 4.1: Average Hourly Load Impacts – PG&E DBP, *by Industry Group*

Industry Group	Count	Estimated Reference Load (kW)	Observed Load (kW)	Estimated Load Impact (kW)	% LI
Agriculture, Mining, & Construction	123	130,777	130,188	588	0.4%
Manufacturing	304	345,861	303,746	42,114	12.2%
Wholesale, Transportation, & Other Utilities	177	71,156	66,300	4,856	6.8%
Retail Stores	78	14,561	14,266	295	2.0%
Offices, Hotels, Health, Services	309	300,270	295,417	4,853	1.6%
Schools	41	31,715	31,414	301	0.9%
Entertainment, Other Services, Government	92	76,510	75,449	1,061	1.4%
Other or Unknown	1	112	112	0	0.0%
Total	**1,125**	**970,962**	**916,892**	**54,070**	**5.6%**

[10] As noted below, this average hourly load impact value is likely artificially high due to the large two-hour load reductions that joint DBP/BIP customers carried into the DBP event hours after the end of a contemporaneous BIP event.

Table 4.2: Average Hourly Load Impacts – PG&E DBP, *by LCA*

Local Capacity Area	Count	Estimated Reference Load (kW)	Observed Load (kW)	Estimated Load Impact (kW)	% LI
Greater Bay Area	540	496,040	487,534	8,506	1.7%
Greater Fresno	53	39,424	38,413	1,011	2.6%
Humboldt	12	1,317	825	492	37.4%
Kern	52	17,606	14,150	3,456	19.6%
Northern Coast	73	31,192	31,168	24	0.1%
Sierra	55	12,764	12,795	-31	-0.2%
Stockton	31	7,674	7,674	0	0.0%
Not in any LCA	309	364,945	324,332	40,613	11.1%
Total	**1,125**	**970,962**	**916,892**	**54,070**	**5.6%**

4.1.2 Hourly Load Impacts

Table 4.3 presents hourly PG&E DBP load impacts at the program level in the manner required by the Protocols. DBP load impacts were estimated from the individual customer regressions of only those enrolled customers who submitted a bid on the test event. However, the reference loads and observed loads in the table reflect all customers enrolled in DBP. Hourly load impacts ranged from 4.8 to 104.7 MW, with the high end representing approximately 10 percent of the total DBP reference load for enrolled customers. The very large variation in load impacts (and reference loads) is due to the overlap with the BIP event. Service accounts enrolled in both BIP and DBP tended to submit bids for only the last two hours of the DBP event. The very large load response that they exhibited during the BIP event hours was carried forward into the remaining DBP event hours. In order to remove the effect of the BIP event on estimated DBP load impacts, we set those load impacts to zero during hours 15 and 16 for the BIP service accounts.[11] The level of load impact that remains in those hours once the BIP customers are removed is rather small, at approximately 4 MW, or 0.6 percent of the reference load.

[11] Because reference loads are estimated by adding the load impact to the observed load, our method had the effect of reducing the reference loads by the same amount as the load impacts during the BIP event hours.

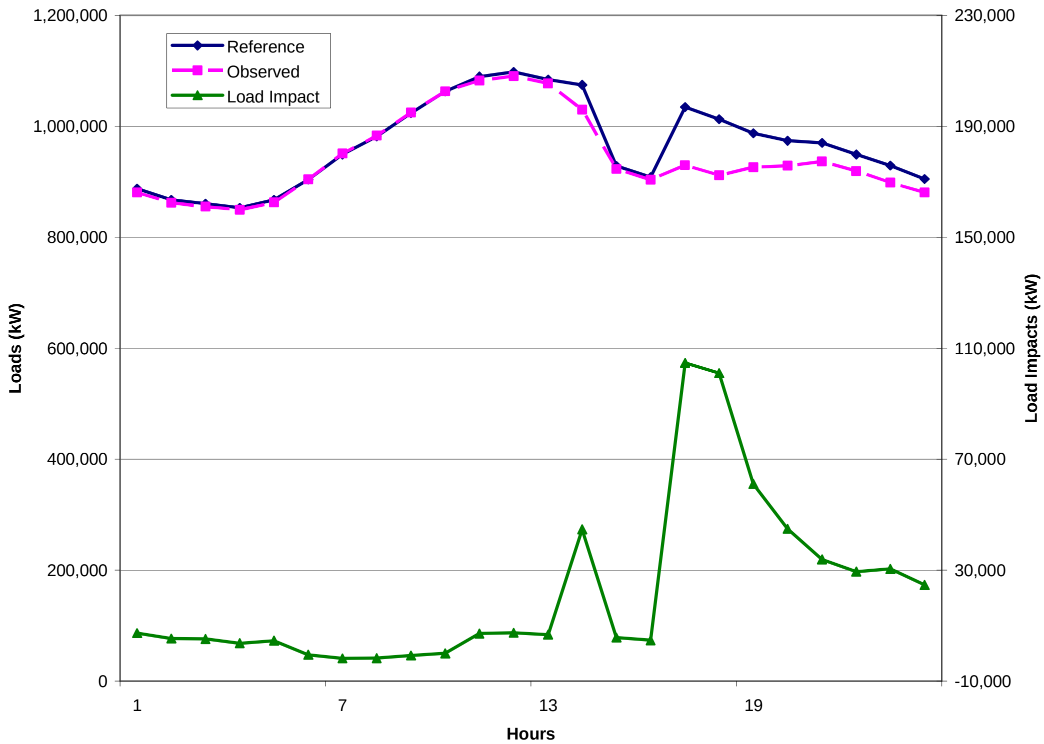
Table 4.3: DBP Hourly Load Impacts for August 28, 2009 Event Day – *PG&E*

Hour Ending	Estimated Reference Load (kWh/hour)	Observed Event Day Load (kWh)	Estimated Load Impact (kWh/hour)	Weighted Average Temperature (°F)	Uncertainty Adjusted Impact (kWh/hr)- Percentiles				
					10th%ile	30th%ile	50th%ile	70th%ile	90th%ile
1	887,575	880,253	7,322	71	900	4,694	7,322	9,950	13,745
2	867,400	862,035	5,365	70	-1,384	2,603	5,365	8,127	12,114
3	860,490	855,289	5,201	69	-1,429	2,488	5,201	7,914	11,831
4	853,117	849,423	3,694	68	-2,851	1,016	3,694	6,373	10,240
5	867,006	862,368	4,638	67	-2,080	1,889	4,638	7,387	11,356
6	903,739	904,189	-450	67	-7,275	-3,242	-450	2,343	6,375
7	949,012	950,791	-1,779	66	-8,348	-4,467	-1,779	909	4,790
8	981,232	982,908	-1,676	67	-7,910	-4,227	-1,676	875	4,558
9	1,023,698	1,024,473	-775	72	-7,378	-3,477	-775	1,927	5,829
10	1,062,871	1,062,854	17	77	-6,489	-2,645	17	2,679	6,523
11	1,089,431	1,082,227	7,204	82	797	4,582	7,204	9,826	13,611
12	1,097,728	1,090,293	7,435	86	1,233	4,897	7,435	9,972	13,636
13	1,083,909	1,077,117	6,792	90	661	4,283	6,792	9,300	12,923
14	1,074,631	1,029,915	44,716	93	38,416	42,139	44,716	47,294	51,016
15	928,461	922,729	5,732	96	4,782	5,343	5,732	6,121	6,682
16	908,280	903,487	4,794	96	3,879	4,419	4,794	5,168	5,708
17	1,034,521	929,780	104,741	95	98,539	102,203	104,741	107,278	110,942
18	1,012,584	911,571	101,013	93	94,877	98,502	101,013	103,524	107,149
19	987,143	926,054	61,088	91	54,962	58,581	61,088	63,595	67,215
20	973,653	928,702	44,951	88	38,551	42,332	44,951	47,570	51,351
21	970,268	936,420	33,848	84	27,206	31,130	33,848	36,566	40,490
22	948,880	919,348	29,533	82	22,450	26,634	29,533	32,431	36,615
23	929,026	898,580	30,446	79	23,720	27,694	30,446	33,199	37,173
24	905,134	880,449	24,685	77	18,097	21,989	24,685	27,380	31,272
	Reference Energy Use (kWh)	Estimated 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	23,199,790	22,671,254	528,535	184.4	n/a	n/a	n/a	n/a	n/a

The top portion of Figure 4.1 illustrates the reference load (net of the BIP load reduction) and observed load for the DBP test event. The lower portion of the figure displays the estimated DBP load impacts (which are labeled on the right y-axis).

The full set of tables required by the Protocols, including tables for each local capacity area, are in the Excel file attached as an Appendix to this report.

Figure 4.1: DBP Load Impacts – *PG&E*



4.2 SCE Load Impacts

4.2.1 Average Hourly Load Impacts by Industry Group and LCA

Table 4.4 summarizes average hourly reference loads and load impacts at the program level for each of SCE's fifteen DBP events.[12] Across all events, the average hourly load impact was approximately 41.6 MW. The load impacts showed some variation across event days, with a low if 25.5 MW, a high of 58.8 MW, and a standard deviation of nearly 10 MW. On average, the load impacts were about 4.2 percent of the total reference load.

Table 4.5 compares the bid quantities to the estimated load impacts for each event. Across all events, the bid amount averaged approximately 130 MW, while the estimated average hourly load impact was 41.6 MW. The average bid realization rate (estimated load impacts as a percentage of bid amounts) across all event hours was 32.1 percent.

[12] As for PG&E, the reference loads and observed loads represent all enrolled DBP customer accounts, while the estimated load reductions were estimated only for the accounts that submitted bids for a given event.

Table 4.4: Average Hourly Load Impacts by Event, *SCE*

Event	Date	Day of Week	Estimated Reference Load (kW)	Observed Load (kW)	Estimated Load Impact (kW)	% LI
1	6/4/2009	Thursday	888,963	831,816	57,147	6.4%
2	7/15/2009	Wednesday	969,356	922,728	46,628	4.8%
3	7/17/2009	Friday	941,613	898,675	42,938	4.6%
4	7/20/2009	Monday	974,299	938,316	35,983	3.7%
5	7/22/2009	Wednesday	991,408	955,491	35,918	3.6%
6	7/27/2009	Monday	969,916	934,833	35,084	3.6%
7	7/28/2009	Tuesday	958,681	931,133	27,548	2.9%
8	8/27/2009	Thursday	1,054,271	1,005,388	48,883	4.6%
9	8/28/2009	Friday	1,016,918	991,415	25,503	2.5%
10	8/31/2009	Monday	1,042,542	1,001,955	40,587	3.9%
11	9/1/2009	Tuesday	1,057,570	1,021,787	35,783	3.4%
12	9/2/2009	Wednesday	1,070,370	1,033,226	37,145	3.5%
13	9/3/2009	Thursday	1,083,250	1,029,452	53,798	5.0%
14	9/8/2009	Tuesday	984,116	941,436	42,679	4.3%
15	9/22/2009	Tuesday	1,000,396	941,611	58,785	5.9%
		Average	**1,000,245**	**958,617**	**41,627**	**4.2%**
		Std. Dev.	**53,794**	**55,422**	**9,945**	**1.0%**

Table 4.5: Average Hourly Bid Realization Rates by Event, *SCE*

Event	Date	Day of Week	Average Bid Quantity (kW)	Estimated Load Impact (kW)	LI as % of Bid Amount
1	6/4/2009	Thursday	189,828	57,147	30.1%
2	7/15/2009	Wednesday	128,093	46,628	36.4%
3	7/17/2009	Friday	107,497	42,938	39.9%
4	7/20/2009	Monday	110,965	35,983	32.4%
5	7/22/2009	Wednesday	115,732	35,918	31.0%
6	7/27/2009	Monday	125,719	35,084	27.9%
7	7/28/2009	Tuesday	125,121	27,548	22.0%
8	8/27/2009	Thursday	122,728	48,883	39.8%
9	8/28/2009	Friday	118,033	25,503	21.6%
10	8/31/2009	Monday	130,981	40,587	31.0%
11	9/1/2009	Tuesday	121,654	35,783	29.4%
12	9/2/2009	Wednesday	130,740	37,145	28.4%
13	9/3/2009	Thursday	130,831	53,798	41.1%
14	9/8/2009	Tuesday	140,563	42,679	30.4%
15	9/22/2009	Tuesday	149,594	58,785	39.3%
		Average	**129,872**	**41,627**	**32.1%**

Tables 4.6 and 4.7 summarize average hourly load impacts for the average event (excluding the test event) by industry group and LCA. Manufacturing service accounts accounted for the largest shares of the load impacts. By region, the highest share of the average load impact came from the LA Basin.

Table 4.6: Average Hourly Load Impacts (kW) – SCE DBP, *by Industry Group*

Industry Group	Count	Estimated Reference Load (kW)	Observed Load (kW)	Estimated Load Impact (kW)	% LI
Agriculture, Mining, & Construction	32	21,450	21,310	140	0.7%
Manufacturing	360	510,376	477,467	32,909	6.4%
Wholesale, Transportation, & Other Utilities	189	73,699	69,004	4,695	6.4%
Retail Stores	136	58,462	57,902	560	1.0%
Offices, Hotels, Health, Services	246	143,530	141,711	1,818	1.3%
Schools	223	43,163	42,908	255	0.6%
Entertainment, Other Services, Government	94	147,098	146,827	272	0.2%
Total	**1,280**	**997,779**	**957,129**	**40,650**	**4.1%**

Table 4.7: Average Hourly Load Impacts – SCE DBP, *by LCA*

Local Capacity Area	Count	Estimated Reference Load (kW)	Observed Load (kW)	Estimated Load Impact (kW)	% LI
LA Basin	1,018	695,791	661,894	33,897	4.9%
Outside LA Basin	54	108,783	104,576	4,207	3.9%
Ventura	208	193,204	190,659	2,546	1.3%
Total	**1,280**	**997,779**	**957,129**	**40,650**	**4.1%**

4.2.2 Hourly Load Impacts

Table 4.8 presents hourly load impacts at the program level for the average DBP event in the manner required by the Protocols. The reference loads and observed loads in the table reflect all customers enrolled in DBP. Load impacts reflect only customers that submitted bids. Hourly load impacts for the average event range from 35.1 MW (in the last hour of the event) to 44.2 MW. These load impacts represent about 4 percent of the total enrolled DBP reference load.

Table 4.8: DBP Hourly Load Impacts for Average Event Day, *SCE*

Hour Ending	Estimated Reference Load (kWh/hour)	Observed Event Day Load (kWh)	Estimated Load Impact (kWh/hour)	Weighted Average Temperature (°F)	Uncertainty Adjusted Impact (kWh/hr)- Percentiles				
					10th%ile	30th%ile	50th%ile	70th%ile	90th%ile
1	829,230	830,086	-856	72	-8,147	-3,839	-856	2,128	6,436
2	820,826	822,365	-1,538	71	-8,931	-4,563	-1,538	1,486	5,854
3	811,013	812,941	-1,928	70	-9,326	-4,955	-1,928	1,100	5,471
4	811,230	813,962	-2,732	69	-10,127	-5,758	-2,732	295	4,664
5	834,800	838,038	-3,238	68	-10,615	-6,257	-3,238	-220	4,139
6	888,017	891,834	-3,817	68	-11,197	-6,837	-3,817	-798	3,562
7	939,267	943,288	-4,020	67	-11,404	-7,041	-4,020	-999	3,363
8	989,063	995,152	-6,089	67	-13,467	-9,108	-6,089	-3,069	1,290
9	1,027,626	1,031,484	-3,858	69	-11,254	-6,885	-3,858	-832	3,538
10	1,058,809	1,059,800	-992	73	-8,371	-4,011	-992	2,028	6,387
11	1,071,468	1,070,008	1,460	77	-5,900	-1,551	1,460	4,472	8,820
12	1,072,565	1,059,835	12,730	81	5,368	9,718	12,730	15,743	20,093
13	1,051,549	1,009,009	42,540	83	35,185	39,530	42,540	45,549	49,894
14	1,055,440	1,011,211	44,228	85	36,880	41,221	44,228	47,235	51,576
15	1,047,697	1,005,107	42,590	86	35,250	39,586	42,590	45,593	49,929
16	1,024,290	983,143	41,148	87	33,800	38,141	41,148	44,154	48,495
17	996,808	956,623	40,185	87	32,843	37,181	40,185	43,190	47,528
18	963,693	923,564	40,129	86	32,786	37,124	40,129	43,133	47,471
19	925,819	886,586	39,233	85	31,890	36,228	39,233	42,238	46,577
20	916,935	881,787	35,148	83	27,798	32,141	35,148	38,155	42,498
21	923,740	901,440	22,300	80	14,951	19,293	22,300	25,307	29,648
22	904,285	888,176	16,109	77	8,762	13,103	16,109	19,115	23,455
23	878,432	866,819	11,613	75	4,254	8,602	11,613	14,624	18,971
24	857,917	850,034	7,883	74	503	4,863	7,883	10,903	15,263
	Reference Energy Use (kWh)	Estimated 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	22,700,520	22,332,290	368,228	97.5	n/a	n/a	n/a	n/a	n/a

The top portion of Figure 4.2 illustrates the hourly reference load and observed load for the average DBP event. The bottom portion of Figure 4.2 displays the estimated hourly load impacts (scale is presented on the right y-axis) for the average DBP event. Figure 4.3 shows the variability of estimated load impacts across events.

Figure 4.2: DBP Load Impacts – *SCE*

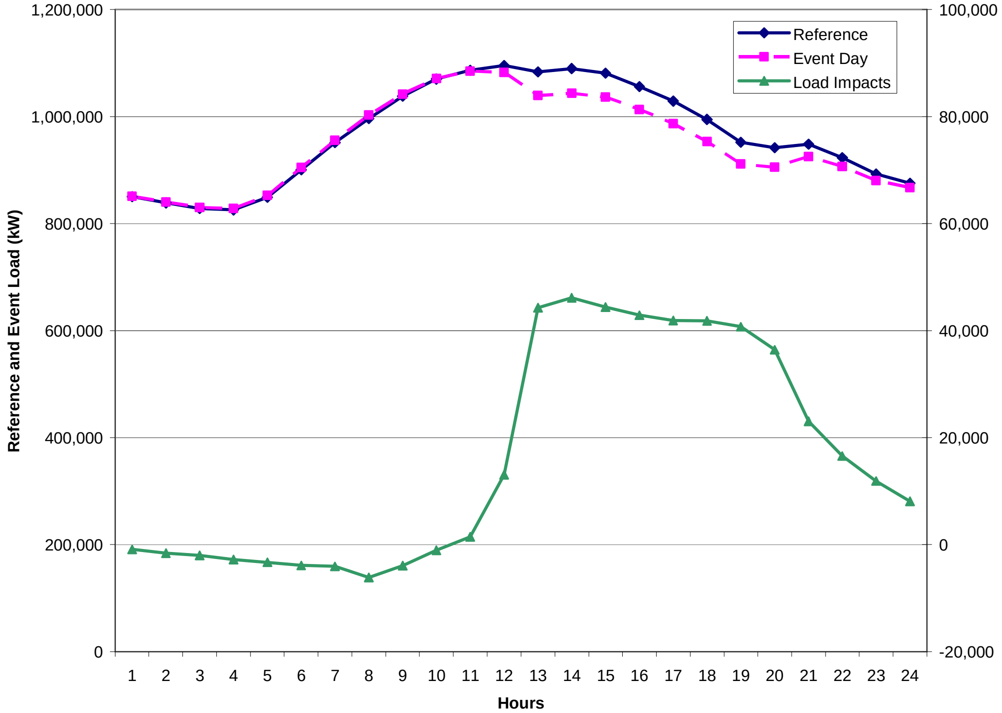
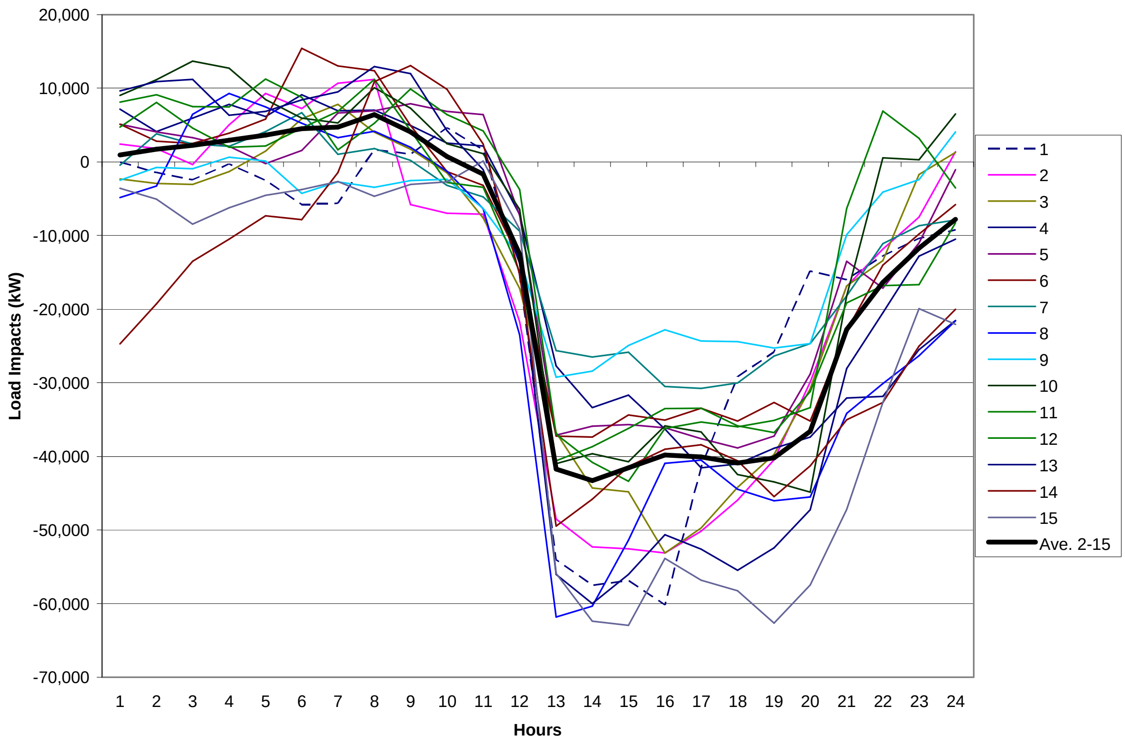


Figure 4.3: Hourly Load Impacts by Event – *SCE DBP*



4.3 Effect of TA/TI and AutoDR on Load Impacts

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

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

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

For each utility and incentive program, we present two tables of information. The first table contains the overall average hourly load impacts provided by the service accounts that participated in TA/TI or AutoDR. The second table compares 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 conducted comparisons of load impacts within these highly disaggregated industry groups. Where a comparison at this level of disaggregation was not possible, we compared 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 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

According to data provided by PG&E, 13 service accounts that were enrolled in DBP and submitted a bid for the August 28th event participated in the AutoDR program.[13]

Table 4.9 shows the event-specific load impacts for the AutoDR participants. On average, the AutoDR customers provided 1.5 MW of load reduction, or 8.8 percent of their reference load.

Table 4.9: Average Hourly Load Impacts by Event, *PG&E AutoDR*

Event Date	Number of SAIDs	Estimated Reference Load (kW)	Observed Load (kW)	Estimated Load Impact (kW)	% Load Impact
8/28/2009	13	16,678	15,204	1,474	8.8%

Table 4.10 shows the comparisons of load impacts within similar industry classifications. Because the analysis excludes non-bidders and BIP event participants, only 47 SAIDs remained for these comparisons. Therefore, we were only able to find a reasonable set of comparison accounts for two of the eight industry groups. The results across those two groups are inconclusive, with one of the two showing higher load impacts for the AutoDR accounts.

Table 4.10: Incremental AutoDR Load Impacts by Industry Group, *PG&E*

NAICS Code	NAICS Description	Basis of Comparison	Percentage Load Impact		Number of Events	
			No AutoDR	AutoDR	No AutoDR	AutoDR
221112	Hydroelectric Power Generation	No Comparables	n/a	n/a	n/a	1
424410	General Line Grocery Merchant Wholesalers	No Comparables	n/a	n/a	n/a	1
442110	Furniture Stores	No Comparables	n/a	n/a	n/a	1
452111	Department Stores	No Comparables	n/a	n/a	n/a	1
452112	Discount Department Stores	No Comparables	n/a	n/a	n/a	1
518210	Data Processing, Hosting, and Related Services	2-digit NAICS	1.2%	4.5%	2	1
551114	Corporate Managing Offices	6-digit NAICS	7.6%	1.8%	2	3
921190	Other General Government Support	No Comparables	n/a	n/a	n/a	4

[13] Three additional service accounts who participated in AutoDR submitted bids on the event day. However, they were excluded from the analysis because of their dual enrollment with BIP.

SCE

Table 4.11 shows the DBP load impacts provided by SCE's TA/TI service accounts for each event. An average of 19 of SCE's DBP service accounts participated in TA/TI. The load impacts vary dramatically across events. The variability is largely due to one service account that sometimes provides essentially zero load impacts, but for other events provides 15 to 19 MW of load response. The load impacts in the absence of this customer average 1.9 MW, or 12.7 percent of the remaining reference load.

Table 4.11: Average Hourly 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
6/4/2009	18	36,687	16,146	20,541	56.0%
7/15/2009	16	33,820	30,459	3,361	9.9%
7/17/2009	15	31,759	29,097	2,662	8.4%
7/20/2009	14	28,110	28,020	90	0.3%
7/22/2009	19	33,913	32,919	994	2.9%
7/27/2009	17	30,530	29,351	1,179	3.9%
7/28/2009	18	31,901	30,455	1,446	4.5%
8/27/2009	19	32,677	12,235	20,443	62.6%
8/28/2009	20	35,372	33,260	2,111	6.0%
8/31/2009	21	35,277	16,442	18,835	53.4%
9/1/2009	20	36,044	33,839	2,204	6.1%
9/2/2009	20	34,844	35,292	-448	-1.3%
9/3/2009	19	32,368	13,477	18,891	58.4%
9/8/2009	22	38,269	18,504	19,765	51.6%
9/22/2009	21	38,570	19,139	19,430	50.4%
Average	**19**	**34,009**	**25,242**	**8,767**	**25.8%**

Table 4.12 shows load impact comparisons by industry group. The load impact differences between TA/TI participants and non-participants vary dramatically across industry groups. For SIC 4941 (Water Supply), TA/TI accounts have percentage load impacts that are 83 percentage points higher than non-TA/TI accounts. At the other extreme, percentage load impacts for TA/TI accounts in the Industrial Gases SIC (2813) are 29 percentage points *lower* than those of non-TA/TI SAIDs.

Table 4.12: Incremental TA/TI Load Impacts by Industry Group, *SCE*

SIC Code	SIC Description	Basis of Comparison	Percentage Load Impact		Number of Events	
			No TA/TI	TA/TI	No TA/TI	TA/TI
2026	Fluid Milk	4-digit SIC	-5.2%	1.0%	29	28
2813	Industrial Gases	4-digit SIC	60.0%	30.7%	56	34
2834	Pharmaceutical Preparations	Same Customer	-1.0%	0.6%	12	24
3691	Storage Batteries	2-digit SIC	0.0%	24.0%	376	17
4941	Water Supply	4-digit SIC	7.9%	91.3%	485	2
5072	Hardware	2-digit SIC	2.1%	17.9%	154	30
5311 & 5318	Department Stores	2-digit SIC	1.4%	3.6%	124	39
5411	Grocery Stores	4-digit SIC	0.6%	14.3%	58	8
5912	Drug Stores	No Comparables	n/a	n/a	n/a	15
6512	Operators of Non-Residential Buildings	4-digit SIC	10.1%	24.1%	360	31
6514	Operators of Non-Apartment Dwellings	No Comparables	n/a	n/a	n/a	30
7011	Hotels and Motels	4-digit SIC	1.5%	13.3%	291	6
8011	Offices of Medical Doctors	4-digit SIC	-1.0%	-1.3%	88	15

Table 4.13 shows the total DBP load impacts for SCE's AutoDR participants. The percentage load impacts are quite variable across events, ranging from 3.7 to 46.0 percent. On average, the AutoDR participants provide 1.4 MW of load impact.

Table 4.13: Average Hourly AutoDR Load Impacts by Event, *SCE*

Event Date	Number of SAIDs	Estimated Reference Load (kW)	Observed Load (kW)	Estimated Load Impact (kW)	% Load Impact
6/4/2009	7	2,767	2,584	183	6.6%
7/15/2009	8	3,868	3,279	589	15.2%
7/17/2009	7	3,221	2,967	254	7.9%
7/20/2009	8	5,191	3,468	1,723	33.2%
7/22/2009	9	6,354	4,090	2,264	35.6%
7/27/2009	9	5,530	4,110	1,420	25.7%
7/28/2009	9	5,652	5,443	208	3.7%
8/27/2009	8	5,751	5,601	151	2.6%
8/28/2009	9	6,508	4,096	2,412	37.1%
8/31/2009	11	7,117	5,463	1,655	23.3%
9/1/2009	9	6,036	4,120	1,916	31.7%
9/2/2009	8	5,906	3,187	2,719	46.0%
9/3/2009	11	8,276	5,685	2,591	31.3%
9/8/2009	10	5,551	4,580	971	17.5%
9/22/2009	12	7,411	5,800	1,611	21.7%
Average	**9**	**5,676**	**4,298**	**1,378**	**24.3%**

Table 4.14 shows the load impact comparisons by industry group. Two of the groups (SIC 3069, or Fabricated Rubber Products; and SIC 3691, or Storage Batteries) showed much higher percentage load impacts for AutoDR participants. SIC 2834 (Pharmaceutical Preparations) provided the opposite outcome, for which the load impacts of AutoDR participants were 17 percentage points lower than those of non-participants.

Table 4.14: Incremental AutoDR Load Impacts by Industry Group, *SCE*

SIC Code	SIC Description	Basis of Comparison	Percentage Load Impact		Number of Events	
			No AutoDR	AutoDR	No AutoDR	AutoDR
2834	Pharmaceutical Preparations	4-digit SIC	-1.0%	-18.0%	12	4
3069	Fabricated Rubber Products	2-digit SIC	1.4%	46.2%	438	10
3691	Storage Batteries	2-digit SIC	0.0%	60.5%	376	13
5211	Lumber Dealers	No Comparables	n/a	n/a	n/a	5
5712	Furniture Stores	4-digit SIC	-1.1%	7.6%	15	43
6512	Operators of Non-Residential Buildings	4-digit SIC	10.1%	5.4%	360	60

5. Baseline Comparisons

5.1 Objectives

One of the objectives of the DBP ex-post load impact evaluation was to compare program measurements of load impacts (*i.e.*, using the current 3-in-10 baseline method) with the upcoming 10-in-10 baseline with weather adjustment, the unadjusted 10-in-10 baseline, and the econometric estimates of load impacts developed in this impact evaluation. To achieve that objective, we used customer-level load data to calculate event-day baseline loads for DBP bidders at PG&E and SCE using the following methods:

1. The 3-in-10 method currently used in the program;
2. The 10-in-10 method, unadjusted for pre-event load levels;
3. The 10-in-10 method with an adjustment for pre-event load levels, where the adjustment factor takes the form of the ratio of the average hourly usage in the four hours prior to the event to the average over the same hours from the 10 weekdays from which the 10-in-10 baseline is calculated, and the adjustment is limited to no more than 20 percent.

We then compared each of those baselines to the estimated baseline load implied by the customer-specific regression models developed in the course of the DBP load impact evaluation. The baseline implied by the regression model for a particular customer was derived by adding the estimated hourly load impact coefficients from the regression equation to that customer's *observed load* during the event hours.[14] For example, if a customer's observed load during an event was 800 kW in each hour, and the estimated load impact coefficients were 200 kW in each hour of the event, then the implied reference, or baseline, load would be the sum of the two values, or 1,000 kW per hour. That reference load then becomes the baseline load to which the alternative program baseline loads are compared.

To examine potential differences in baseline performance by customer type, customers were classified into one of three categories—*Industrial-type* customers (which included Industry groups 1, 2, and 3), who are assumed to be not particularly weather sensitive; *Commercial-type* customers (Industry groups 4, 5, and 7), who are presumed to be weather sensitive; and Schools (Industry group 6), whose load patterns often vary during summer months due to vacation schedules for which information is often not available.

5.2 Measures of baseline performance

Performance of the alternative baseline methods was measured primarily by two statistics that have been used in previous baseline studies. Baseline **accuracy** (relative to the regression-based baseline) was measured using the *relative root mean square error* statistic (RRMSE, sometimes referred to as the Theil U-statistic). This statistic measures the degree of difference, or error, regardless of sign, between two data series, which in this case are the alternative baselines and the regression-based baseline. This statistic is nominally bounded by 0 and 1, with values closer to 0 indicating greater accuracy. Since the root-mean squared *errors* are normalized by the root-mean squared *load levels*, the resulting statistic is a normalized, or percentage measure of accuracy relative to the true baseline. For example, a value of 5 percent indicates an average 5 percent error in the baseline (or difference between an alternative program baseline and the regression-based baseline) relative to its mean value.

The formula for this statistic is the following:

$$U\text{-}statistic = [(1/n) \sum (e_h)^2]^{1/2} / [(1/n) \sum (L^A_h)^2]^{1/2},$$

where in this case

e_h = $(L^A_h - L^P_h)$,
L^A_h is the regression-based baseline load,
L^P_h is one of the alternative *predicted* (program) baseline loads,
n is the total number of customer event days and hours, and the sum is across event days and hours, for each sub-group of customers (*e.g.*, by industry type).

Bias was measured using the *median percent error*, or difference, where the percent error is defined as the *difference* between the "true" baseline load (in this case the regression-based baseline) and an alternative estimate of the baseline load, divided by the *level* of

[14] Except for regression errors, this calculation is equivalent to simulating the load on the event day using the estimated regression coefficients, with explanatory values for all variables inserted for the event day, and the event variables "turned off."

the true baseline. Using this convention, positive errors indicate *downward bias* (*i.e.*, the true baseline exceeds the estimated baseline), and negative errors indicate *upward bias* (*i.e.*, the estimated baseline exceeds the true baseline).

The median percent error statistic is the median value of all of the percent errors calculated across customers and event hours, for each industry type. This statistic indicates the extent to which a given baseline method tends to *over-state* or *under-state* the true baseline. While the median statistic serves to indicate the *typical* bias tendency, examining the *distribution* of percent errors provides greater insight into the full range of differences in the alternative baselines. Thus, we also show *deciles* of the distribution of percent errors (where the value that determines the 50th percentile is the median value of the distribution). In some cases, we also illustrate the complete distributions across all customer accounts in the three customer groups (*e.g.*, by industry type) of each customer's median percent errors for alternative baseline methods.

5.3 Data

For PG&E's DBP test event, the baseline differences were calculated for the four event hours (HE 15 – 18) for 47 customer accounts that submitted bids for the event and were not BIP participants (since BIP participants had large load impacts that were unrelated to the DBP event, as described in Section 4). For SCE, the differences were calculated for each of the eight hours (HE 13 – 20) of each of the 14 events in which a customer submitted a bid[15]. Approximately 500 customer accounts submitted bids for at least one event.

5.4 Results

5.4.1 PG&E DBP

Table 5.1 summarizes the *accuracy* results for the alternative baselines compared to the regression-based baseline, for each of the industry groups. Figure 5.1 presents the same results in graphical form. The results indicate that in the case of the PG&E DBP test event in 2009, the program baselines differed most from the regression-based baseline for the relatively few school accounts, with average differences ranging from 24.4 percent for the unadjusted 3-in-10 baseline to 11 percent for the *adjusted* 10-in-10 baseline. Differences between baselines were smallest for the commercial-type customer accounts, ranging from 6.6 percent for the unadjusted 3-in-10 to 5.6 percent for the adjusted 10-in-10 version.

[15] The four-hour test event was not included in the analysis.

Table 5.1: Accuracy of Alternative Baselines – PG&E DBP (Relative Root Mean Square Error)

Customer Type	Customer Event-hours	Unadjusted 3-in-10	Unadjusted 10-in-10	Adjusted 10-in-10
Industrial	52	8.5%	10.7%	10.4%
Commercial	120	6.6%	10.1%	5.6%
Schools	16	24.4%	19.4%	11.0%
TOTAL	188	8.8%	10.9%	7.0%

Figure 5.1: Accuracy of Alternative Baselines – PG&E DBP (*Relative Root Mean Square Error*)

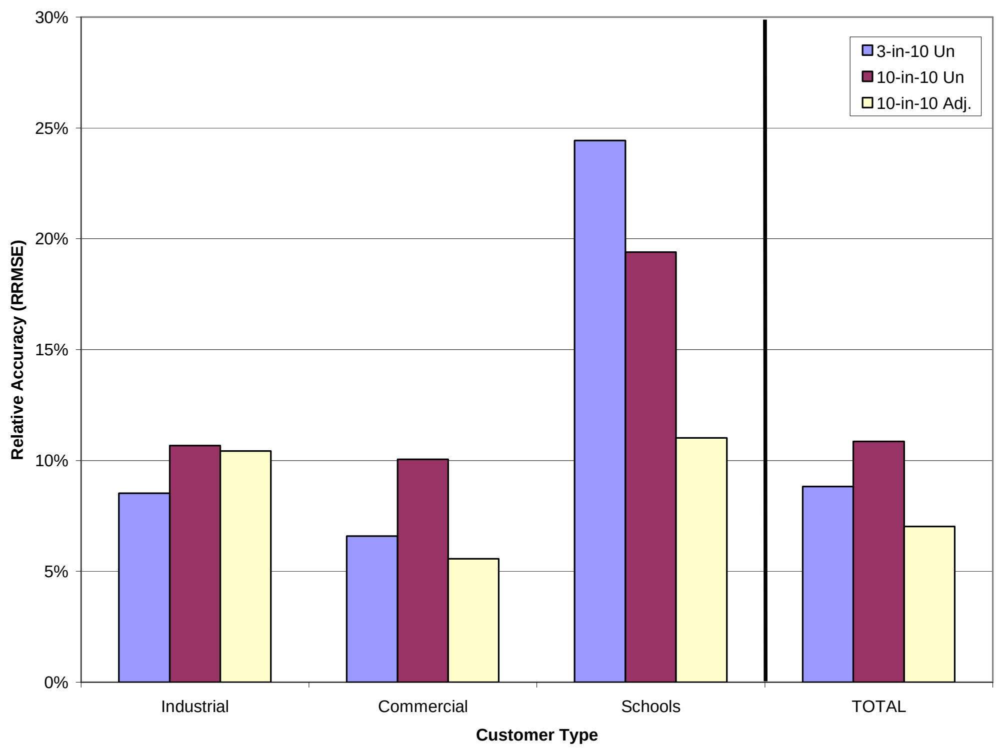


Table 5.2 presents results for the typical *bias* of the alternative baselines relative to the regression-based baseline. The unadjusted 3-in-10 results suggest that the current program baseline typically *over-states* load impacts for the industrial and schools categories (negative values), while *under-stating* load impacts for commercial customers (relative to the regression-based estimate). The results for the adjusted 10-in-10 baselines indicate a reduction in the typical biases for industrial and commercial accounts, but not for schools, which go from a 9 percent over-statement to a 10 percent under-statement. Additional insight into the range of baseline differences across customer accounts is provided in the tables and figures below.

Table 5.2: Bias of Alternative Baselines – PG&E DBP
(*Median Percent Difference*)

Customer Type	Customer Event-hours	Unadjusted 3-in-10	Unadjusted 10-in-10	Adjusted 10-in-10
Industrial	52	-3.6%	4.8%	1.0%
Commercial	120	2.9%	7.9%	-0.6%
Schools	16	-8.6%	-1.3%	10.4%
TOTAL	188	1.0%	6.7%	-0.2%

Figure 5.2: Bias of Alternative Baselines – PG&E DBP
(*Median Percent Difference*)

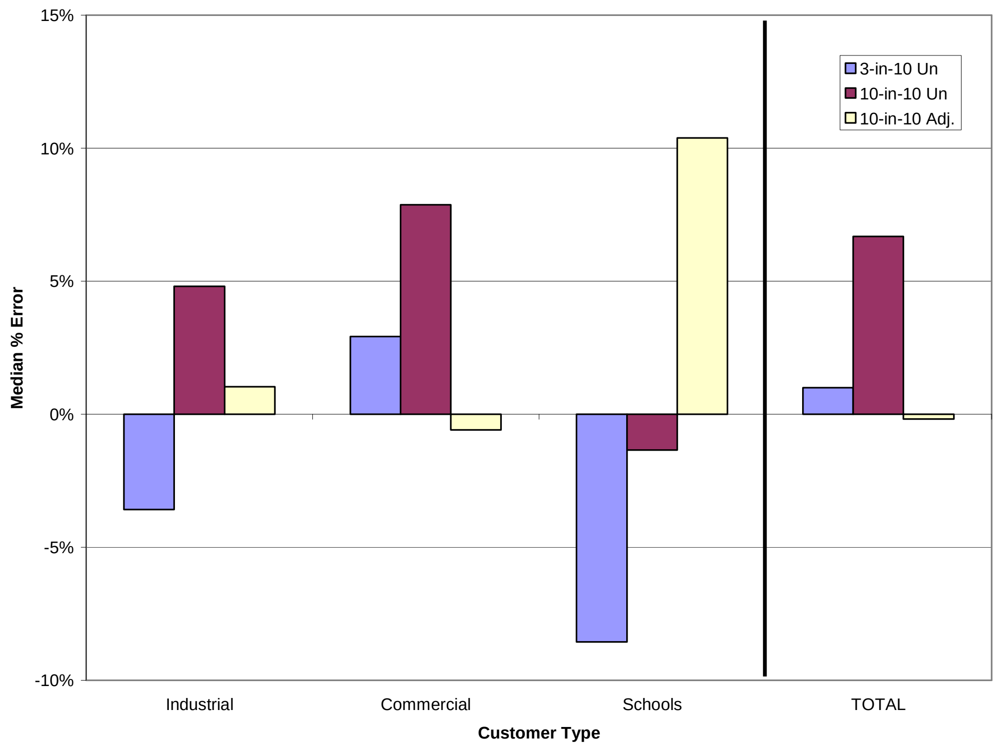


Table 5.3 expands on the single median value of the percent differences between the three alternative baselines and the regression-based values by providing values that determine *deciles* of the percent differences. That is, ten percent of the percent error values across customers and event hours fall within each decile. Nine values are provided, each representing boundary values between deciles of values. The 50 percentile values represent the median values of the distributions. Thus, for example, the median percent difference for the unadjusted 3-in-10 baseline for the industrial-type customers is negative 3.6 percent, indicating a modest "typical" over-statement relative to the regression-based baseline. However, the 30th percentile value indicates that 30 percent of the over-statements exceed 16 percent, while the 70th percentile value indicates that another thirty percent of the values reflect *under-statements* that exceed 4.5 percent.

The distributions for the commercial-type customer accounts are generally “tighter,” with the exception of a few outliers.

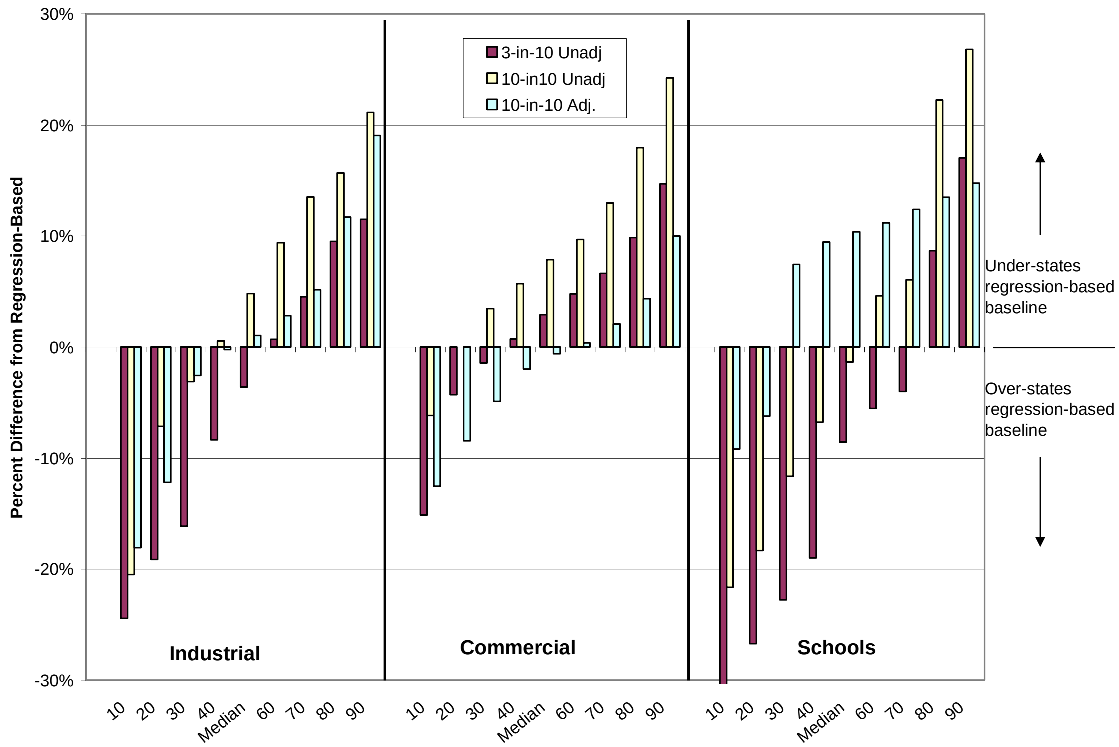
Table 5.3: Percentiles of Relative Errors of Alternative Baselines – ***PG&E DBP***

Customer Type	Percentile	Customer Event-hours	Unadjusted 3-in-10	Unadjusted 10-in-10	Adjusted 10-in-10
Industrial		52			
	10		-24.4%	-20.5%	-18.0%
	20		-19.1%	-7.1%	-12.2%
	30		-16.1%	-3.1%	-2.6%
	40		-8.3%	0.5%	-0.2%
	Median		-3.6%	4.8%	1.0%
	60		0.7%	9.4%	2.8%
	70		4.5%	13.5%	5.2%
	80		9.5%	15.7%	11.7%
	90		11.5%	21.1%	19.1%
Commercial		120			
	10		-15.1%	-6.2%	-12.5%
	20		-4.3%	0.0%	-8.4%
	30		-1.4%	3.5%	-4.9%
	40		0.8%	5.7%	-2.0%
	Median		2.9%	7.9%	-0.6%
	60		4.8%	9.7%	0.4%
	70		6.6%	13.0%	2.1%
	80		9.9%	18.0%	4.4%
	90		14.7%	24.3%	10.0%
Schools		16			
	10		-31.8%	-21.6%	-9.2%
	20		-26.7%	-18.3%	-6.2%
	30		-22.8%	-11.6%	7.4%
	40		-19.0%	-6.8%	9.5%
	Median		-8.6%	-1.3%	10.4%
	60		-5.5%	4.6%	11.2%
	70		-4.0%	6.1%	12.4%
	80		8.7%	22.3%	13.5%
	90		17.1%	26.8%	14.8%

Figure 5.3 illustrates the decile values graphically for the three customer types. At least three features of the distributions of percent differences for the alternative baselines stand out. First, for all three industry types the decile values for the 3-in-10 baselines tend more toward the negative direction (*i.e.*, to be more negative or less positive), thus signaling over-statements of the regression-based baseline, than the unadjusted 10-in-10 baselines. This makes sense, as the 3-in-10 baseline is averaged over the three highest loads in the 10-in-10 baseline, and thus should always be at least as large as that baseline. Second, for the commercial customers, at least 60 percent of the 3-in-10 values and 80 percent of the 10-in-10 values are positive, indicating *under-statements* relative to the regression-based baseline. Third, for both the industrial and commercial customer

accounts, the *adjusted* 10-in-10 baseline generally reduces the percent differences (compared to the 10-in-10) and shifts the distribution of percent differences toward the origin (*i.e.*, zero difference).

Figure 5.3: Percentiles of Relative Errors of Alternative Baselines – *PG&E DBP*



5.4.2 SCE DBP

Table 5.4 summarizes the *accuracy* results for the alternative baselines compared to the regression-based baseline for SCE's DBP bidders, for each of the industry groups. Figure 5.4 presents the same results in graphical form. The results indicate that in the case of the SCE DBP events in 2009, the program baselines differed most overall from the regression-based baseline for the large number of industrial-type customer accounts, where average differences ranged from over 30 percent for the unadjusted 3-in-10 baseline to 25 percent for the *adjusted* 10-in-10 baseline. Differences between baselines were smallest for the commercial-type customer accounts, ranging from 7.4 percent for the unadjusted 3-in-10 to 4.4 percent for the adjusted 10-in-10 baseline.

Table 5.4: Accuracy of Alternative Baselines – SCE DBP
(*Relative Root Mean Square Error*)

Customer Type	Customer Event-hours	Unadjusted		Adjusted
		3-in-10	10-in-10	10-in-10
Industrial	30,808	31.3%	26.8%	24.9%
Commercial	16,568	7.4%	6.8%	4.4%
Schools	4,480	16.4%	26.5%	18.8%
TOTAL	51,856	26.6%	22.8%	21.0%

Figure 5.4: Accuracy of Alternative Baselines – SCE DBP
(*Relative Root Mean Square Error*)

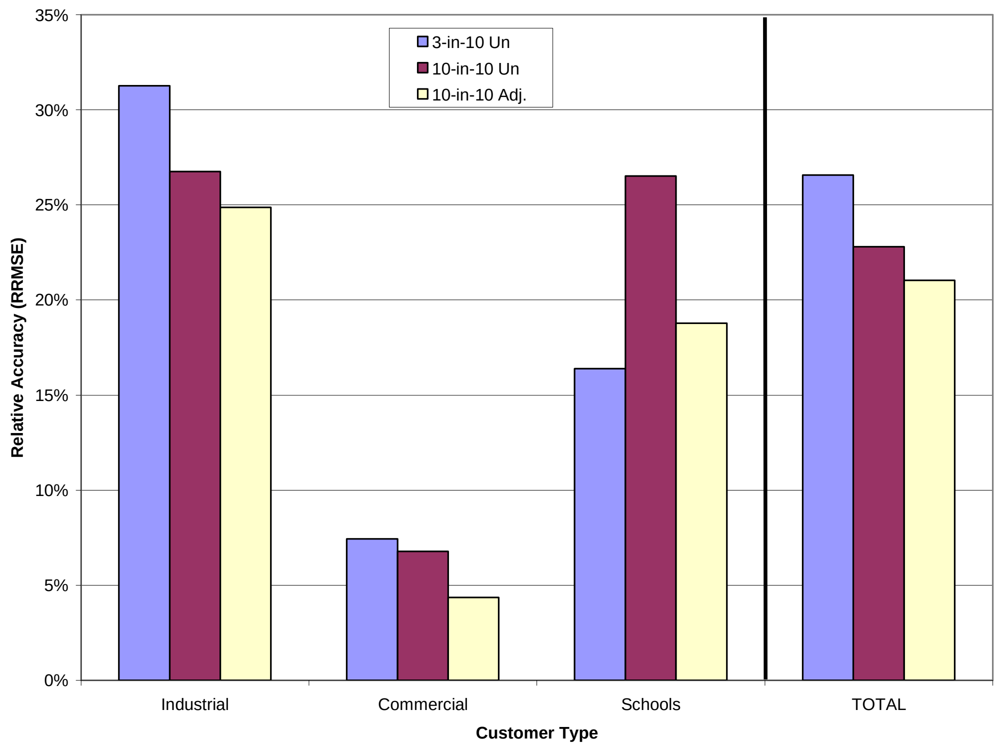


Table 5.5 presents results for the typical *bias* of the alternative baselines relative to the regression-based baseline. The unadjusted 3-in-10 results suggest that the current program baseline typically *over-states* load impacts for both the industrial and commercial categories (negative values), while *under-stating* load impacts for school customers (relative to the regression-based estimate). The results for the adjusted 10-in-10 baselines indicate a reduction in the typical biases for industrial and commercial accounts, but not for schools, whose typical 6 percent under-statement grows to nearly 12 percent. Additional insight into the range of baseline differences across customer accounts is provided in the tables and figures below.

Table 5.5: Bias of Alternative Baselines – SCE DBP (*Median Percent Difference*)

Customer Type	Customer Event-hours	Unadjusted 3-in-10	Unadjusted 10-in-10	Adjusted 10-in-10
Industrial	30,808	-5.2%	2.8%	-0.2%
Commercial	16,568	-1.1%	4.5%	-0.3%
Schools	4,480	5.8%	19.3%	11.7%
TOTAL	51,856	-3.0%	4.1%	0.2%

Figure 5.5: Bias of Alternative Baselines – SCE DBP (*Median Percent Difference*)

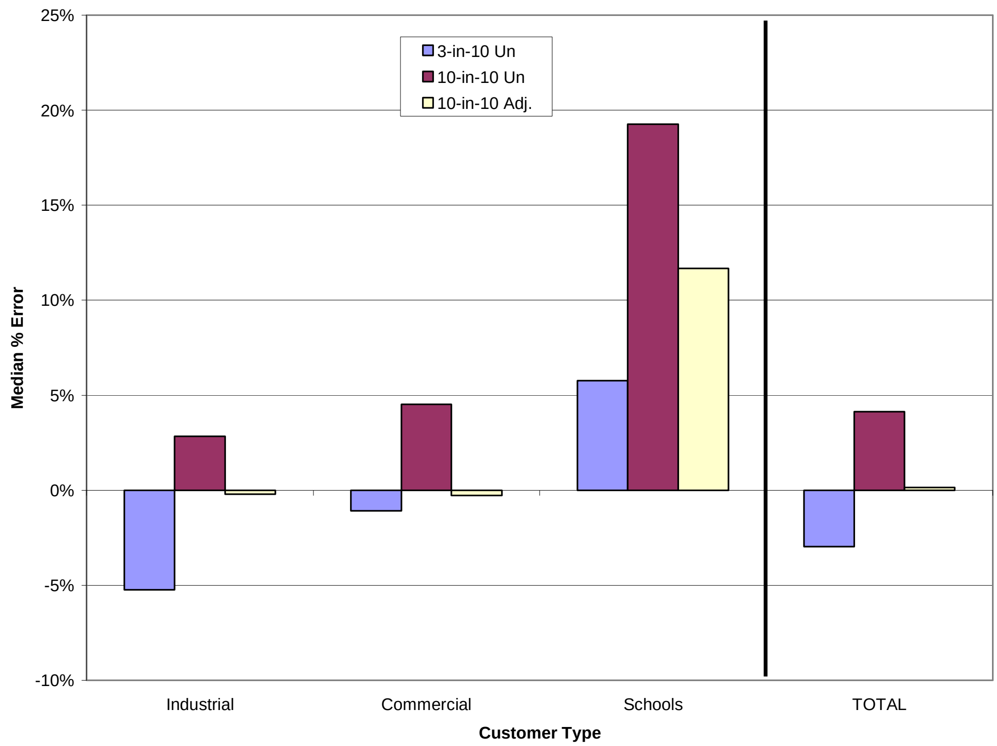


Table 5.6 expands on the single median value of the percent differences between the three alternative baselines and the regression-based values by providing values that determine *deciles* of the percent differences. Nine values are provided, each representing boundary values that separate 10 percent of the customer-hour values ordered by size. The 50 percentile values represent the median values of the distributions of differences. Thus, for example, the median percent difference for the unadjusted 3-in-10 baseline for the industrial-type customers is negative 5.2 percent, indicating a modest "typical" over-statement relative to the regression-based baseline. However, the 30th percentile value indicates that 30 percent of the over-statements exceed 16 percent, while the 70th percentile value indicates that another thirty percent of the values reflect *under-statements* that exceed 0.5 percent. The distributions for the commercial-type customer accounts are generally "tighter."

Table 5.6: Percentiles of Percent Errors of Alternative Baselines – *SCE DBP*

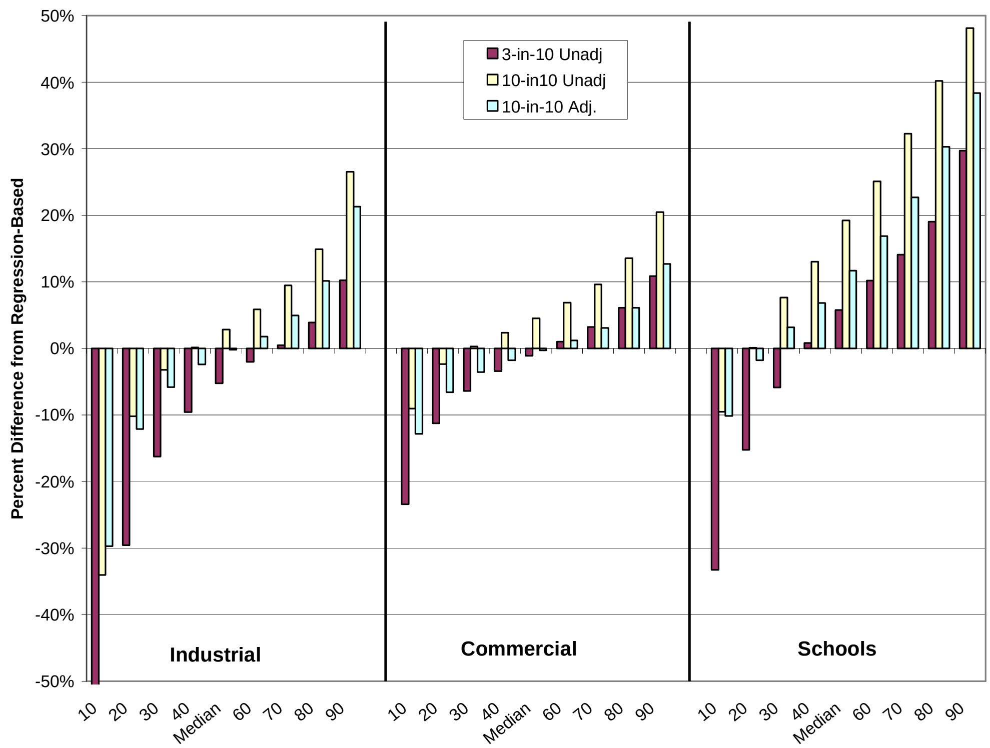
Customer Type	Percentile	Customer Event-hours	Unadjusted 3-in-10	Unadjusted 10-in-10	Adjusted 10-in-10
Industrial		30,808			
	10		-70.0%	-34.1%	-29.7%
	20		-29.6%	-10.2%	-12.1%
	30		-16.3%	-3.2%	-5.8%
	40		-9.6%	0.1%	-2.4%
	Median		-5.2%	2.8%	-0.2%
	60		-2.0%	5.9%	1.8%
	70		0.5%	9.5%	5.0%
	80		3.9%	14.9%	10.2%
	90		10.3%	26.5%	21.3%
Commercial		16,568			
	10		-23.4%	-9.0%	-12.8%
	20		-11.3%	-2.3%	-6.6%
	30		-6.4%	0.3%	-3.6%
	40		-3.4%	2.4%	-1.8%
	Median		-1.1%	4.5%	-0.3%
	60		1.0%	6.9%	1.2%
	70		3.2%	9.7%	3.0%
	80		6.1%	13.6%	6.1%
	90		10.9%	20.5%	12.7%
Schools		4,480			
	10		-33.3%	-9.5%	-10.1%
	20		-15.2%	0.1%	-1.8%
	30		-5.9%	7.7%	3.2%
	40		0.8%	13.1%	6.9%
	Median		5.8%	19.3%	11.7%
	60		10.2%	25.1%	16.9%
	70		14.1%	32.3%	22.7%
	80		19.1%	40.2%	30.3%
	90		29.7%	48.2%	38.4%

Figure 5.6 illustrates the decile values graphically for the three customer types. The same three features of the distributions of percent differences for the alternative baselines stand out as in the PG&E results. First, for all three industry types the decile values for the 3-in-10 baselines tend more toward the negative direction (*i.e.*, to be more negative or less positive) than the 10-in-10 baselines. Again, this makes sense, as the 3-in-10 baseline is averaged over the three highest loads in the 10-in-10 baseline, and thus should always be at least as large as that baseline. Second, for the *commercial* customers, between 40 and 50 percent of the 3-in-10 values and more than 70 percent of the 10-in-10 values are positive, indicating under-statements relative to the regression-based baseline. Third, for both the industrial and commercial customer accounts, the *adjusted* 10-in-10 baseline generally reduces the percent differences (compared to the unadjusted 10-in-10) and shifts the distribution of percent differences toward the origin (*i.e.*, zero difference). In

addition, the large values at the negative end of the distribution for industrial customers suggest fairly large baseline errors for a number of DBP bidders of that type.

Finally, the distributions of percent differences for *schools* suggest that all of the alternative baselines tend to under-state the baselines as measured by the regression equations for at least 70 to 80 percent of the customer-hour observations (*i.e.,* all but the 10th, 20th, or 30th decile values are positive). These results again serve to indicate the frequent difficulty of determining appropriate baseline loads for schools during the summer months.

Figure 5.6: Percentiles of Percent Errors of Alternative Baselines – *SCE DBP*



5.5 Summary of Results

The comparison of alternative baseline methods for the DBP customer accounts pointed to several consistent findings. First, all of the baseline methods applied to *commercial*-type customer accounts tended to be more accurate and less biased relative to the regression-based baseline than they did for industrial-type or school accounts. Second, the unadjusted 3-in10 program baseline tended to over-state the regression-based baseline by more than the unadjusted 10-in-10 baseline (which is not surprising since the 3-in-10 uses the 3 days with highest loads from among the 10 available). Third, the *adjusted* 10-in-10 baseline tended to reduce both over-statements and under-statements of the unadjusted baseline, and would thus be likely to improve accuracy and bias in calculating load impacts for DBP, compared to unadjusted versions of either the 3-in-10 or 10-in-10 baseline.

6. Ex Ante Load Impacts

This section documents the preparation of ex ante forecasts for 2010 to 2020 of reference loads and load impacts for PG&E's and SCE's Demand Bidding Programs. The forecasts of load impacts were developed in two primary stages. First, estimates of reference loads and percentage load impacts, on a per-enrolled customer basis, were developed based on the ex post load impact evaluations of historical data on events in 2009.[16] Second, the simulated reference loads and load impacts were combined with program enrollment forecasts from the utilities to develop forecasts of load impacts. For PG&E, separate enrollment forecasts were developed by *customer size*, *industry type* (according to NAICS code groupings), and CAISO *Local Capacity Area*. These enrollment forecasts were provided through a separate contract with The Brattle Group. For SCE, the utility forecast enrollments to continue at 2009 levels throughout the forecast time period.

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.

6.1 Ex Ante Load Impact Requirements

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

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

under both:

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

at both:

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

6.2 Description of Methods

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

6.2.1 Development of Customer Groups

For PG&E's program, customer accounts were assigned to one of three size groups, eight industry types (defined in Section 2.2), and the relevant LCA. The three size groups were the following:

[16] For PG&E, we use percentage load impacts from the 2008 program year.

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

The specific definition of "maximum demand" was based on the tariff on which the 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.

The total number of customer "cells" developed is therefore equal to 192 (= 3 size groups x 8 industry groups x 8 LCAs). While the Protocols do not require results to be reported at this level of detail, it is useful to develop per-customer load impacts and enrollments at this level of detail so that the forecast can properly account for the effects of a change in the mix of enrolled customers over time.

For SCE, the analysis was simplified because the enrollment assumes a continuation of the status quo. Therefore, we only simulated sets of reference loads for each of the three local capacity areas.

6.2.2 Development of Reference Loads and Load Impacts

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

1. Define data sources
2. Estimate ex ante regressions and simulate reference loads by 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.

Define data sources

Developing ex ante forecasts for the PG&E's Demand Bidding Program was complicated the fact that PG&E only called one test event in 2009. Furthermore, the test event overlapped with a Base Interruptible Program (BIP) event. As described in Section 4.1, customers enrolled in both DBP and BIP tended to submit bids for the second half of the DBP event and provided large load impacts for those hours. Because we do not believe that these large DBP load impacts are representative of a typical event day, we calculated percentage load impacts using estimates from the 2008 program year. While only one test event was also called in that program year, the event did not overlap with a BIP event and appears to contain load impacts that are more representative of a typical DBP event day.

In addition, PG&E's current Demand Bidding Program does not have customers in some of the cells required by the ex ante analysis. For the 20 to 200 kW cells, we use the Offices, etc. load profile as a proxy shape. For the under 20 kW cells, we use the corresponding industry group's shape from the non-residential TOU study.

Simulate reference loads

In order to develop reference loads, we first re-estimated regression equations for each enrolled 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 3.2, differing in two ways. First, for SCE the event variables were modified from the version that produces 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. (PG&E only had one test event, so this modification was not required.) 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 particular events, 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.

Once the models were re-estimated, we simulated 24-hour load profiles for each required scenario. Each of the profiles was simulated as an average of Tuesday, Wednesday, and Thursday profiles. The typical event day was assumed to occur in August. Much of the differences across scenarios can be attributed to varying weather conditions. The definitions of the 1-in-2 and 1-in-10 weather years were modified from the definitions used in the 2009 report. The utilities moved away from using weather for a particular year to a process for identifying weather extremes on a monthly basis.

Because of small sample sizes in some cells for PG&E's program, 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 ex ante reference load profiles across PG&E's LCAs were thus solely due to differences in the weather conditions used in the simulations.

Calculate forecast percentage load impacts

For PG&E, forecast percentage load impacts were differentiated by industry group. Because the test-event hours (2:00 p.m. to 6:00 p.m.) did not correspond to the simulated event hours (Noon to 8:00 p.m.), we calculated percentage load impacts for three hour types: event hours, hours adjacent to event hours, and other hours. Because the ex post sample did not have customers in the "Other or unknown" industry group, we used the Offices, etc. industry group as a proxy.

For SCE, the process was simpler. The historical event hours matched the forecast event hours (with the exception of the test event, which was excluded from the calculations), so we simply calculated hourly percentage load impacts directly from the ex post results. Separate load impacts were calculated by LCA.

For both utilities, the scenarios uncertainty-adjusted load impacts were based on the ex post load impact variation (which is based on the standard errors of the estimated load impacts).

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

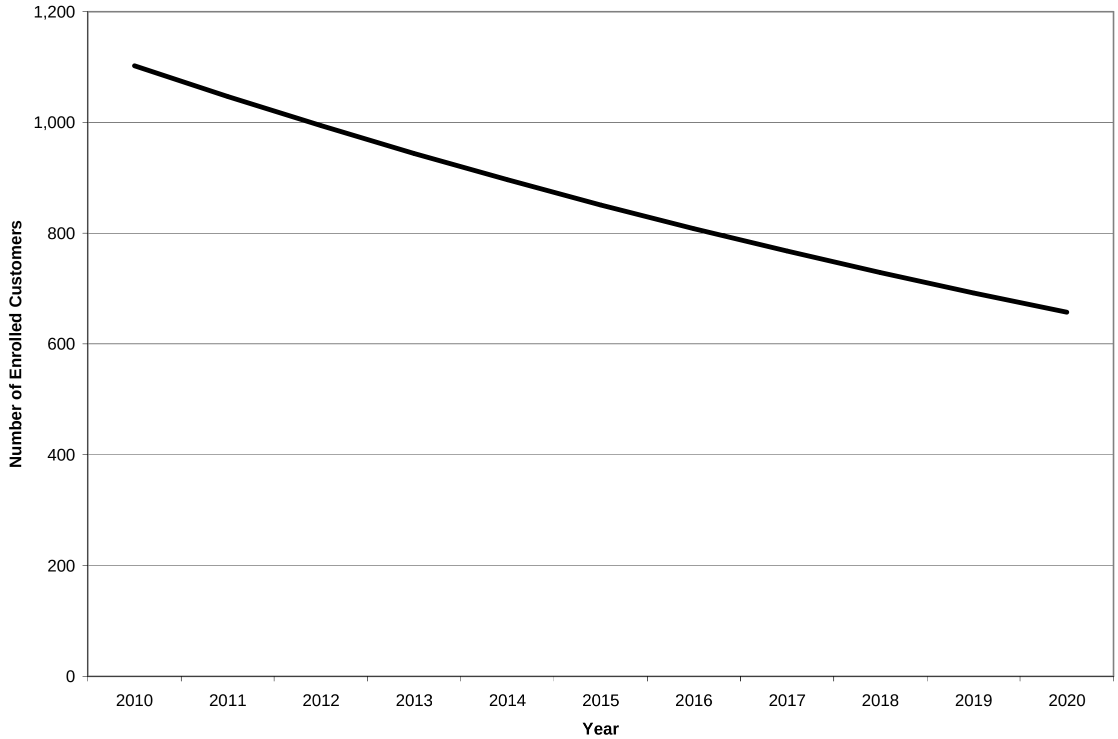
Apply forecast enrollments to produce program-level load impacts. For PG&E, The Brattle Group produced load impacts at the program level, portfolio level, and by LCA by applying the database of per-customer load impacts created in the previous step to their enrollment forecasts. The per-customer reference loads and load impacts were first scaled to match the expected *size* of customers (measured as annual average usage) 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. For SCE, we used 2009 program year enrollments by LCA for all forecast years.

6.3 Enrollment Forecasts

This section summarizes the enrollment forecasts, and resulting reference loads and ex ante load impact forecasts. Detailed tables of all results required by the Protocols are provided in associated appendices.

Figure 6.1 illustrates PG&E's DBP enrollment forecast (as developed by The Brattle Group). Enrollments steadily decline over the forecast period, from approximately 1,100 in 2010 down to 650 in 2020. SCE anticipates that enrollment in DBP will remain stable at 1,311 service accounts over the forecast horizon. By local capacity area, enrollments are 1,046 in the LA Basin LCA, 62 in the Outside LA Basin LCA, and 203 in the Ventura LCA.

Figure 6.1: Enrollment Forecasts – PG&E DBP



6.4 Reference Loads and Load Impacts

For each utility and program type, we provide the following summary information regarding the load impact forecasts, including the hourly profile of reference loads and load impacts for typical event days; the level of load impacts across years; and the distribution of load impacts by local capacity area.

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 Appendix.

6.4.1 PG&E

Figure 6.2 shows the program-level August 2012 forecast load impacts for a typical event day in a 1-in-2 weather year. Event-hour load impacts range from 23.6 MW to 24.6 MW, which represent approximately 2.8 percent of the enrolled reference load. Figure 6.3 shows the same load impacts at the portfolio (*i.e.*, when all DR programs are simultaneously called). On average, the load impacts are reduced by 4.3 MW to 19.9 MW. The percentage load impact goes down slightly to 2.7 percent.

Figure 6.2: Hourly Event Day Load Impacts for the Typical Event Day in a 1-in-2 Weather Year for August 2012, Program Level

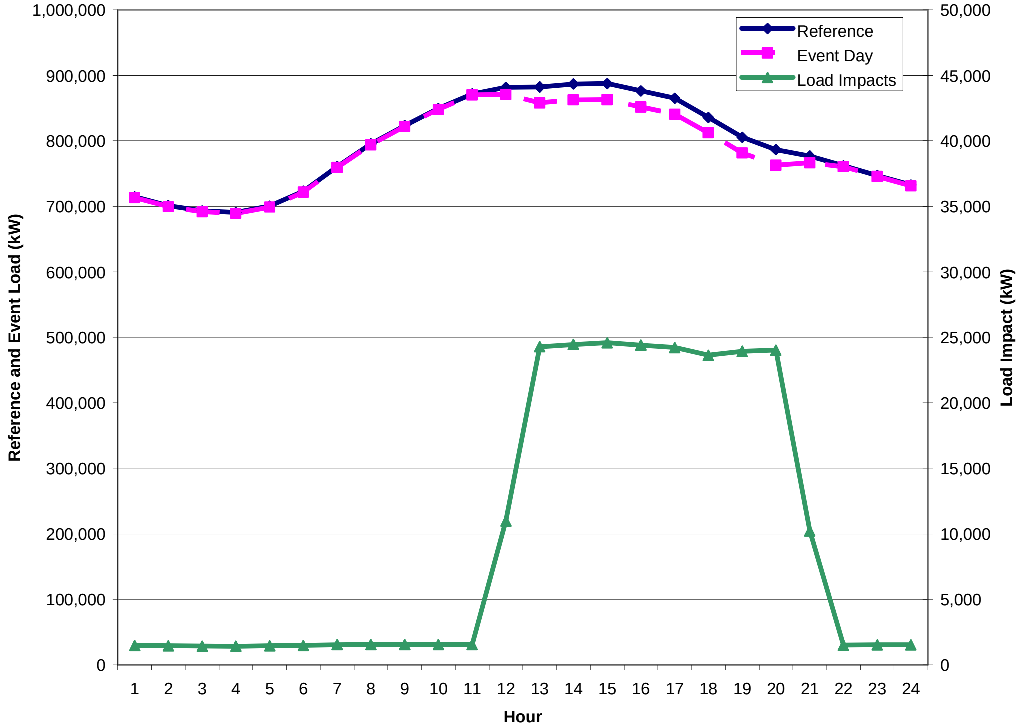


Figure 6.3: Hourly Event Day Load Impacts for the Typical Event Day in a 1-in-2 Weather Year for August 2012, Portfolio Level

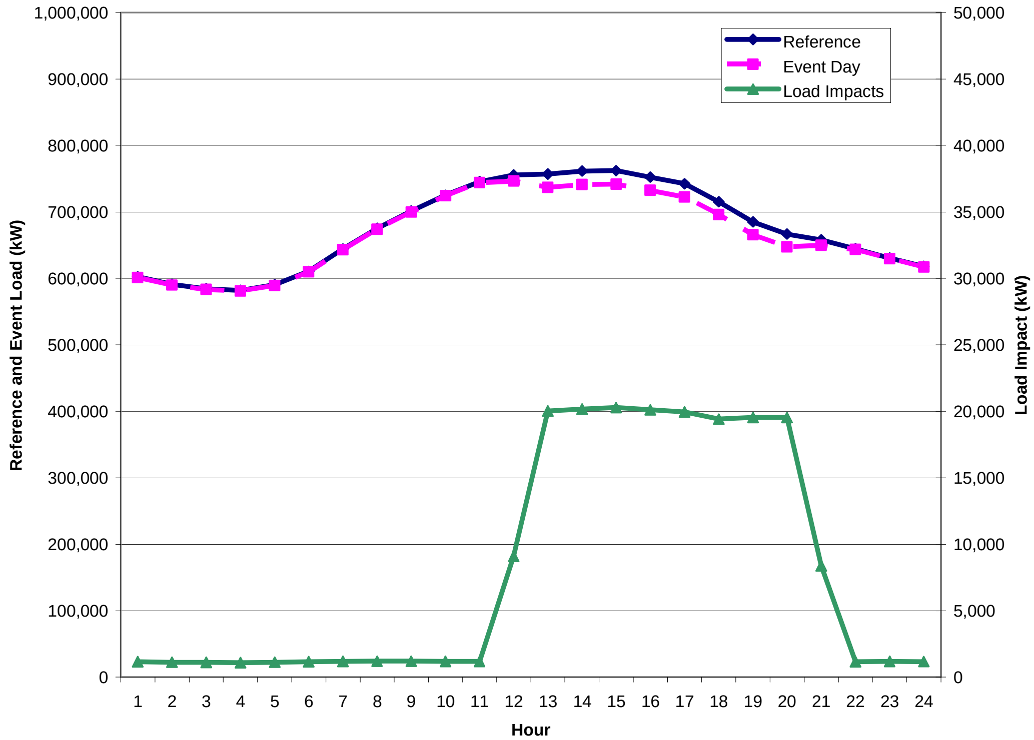


Figure 6.4 shows the share of load impacts by local capacity area, assuming a typical event day in an August 2012 1-in-2 weather year. The Greater Bay Area accounts for the largest share, with 46 percent of the load impacts.

Figure 6.4: Share of Load Impacts by LCA for the August 2012 Typical Event Day in a 1-in-2 Weather Year

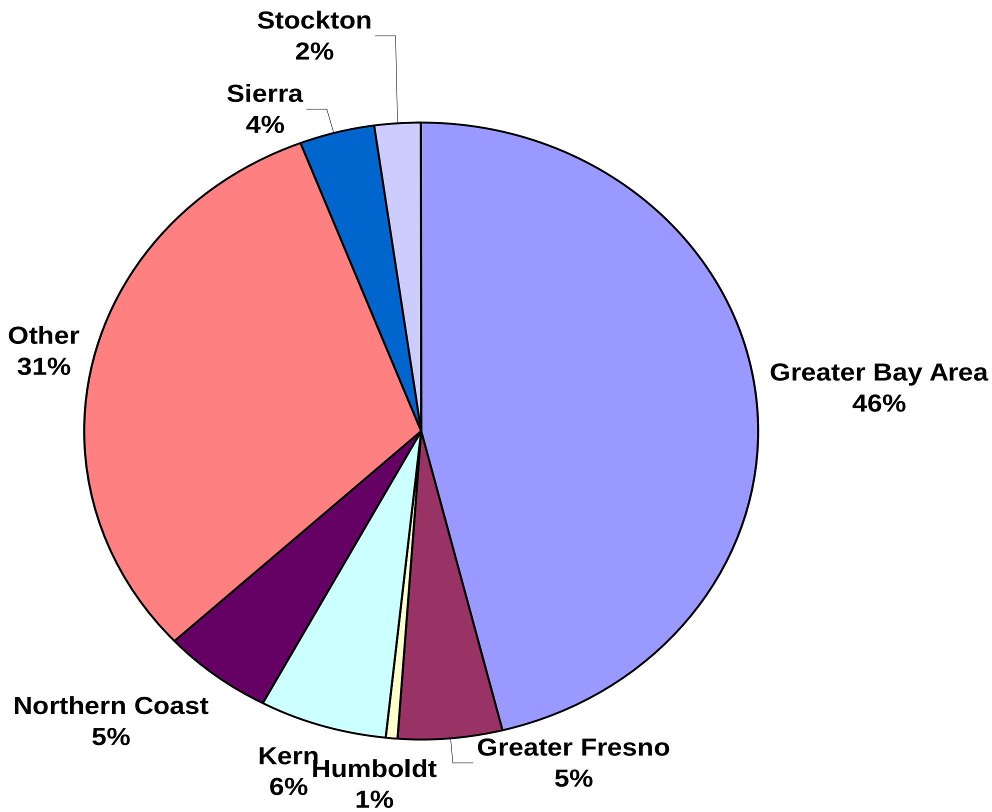
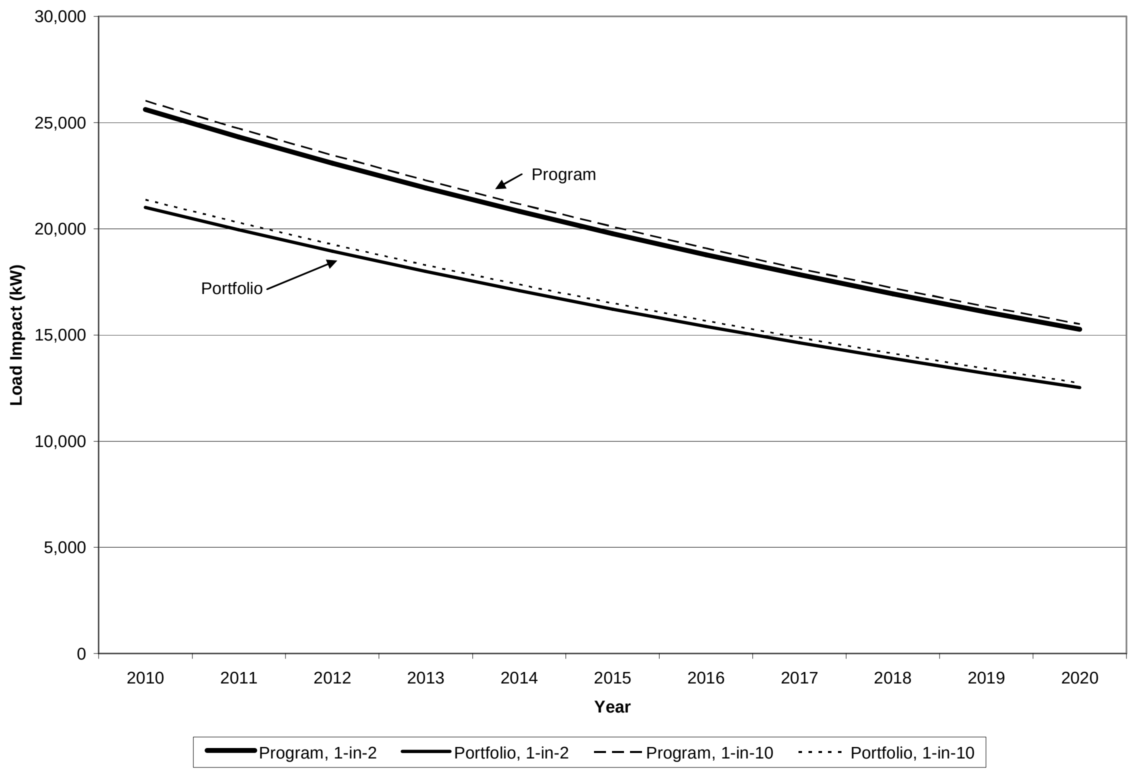


Figure 6.5 illustrates level of load impacts across the forecast time period. Four scenarios are shown, differentiated by weather year (1-in-2 and 1-in-10) and program versus portfolio-level impacts. The program-level load impacts decline from approximately 25 MW in 2010 to 15 MW in 2020. The portfolio-level load impacts decline from 21 MW in 2010 to 12.5 MW in 2020.

Figure 6.5: Average PG&E DBP Hourly Load Impacts by Year



6.4.2 SCE

Figures 6.6 and 6.7 show the forecast reference load and load impacts for a typical event day in a 1-in-2 and 1-in-10 weather year, respectively. For SCE, the load impacts are the same in each forecast year. The enrollments, percentage load impacts, and temperature profiles are all assumed to remain constant across years.

The 1-in-2 typical event day load impacts average 42.3 MW across the event hours, or 4.1 percent of the reference load. The figures show only small differences across the two weather years, with load impacts increasing to an average of 43.5 MW in the 1-in-10 weather year.

Figure 6.6: Hourly Event Day Load Impacts for the Typical Event Day in a 1-in-2 Weather Year

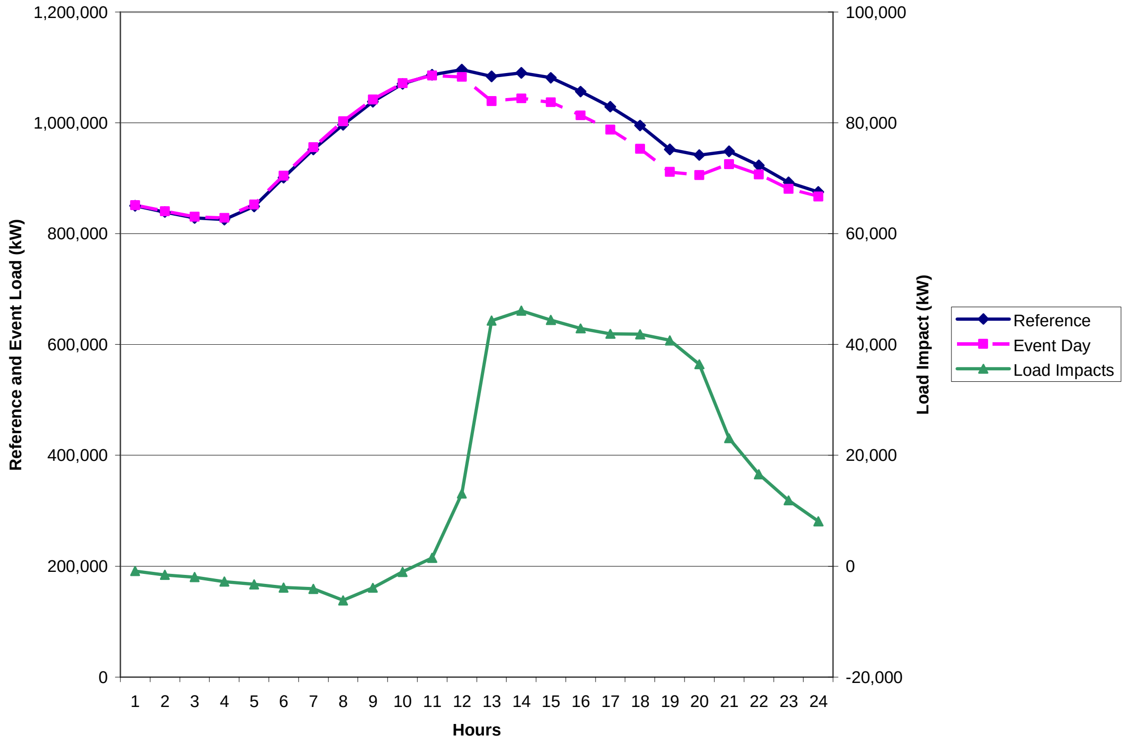


Figure 6.7: Hourly Event Day Load Impacts for the Typical Event Day in a 1-in-10 Weather Year

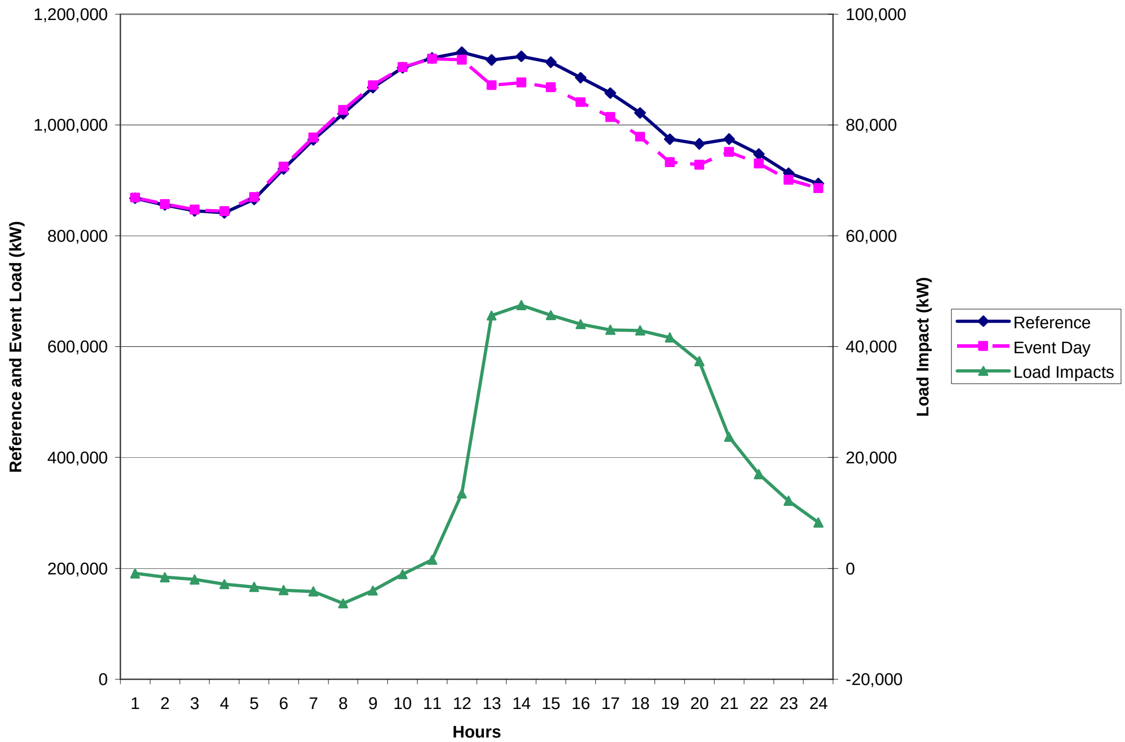


Figure 6.8: Share of SCE DBP Load Impacts by Local Capacity Area

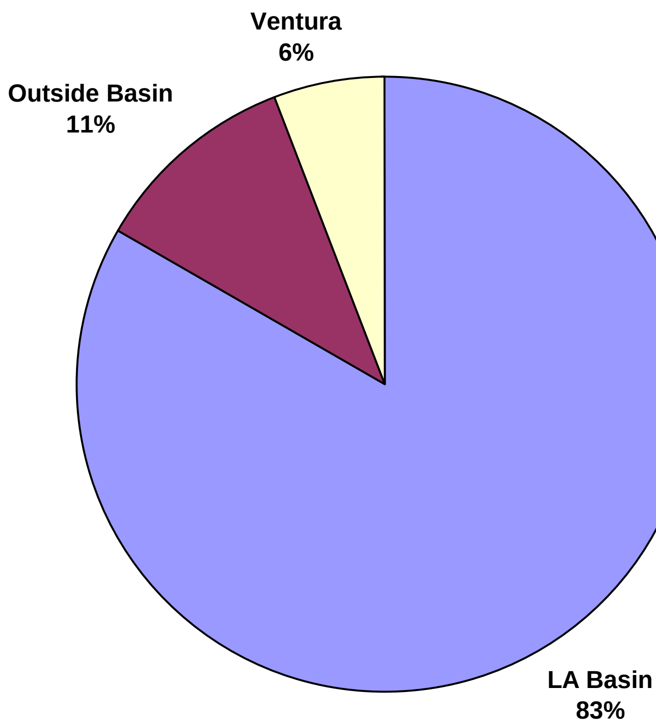
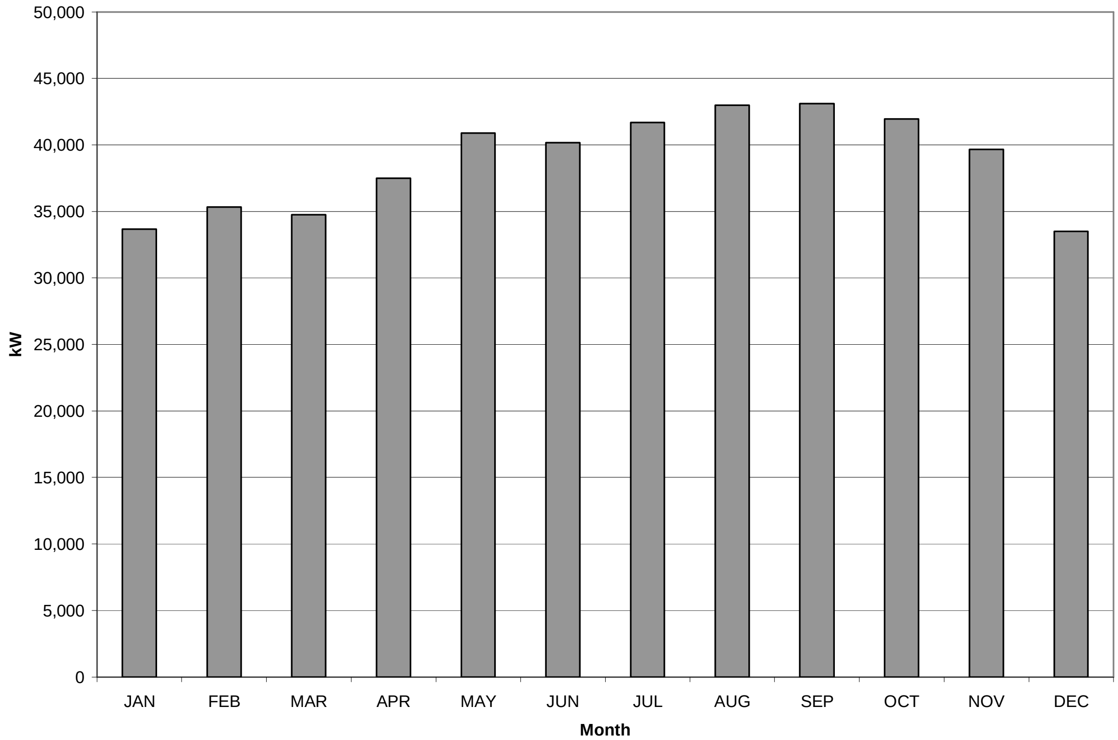


Figure 6.8 shows the distribution of load impacts across local capacity areas. The LA Basin accounts for the largest share, with 83 percent of the total load impacts.

Figure 6.9 illustrates the average hourly load impact across monthly system peak days of a 1-in-2 weather year. Because we have not observed DBP event days in non-summer months, the percentage load impacts are constant across months. The level of the load impacts varies with the size of the reference loads.

Figure 6.9: Average Event-.Hour Load Impacts by Monthly System Peak Day in a 1-in-2 Weather Year



7. 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 submitted bids, 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 and 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 DBP event days, we zero out the estimated load impact. Otherwise, we retain the estimates for the higher level summaries of load impacts.

8. Recommendations

If future program years provide more diversity in events, it would be useful to explore the relationship between BIP and DBP load impacts. For 2009, PG&E only called one DBP event that happened to overlap with a BIP event. Because we do not observe DBP event days that did not overlap with BIP events, we cannot know whether the large DBP load impacts provided by BIP participants would be provided in the absence of the BIP event.