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2013 Load Impact Evaluation of California Statewide Demand Bidding Programs (DBP) for Non-Residential Customers: Ex Post and Ex Ante Report

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Abstract

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"), Southern California Edison ("SCE"), and San Diego Gas and Electric Company ("SDG&E") in 2013. The report provides estimates of ex post load impacts that occurred during events called in 2013 and an ex ante forecast of load impacts for 2014 through 2024 that is based on utility enrollment forecasts and the ex post load impacts estimated for program years 2011 through 2013.

In addition, Decision 12-04-045 issued by the California Public Utilities Commission (CPUC) on April 19, 2012 requires a baseline analysis for DBP. Baselines are the basis for DBP payments to customers, as they represent estimates of the hourly energy that the customer would have used in the absence of a DBP event. This report contains the baseline evaluation required by the Decision.

DBP is a voluntary demand response bidding program that provides enrolled customers with the opportunity to receive financial incentives for providing load reduction on event days. Credits are based on the difference between the customers' actual metered load during an event to a baseline load that is calculated from each customer's usage data prior to the event. For the most part, customers are notified of events by 12:00 noon on the previous day. Day-of notice is provided for one of SDG&E's two DBP schedules.

PG&E called six events, with an hour-ending 13:00 to 20:00 event window. All DBP customers were called for three of the events, while the remaining three were dispatched for a sub-set of locations. SCE called five eight-hour events from hours ending 13:00 through 20:00. SDG&E called two day-of notice events and one day-ahead notice event. One day-of notice event was for hours ending 13:00 through 16:00, while the remaining events were from hours ending 14:00 through 17:00. Enrollment in PG&E's DBP averaged 952 service accounts across the three event days during which all customers were called. The sum of enrolled customers' coincident maximum demands was 856 MW. Enrollment in SCE's DBP averaged 1,312 service accounts across the 2013 event days. The sum of enrolled customers' coincident maximum demands on these days was 994 MW. Each of SDG&E's programs consisted of a single customer, with multiple service accounts associated with each of them.

Ex post load impacts were estimated from regression analysis of customer-level hourly load data, where the equations modeled hourly load as a function of variables that control for factors affecting consumers' hourly demand levels. DBP load impacts for each event were obtained by summing the estimated hourly event coefficients across the customer-level models.

The total program load impact for PG&E's three full-dispatch events averaged 36 MW, or 4.3 percent of enrolled load. Event-specific load impacts ranged from a low of 31.0 MW to a high of 43.6 MW. During the three partial-dispatch events, the program load impact averaged 1.7 MW.

For SCE, average hourly program load impacts averaged approximately 99.5 MW across five events, or 10 percent of the total reference load. The event-specific load impacts ranged from a low of 90.6 MW to a high of 111.4 MW.

SDG&E's DBP-DA customer provided an average of 5.7 MW of demand response during its only event day. SDG&E's DBP-DO customer provided an average of 4.5 MW across its two event days.

We separately summarized average event-hour load impacts for customers participating in the Technical Assistance and Technology Incentives (TA/TI) program or the Automated Demand Response (AutoDR) program. For PG&E, an average of one TA/TI service account on each event day provided 1.6 MW of load impacts and an average of 53 bidding AutoDR service accounts provided 16.1 MW. For SCE, TA/TI load impacts averaged 15.9 MW from 72 service accounts, while AutoDR load impacts averaged 27.9 MW from 119 service accounts.

The baseline analysis analyzed measures of *accuracy* (how close the program baseline is to the "true" baseline) and *bias* (whether the program baseline has a tendency to be above or below the "true" baseline). The analysis provides strong evidence that day-of adjustments to the 10-in-10 baseline improve accuracy. However, baseline performance is not as strongly affected by the amount or presence of a cap on the day-of adjustment.

In the ex ante evaluation, SCE forecasts that DBP customer enrollment to decrease in 2014 due to the removal of "non-performing" customers. During the 2014 program year, SCE's average event-hour load impact is approximately 98 MW. PG&E forecasts DBP enrollment to drop slightly to 923 service accounts in 2014 and remain at that level through the 2014 to 2024 forecast period. PG&E's program-level load impacts are forecast to be 42.5 MW during a 1-in-2 August peak day. For both PG&E and SCE, the portfolio-level load impacts are substantially less than the program-level load impacts because of the high level of load response provided by customers dually enrolled in the Base Interruptible Program (BIP) and aggregator programs (e.g., the Capacity Bidding Program). For SCE, the portfolio-level load impact is 5.1 MW in 2014. For PG&E, the portfolio-level load impact is 3.2 MW during a 1-in-2 August peak day.

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"), Southern California Edison ("SCE"), and San Diego Gas and Electric Company ("SDG&E") in 2013. The report provides estimates of ex post load impacts that occurred during events called in 2013 and an ex ante forecast of load impacts for 2014 through 2024 that is based on utility enrollment forecasts and the ex post load impacts estimated for program years 2011 through 2013.

In addition, Decision 12-04-045 issued by the California Public Utilities Commission (CPUC) on April 19, 2012 requires a baseline analysis for DBP. Baselines are the basis for DBP payments to customers, as they represent estimates of the hourly energy that the customer would have used in the absence of a DBP event. This report contains the baseline evaluation required by the Decision.

The primary research questions addressed by this evaluation are:

1. What were the DBP load impacts in 2013?
2. How were the load impacts distributed across industry groups?
3. How were the load impacts distributed across local capacity areas?
4. What were the effects of TA/TI and AutoDR on customer-level load impacts?
5. How do alternative baseline methodologies perform?
6. What are the ex ante load impacts for 2014 through 2024?

ES.1 Resources covered

Demand Bidding Program

The Demand Bidding Program (DBP) is a voluntary bidding program that offers qualified participants the opportunity to receive bill credits for reducing its energy when a DBP event is triggered. 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. In that decision, the Investor-Owned Utilities (IOUs) were directed to continue their programs. In addition, a new SDG&E DBP was authorized by resolution E-4511 on July 17, 2012 in response to the fact that SONGS Unit 3 is offline.

The IOU's programs are designed for non-residential customers, both bundled service and direct access. Customers must have internet access and communicating interval metering approved by each of the IOUs. A DBP event may occur any weekday (excluding holidays) between the hours of noon and 8:00 p.m. and triggered on a day-ahead basis. These events may occur at any time throughout the year. DBP customers may participate in another demand response (DR) program, but that DR program must be a capacity-paying program with same day notification (e.g., Base Interruptible Program).

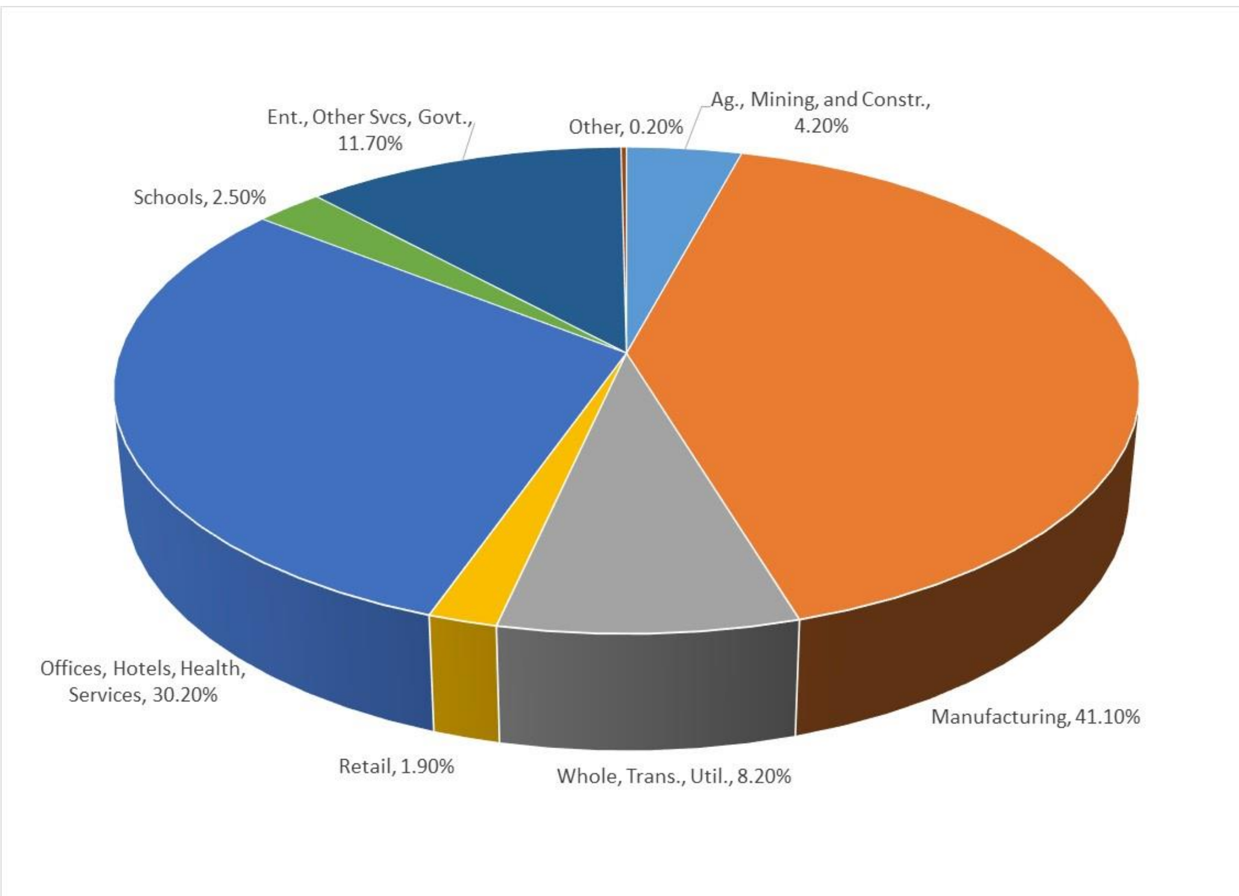
For simultaneous or overlapping events, the dual-participants receive payment for the capacity-paying program and not for the simultaneous hours of the DBP event.

PG&E called six events, each with an hour-ending 13:00 to 20:00 event window. All DBP customers were called for three of the events, while the remaining three were dispatched for a sub-set of locations. SCE called five eight-hour events from hour ending 13:00 through 20:00. SDG&E called two day-of notice events and one day-ahead notice event. One day-of notice event was for hours ending 13:00 through 16:00, while the remaining events were from hours ending 14:00 through 17:00.

Enrollment

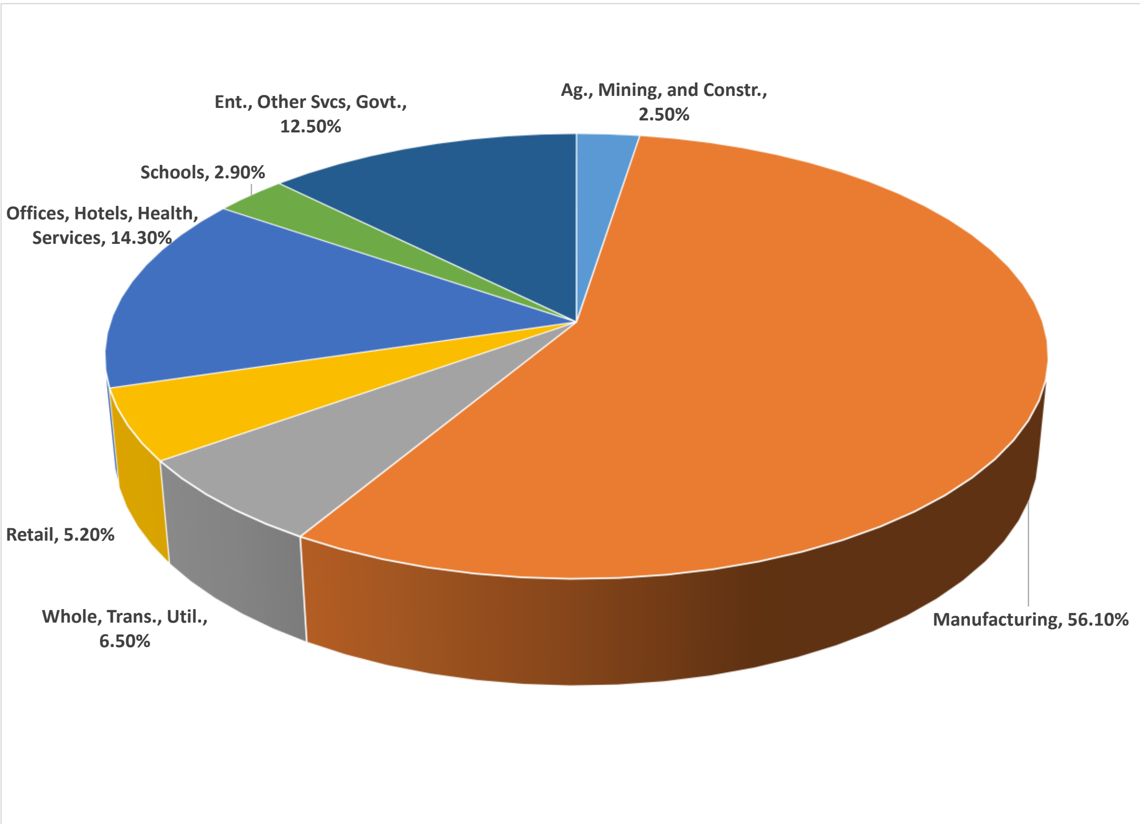
Average event-day enrollment in PG&E’s DBP decreased slightly relative to PY2012, from 998 to 952 in 2013. The sum of enrolled customers’ coincident maximum demands was 856 MW, or 0.90 MW for the average service account. The manufacturing and offices, hotels, health care and services industry groups made up the majority of PG&E’s DBP enrollment. Figure ES.1 illustrates the distribution of DBP load across the indicated industry types.

Figure ES.1 Distribution of DBP Enrolled Load by Industry Type, *PG&E*



SCE's enrollment in DBP averaged 1,312 service accounts on the PY2013 event days, which is a slight decrease relative to the average of 1,369 enrolled service accounts during the PY2012 event days. These accounted for a total of 994 MW of maximum demand, or 0.76 MW per service account. Manufacturers continued to make up more than half of the enrolled load. Figure ES.2 illustrates the distribution of SCE's DBP load across the indicated industry types.

Figure ES.2 Distribution of DBP Enrolled Load by Industry Type, *SCE*



Bidding Behavior

As in previous years, for most events, a relatively small percentage of the customer accounts enrolled in DBP actually submitted bids. For PG&E, 111 service accounts submitted a bid for at least one event. At SCE, 385 individual and lead service accounts submitted at least one bid during 2013.

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 from the customer-level regressions. 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 three events during which all customers were called averaged 36 MW, or 4.3 percent of enrolled load. This is quite close to the 38 MW average load impact from the previous program year. All but 1.2 MW of the load impacts came from customers dually enrolled in DBP and either BIP or an aggregator program (AMP or CBP). Event-specific load impacts ranged from a low of 31.0 MW to a high of 43.6 MW. During the three partial-dispatch events, the program load impact averaged 1.7 MW.

For SCE, average hourly program load impacts averaged approximately 99.5 MW across five events, or 10 percent of the total reference load. All but 5.8 MW of the load impacts came from customers dually enrolled in DBP and either BIP or an aggregator program (e.g., Capacity Bidding Program). The event-specific load impacts ranged from a low of 90.6 MW to a high of 111.4 MW.

SDG&E's DBP-DA customer provided an average of 5.7 MW of demand response during its only event day. SDG&E's DBP-DO customer provided an average of 4.5 MW across its two event days.

ES.4 TA/TI and AutoDR Effects

We separately summarized average event-hour load impacts for customers participating in the Technical Assistance and Technology Incentives (TA/TI) program or the Automated Demand Response (AutoDR) program. For PG&E, one TA/TI service account participated in each DBP event and provided an average of 1.6 MW of load impacts. For AutoDR, the number of participating service accounts ranged from 51 to 55 over the three events during which all customers were called and provided an average of 16.1 MW of load impacts. For SCE, TA/TI load impacts averaged 15.9 MW from 72 service accounts, while AutoDR load impacts averaged 27.9 MW from 119 service accounts.

ES.5 Baseline Analysis

For PG&E and SCE, DBP uses a 10-in-10 baseline method, including an optional day-of adjustment based on the ratio of the current day's pre-event usage level to the usage level in the same period for the 10-in-10 baseline.[1] The tariff language currently limits this adjustment to +/- 20 percent. As required by Decision 12-04-045, this report studies the following alternative baseline methodologies: unadjusted baselines, and day-of adjusted baselines with cap percentages of 20, 30, 40, and 50 percent, as well as an uncapped adjustment.

Two sets of days are examined: PY2013 event days; and a set of event-like non-event days. For the event days, the baselines are compared 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. Measures of *accuracy* (how close the program baseline is to the "true" baseline) and *bias* (whether the program baseline has a tendency to be above or below the "true" baseline) were used in the evaluation.

The analysis provides strong evidence that day-of adjustments to the 10-in-10 baseline improve accuracy. However, baseline performance is not as strongly affected by the amount or presence of a cap on the day-of adjustment.

A similar analysis of SDG&E's DBP baseline methods was conducted. In this case, the programs use a 1-in-1 baseline method with a 40 percent cap on the day-of baseline adjustment. We evaluated the various adjustment caps for both 1-in-1 and 10-in-10 baselines. It is difficult to generalize from results based on so few customers, but it appears that the DBP-DO baselines may perform better if a 10-in-10 baseline is used, while the DBP-DA (Navy) baselines contain less evidence that a change in baseline methods would be beneficial.

ES.6 Ex Ante Load Impacts

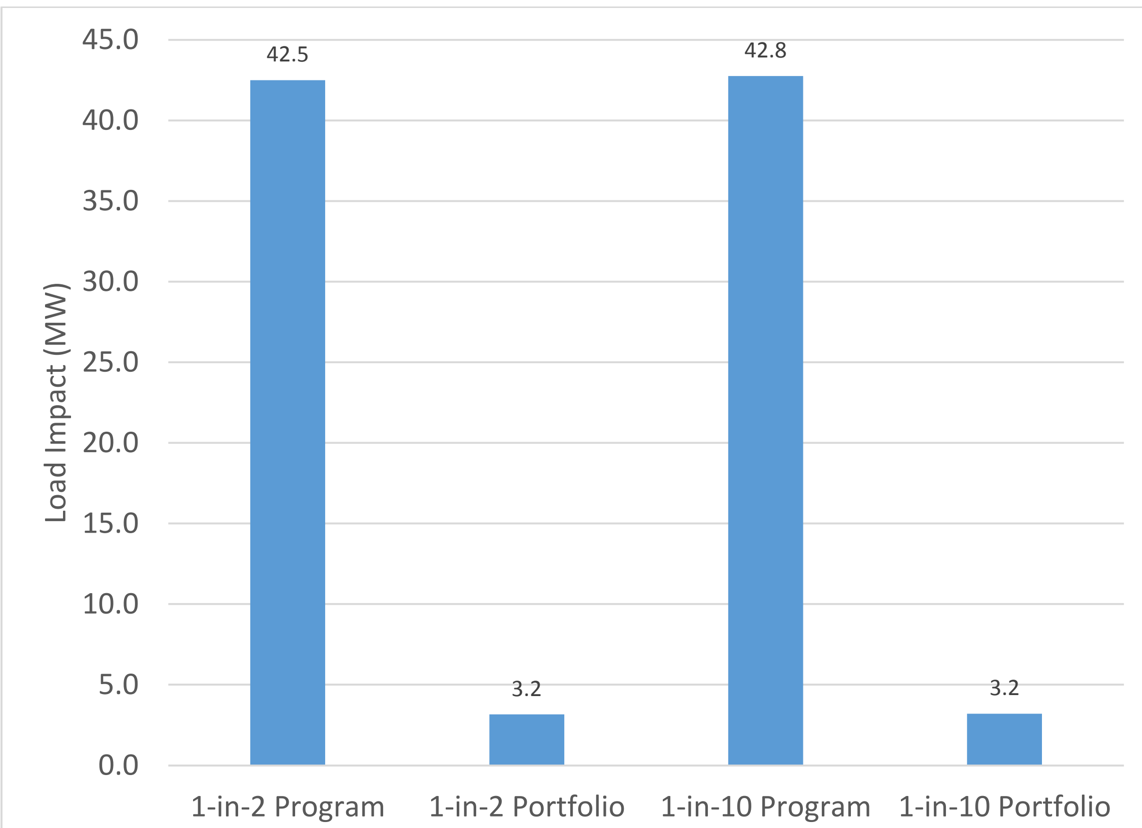
Scenarios of ex ante load impacts are developed by combining enrollment forecasts with per-customer reference loads and load impacts, which were developed using the data and results of the ex post load impact evaluation.

[1] The 10-in-10 baseline is calculated as the average energy usage for each hour across the ten most recent non-event weekdays. The day-of adjustment is calculated using average hourly consumption in the first three hours of the four hours prior to the event period.

PG&E forecasts DBP enrollment to drop slightly to 923 service accounts and remain at that level through the 2014 to 2024 forecast period.[2] SDG&E forecast enrollment consists of the currently enrolled customers in all forecast years. SCE forecasts DBP customer enrollment to decrease in 2014 due to the removal of approximately 700 "non-performing" service accounts. By the end of 2014, SCE forecasts that DBP enrollment will be 710 service accounts, where enrollment is forecast to remain through the end of the forecast period.

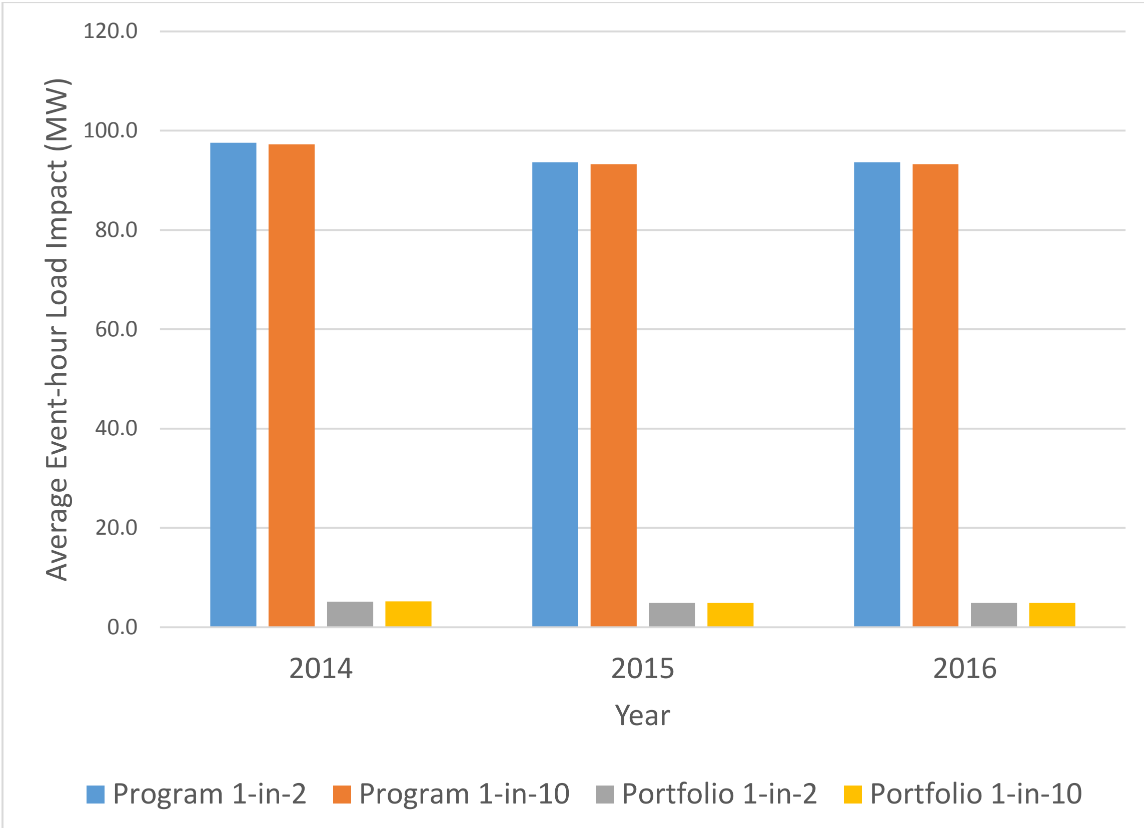
Figures ES.3 and ES.4 show the ex ante load impacts for PG&E and SCE, respectively. Both figures illustrate the large difference between program-level load impacts (which include all customers enrolled in DBP) and portfolio-level load impacts (which exclude customers dually enrolled in the Base Interruptible Program, or BIP and aggregator programs, including the Capacity Bidding Program). This is because the dually enrolled customers tend to be larger and more demand responsive than other DBP customers.

Figure ES.3: Average August Ex Ante Load Impacts by Scenario, *PG&E*



[2] PG&E filed on March 3rd its response to the bridge filing requesting removal of non-participatory customers starting in 2015. Therefore, there may be a significant decrease in enrollment relative to the forecast used in this evaluation.

Figure ES.4: Average August Ex Ante Load Impacts by Year and Scenario, *SCE*



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"), Southern California Edison ("SCE"), and San Diego Gas and Electric Company ("SDG&E") in 2013. The report provides estimates of ex post load impacts that occurred during events called in 2013 and an ex ante forecast of load impacts for 2014 through 2024 that is based on the IOU's enrollment forecasts and the ex post load impacts estimated for program years 2011 through 2013.

In addition, Decision 12-04-045 issued by the California Public Utilities Commission (CPUC) on April 19, 2012 requires a baseline analysis for DBP. Baselines are the basis for DBP payments to customers, as they represent estimates of the hourly energy that the customer would have used in the absence of a DBP event. This report contains the baseline evaluation required by the Decision.

The primary research questions addressed by this evaluation are:

1. What were the DBP load impacts in 2013?
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 do alternative baseline methodologies perform?
6. What are the ex ante load impacts for 2014 through 2024?

The report is organized as follows. Section 2 contains a description of the 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 TA/TI and AutoDR customer load impacts; Section 5 contains a study of the program baseline methodologies; Section 6 describes the ex ante load impact forecast; Section 7 contains descriptions of differences in various scenarios of ex post and ex ante load impacts; and Section 8 provides recommendations. Appendix A contains an assessment of the validity of the study.

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 2013.

2.1 Program Descriptions

DBP is a voluntary bidding program that offers qualified participants the opportunity to receive bill credits for reducing its energy when a DBP event is triggered. 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. In that decision, the IOUs were directed to continue the Demand Bidding Programs. In addition, a new SDG&E DBP was authorized by resolution E-4511 on July 17, 2012 in response to the fact that SONGS Unit 3 is offline.

DBP is designed for non-residential customers, both bundled service and direct access. Customers must have internet access and communicating interval metering approved by each of the IOUs. A DBP event may occur any weekday (excluding holidays) between the hours of noon and 8:00 p.m. and are triggered on a day-ahead basis. These events may occur at any time throughout the year. DBP customers may participate in another demand response (DR) program, but that DR program must be a capacity-paying program with same day notification (e.g., Base Interruptible Program or Capacity Bidding program). For simultaneous or overlapping events, the dual-participants receive payment for the capacity-paying program and not for the simultaneous hours of the DBP event.

PG&E's Demand Bidding Program

At PG&E, DBP is available to time-of-use customers with billed maximum demands of 50 kW or higher who commit to reduce load by a minimum of 10 kW in each hour for two consecutive hours 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 200 kW 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 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 is provided on a day-ahead basis. Events are triggered with a California ISO Alert Notice for the following day when the California ISO's day-ahead peak demand forecast is 43,000 MW or greater, or when PG&E, in its own opinion, forecasts that its other resources may not be sufficient or otherwise too costly to procure. PG&E may also activate up to two DBP test events with a simulated emergency event trigger. When an event is called, enrolled customers may choose to bid a load reduction amount for the event or not participate.

The incentive payment is $0.50 per kWh reduced below a baseline level. 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 average usage from the previous ten qualifying days (non-holiday, non-event weekdays), with the customer having the option to include a day-of adjustment based on their usage in pre-event hours. There is no charge 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 10 kW for each hour and customers may submit only one bid for each event notification.

Although PG&E customers enrolled in DBP may participate in other DR programs (Day-of notice in AMP, CBP, BIP, and OBMC), they do not receive a day-ahead DBP incentive payment for those hours in which a day-of event from another DR program in which the customer is enrolled occur simultaneously.

SCE's Demand Bidding Program

SCE's DBP design is similar to PG&E's, with two exceptions: enrolled customers are required to commit to a minimum load reduction of 1 kW (versus 10 kW at PG&E); and bidding customers are paid for load reductions up to twice their bid amount. DBP participants may also participate in AP-I, BIP, SDP, or AMP (formerly DRC). However, the customer will not receive DBP incentive payments during overlapping event hours.

SDG&E's Demand Bidding Program

SDG&E has two DBP programs, as described below:
Schedule DBP-DA (Navy): Schedule DBP-DA (Navy) is restricted to Navy customers and provides day-ahead notice of event days. This program is applicable to customers who are capable of providing at least a 3 MW load reduction based on the customer's specific baseline. The DBP-DA incentive is $0.40 per kWh for customers who purchase commodity from the utility (bundled customers).

Schedule DBP-DO: Demand/energy bidding program that offers incentives to non-residential customers for reducing energy consumption and demand during a specific Demand Bidding Event. This program is applicable to customers who are capable of providing at least a 5 MW load reduction based on the customer's specific baseline. The DBP-DA Incentive is $0.50 per kWh for customers who purchase commodity from the utility (bundled customers).

Schedule DBP-DO and DBP-DA programs are available year-round and there is no limit to the number of Demand Bidding Events per month or per year. A customer may not participate simultaneously in DBP-DA or DBP-DO and any other Demand Response rate or program.

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 North American Industry Classification System (NAICS) codes:

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).[3] Note that while we report load impacts by LCA as required by the Protocols, PG&E's DBP was recently modified to allow for locational dispatch, where the locations are determined by sub-LAP.[4]

2.2.2 Program Participants by Type

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 on the average event day. Enrollment in PG&E's DBP decreased slightly relative to PY2012, from 998 to 952 in 2013.[5] The sum of enrolled customers' coincident maximum demands[6] was 856 MW, or 0.90 MW for the average service account. The manufacturing and offices, hotels, health care and services industry groups made up the majority of PG&E's DBP enrollment.

[3] 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.

[4] In Ordering Paragraph 10 of Decision 12-06-025, dated June 21, 2012, the California Public Utility Commission (CPUC or Commission) stated the following: Pacific Gas and Electric Company's Aggregator Managed Program, Capacity Bidding Program and Demand Bidding Program shall be counted for Resource Adequacy in the 2013 Resource Adequacy compliance year. These programs must be locally dispatchable by May 1, 2013.

[5] "Enrollment" is defined as the average enrollment on event days during the 2013 program year. This differs from the pre-PY2012 load impact evaluation, in which we summarized the number of customers enrolled at any time during the program year. The change facilitates the summary of coincident demands (where the previous report summarized non-coincident demands) and improves consistency between the customer characteristics tables and the load impact summary tables.

[6] Customer-level demand ("Sum of Max MW" in the tables) is calculated as the coincident maximum demand averaged across event days, including the estimated load impacts (i.e., using the reference loads).

Table 2.1: DBP Enrollees by Industry Group, *PG&E*

Industry Type	# of Service Accounts	Sum of Max MW[7]	% of Max MW	Ave. Max MW[8]
1.Agriculture, Mining, Construction	104	36	4.2%	0.34
2.Manufacturing	198	352	41.1%	1.78
3.Wholesale, Transportation, Utilities	135	70	8.2%	0.52
4.Retail	96	16	1.9%	0.17
5.Offices, Hotels, Health, Services	264	259	30.2%	0.98
6.Schools	30	22	2.5%	0.72
7. Entertainment, Other Services, Government.	116	100	11.7%	0.87
8.Other				
TOTAL	**952**	**856**		**0.90**

Table 2.2 shows comparable information on DBP enrollment for SCE. SCE's enrollment in DBP averaged 1,312 service accounts across the PY2013 event days, which is a slight decrease relative to the average of 1,369 enrolled service accounts across the PY2012 event days. These accounted for a total of 994 MW of maximum demand, or 0.76 MW per service account. Manufacturers continued to make up more than half of the enrolled load.

Table 2.2: DBP Enrollees by Industry Group, *SCE*

Industry Type	# of Service Accounts	Sum of Max MW	% of Max MW	Ave. Max MW
1.Agriculture, Mining, Construction	28	25.0	2.5%	0.89
2.Manufacturing	328	557.7	56.1%	1.70
3.Wholesale, Transportation, Utilities	146	65.1	6.5%	0.45
4.Retail	185	51.4	5.2%	0.28
5.Offices, Hotels, Health, Services	237	142.0	14.3%	0.60
6.Schools	288	28.5	2.9%	0.10
7.Entertainment, Other Services, Government.	100	124.6	12.5%	1.24
TOTAL	**1,312**	**994.4**		**0.76**

Tables 2.3 and 2.4 show DBP enrollment by local capacity area for PG&E and SCE, respectively. Note that some results have been removed due to confidentiality concerns.

[7] "Sum of Max MW" is defined as the sum of the event-day coincident peak demands across service accounts. The reported values include the estimated load impacts.
[8] "Ave. Max MW" is calculated as "Sum of Max MW" divided by the "# of Service Accounts."

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

Local Capacity Area	# of Service Accounts	Sum of Max MW	% of Max MW	Ave. Max MW
Greater Bay Area	442	397	46.3%	0.90
Greater Fresno				
Humboldt				
Kern				
Northern Coast				
Not in any LCA	273	353	41.3%	1.29
Sierra				
Stockton				
TOTAL	**952**	**856**		**0.90**

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

Local Capacity Area	# of Service Accounts	Sum of Max MW	% of Max MW	Ave. Max MW
LA Basin				
Outside LA Basin				
Ventura				
TOTAL	**1,312**	**994.4**		**0.76**

Tables 2.5 and 2.6 summarize average event-day bidding behavior by industry group. The average hourly bid is calculated first at the customer level, only over the hours in which the customer submitted a bid. The customer-level averages are then summed within industry group to arrive at the values in the tables. For both utilities, the manufacturing industry group had the highest amount of load that submitted a bid. Note that the total bid amounts shown in this table exceed the amount bid during any one event hour. A summary of bid amounts by event is included in Section 4.

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

Industry Type	# Bidders	Avg. Hourly Bid MW	% of Enrolled Max MW[9]
1.Agriculture, Mining, Construction	18	2.1	5.3%
2.Manufacturing	26	36.5	10.5%
3.Wholesale, Transportation, Utilities	21	10.4	15.1%
4.Retail			
5.Offices, Hotels, Health, Services	18	4.3	1.7%
6.Schools			
7.Entertainment, Other Services, Government.			
TOTAL	**111**	**55.5**	**6.6%**

[9] "% of Enrolled Max MW" is calculated as "Avg. Hourly Bid MW" divided by the "Sum of Max MW" from Table 2.1.

Table 2.6: DBP Bidding Behavior, *SCE*

Industry Type	# Bidders	Avg. Hourly Bid MW	% of Enrolled Max MW
1.Agriculture, Mining, Construction	15	6.1	24.5%
2.Manufacturing	159	115.9	20.8%
3.Wholesale, Transportation, Utilities	56	15.1	23.2%
4.Retail	18	3.0	5.9%
5.Offices, Hotels, Health, Services	91	7.7	5.5%
6.Schools	24	1.8	6.3%
7.Entertainment, Other Services, Government.	22	2.6	2.1%
TOTAL	**385**	**152.3**	**15.3%**

SDG&E's DBP programs each consist of service accounts associated with a single large customer. In the interest of customer confidentiality, we do not provide its LCA, industry group, or usage statistics.

2.3 Event Days

Table 2.7 lists DBP event days for the three IOUs in 2013. PG&E called six events, each of which had an hour-ending 13:00 to 20:00 event window. Three of the events were called for only a sub-set of customers in PG&E's service territory. SCE called five eight-hour events from hours ending 13:00 through 20:00. SDG&E called three events. The first event spanned hours ending 13:00 through 16:00, while the second two were from hours ending 14:00 through 17:00. The first two events applied to only Schedule DBP and the third event applied only to Schedule DBP-DA (Navy).

Table 2.7: DBP Event Days

Date	Day of Week	SCE	PG&E	SDG&E
6/3/2013	Monday	1		
6/7/2013	Friday		1 (partial)	
6/28/2013	Friday	2		
7/1/2013	Monday		2	
7/2/2013	Tuesday	3		
7/3/2013	Wednesday		3	
8/19/2013	Monday		4 (partial)	
8/28/2013	Wednesday	4		
8/30/2013	Friday			1 (DO only)
9/5/2013	Thursday			2 (DO only)
9/6/2013	Friday			3 (DA only)
9/9/2013	Monday	5	5	
9/10/2013	Tuesday		6 (partial)	

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, 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 15 event coefficient of -100 would mean that the customer reduced load by 100 kWh during hour 15 of that event day relative to its normal usage in that hour. Weekends and holidays were excluded from the estimation database.[10]

We tested a variety of weather variables in an attempt to determine which set best explains usage on event-like non-event days. This process and its results are explained in Appendix A.

[10] 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.

3.2 Description of methods

3.2.1 Regression Model

The model shown below was separately estimated for each enrolled customer. Table 3.1 describes the terms included in the equation.

$$
\begin{aligned}
Q_t &= a + \sum_{Evt=1}^{E} \sum_{i=1}^{24} (b_{i,Evt}^{DBP} \times h_{i,t} \times DBP_t) + \sum_{i=1}^{24} (b_i^{MornLoad} \times h_{i,t} \times MornLoad_{i,t}) \\
&+ \sum_{DR} \sum_{i=1}^{24} (b_i^{DR} \times h_{i,t} \times OtherEvt^{DR}{}_{i,t}) + \sum_{i=1}^{24} (b_i^{Weather} \times h_{i,t} \times Weather_t) + \sum_{i=2}^{24} (b_i^{MON} \times h_{i,t} \times MON_t) \\
&+ \sum_{i=2}^{24} (b_i^{FRI} \times h_{i,t} \times FRI_t) + \sum_{i=2}^{24} (b_i^{SUMMER} \times h_{i,t} \times SUMMER_t) + \sum_{i=2}^{24} (b_i^{h} \times h_{i,t}) \\
&+ \sum_{i=2}^{5} (b_i^{DTYPE} \times DTYPE_{i,t}) + \sum_{i=6}^{10} (b_i^{MONTH} \times MONTH_{i,t}) + e_t
\end{aligned}
$$

Table 3.1: Descriptions of Terms included in the Ex Post Regression Equation

Variable Name / Term	Variable / Term Description
Q_t	the demand in hour *t* for a customer enrolled in DBP prior to the last event date
The various *b*'s	the estimated parameters
$h_{i,t}$	a dummy variable for hour *i*
DBP_t	an indicator variable for program event days
$Weather_t$	the weather variables selected using our model screening process
E	the number of event days that occurred during the program year
$MornLoad_t$	a variable equal to the average of the day's load in hours 1 through 10
$OtherEvt^{DR}{}_t$	equals one on the event days of other demand response programs in which the customer is enrolled
MON_t	a dummy variable for Monday
FRI_t	a dummy variable for Friday
$SUMMER_t$	a dummy variable for the summer pricing season[11]
$DTYPE_{i,t}$	a series of dummy variables for each day of the week
$MONTH_{i,t}$	a series of dummy variables for each month
e_t	the error term.

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

[11] The summer pricing season is July through September for SCE, May through September for SDG&E, and May through October for PG&E.

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

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

3.2.2 Development of Uncertainty-Adjusted Load Impacts

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

Specifically, we added the variances of the estimated load impacts across the customers 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 each of the 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 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 37.6 kW for PG&E's program, 75.8 kW for SCE's program, 90 kW for SDG&E's DBP-DA (Navy) program, and 4.4 MW for SDG&E's DBP-DO program.[12]

4.1 PG&E Load Impacts

4.1.1 Average Hourly Load Impacts by Industry Group and LCA

Table 4.1 summarizes average hourly reference loads and load impacts at the program level for each of PG&E's DBP events. Results are summarized separately across all customers (in the top panel) and those who were not dually enrolled in another DR program (in the bottom panel). The average hourly load impact across the events during which all DBP customers were called (7/1, 7/3, and 9/9) was 35.8 MW, or an average of 4.3 percent of the total reference load. The load impacts were highest during the July 1st event, at 43.6 MW (5.2 percent of the reference load). The vast majority of the load impacts came from customers who were dually enrolled in another DR program. These load impacts are similar to those of the previous program year, in which load impacts averaged 37.8 MW (or 4.6 percent) across three events. Note that some results have been removed due to confidentiality concerns.

Table 4.1: Average Hourly Load Impacts by Event, *PG&E*

Customer Group	Event	Date	Day of Week	Estimated Reference Load (MW)	Observed Load (MW)	Estimated Load Impact (MW)	% LI
All	1	6/7/13	Friday				
	2	7/1/13	Monday	835.7	792.1	43.6	5.2%
	3	7/3/13	Wednesday	812.9	780.1	32.9	4.0%
	4	8/19/13	Monday				
	5	9/9/13	Monday	829.0	798.0	31.0	3.7%
	6	9/10/13	Tuesday	73.4	69.3	4.1	5.5%
	Average when all called			**825.9**	**790.0**	**35.8**	**4.3%**
	Std. dev. When all called					**6.8**	**0.8%**
Enrolled in DBP Only	1	6/7/13	Friday				
	2	7/1/13	Monday	543.2	542.2	1.0	0.2%
	3	7/3/13	Wednesday	532.8	531.8	1.0	0.2%
	4	8/19/13	Monday				
	5	9/9/13	Monday	551.0	549.3	1.7	0.3%
	6	9/10/13	Tuesday	39.4	39.4	0.0	0.0%
	Average when all called			**542.3**	**541.1**	**1.2**	**0.2%**
	Std. dev. When all called					**0.4**	**0.1%**

Table 4.2 compares the bid quantities to the estimated load impacts for each event. Across the three events during which all customers were called, the bid amount averaged approximately 41.2 MW, while the estimated average hourly load impact was

[12] We used one customer to calculate the per-customer load impact for SDG&E's DBP-DO program. The program includes three service accounts from a single customer, but these service accounts are aggregated for settlement purposes.

35.8 MW. The average bid realization rate (i.e., the estimated load impacts as a percentage of bid amounts) across all event hours was 87 percent. The bid realization rate was somewhat lower for customers enrolled only in DBP, averaging 30 percent across the three event days.[13]

Table 4.2: Average Hourly Bid Realization Rates by Event, *PG&E*

Customer Group	Event	Date	Day of Week	Average Bid Quantity (MW)	Estimated Load Impact (MW)	LI as % of Bid Amount
All	1	6/7/13	Friday			
	2	7/1/13	Monday	34.7	43.6	126%
	3	7/3/13	Wednesday	42.2	32.9	78%
	4	8/19/13	Monday			
	5	9/9/13	Monday	46.6	31.0	67%
	6	9/10/13	Tuesday	6.0	4.1	68%
	Average when all called			**41.2**	**35.8**	**87%**
Enrolled in DBP Only	1	6/7/13	Friday			
	2	7/1/13	Monday	2.9	1.0	36%
	3	7/3/13	Wednesday	6.1	1.0	16%
	4	8/19/13	Monday			
	5	9/9/13	Monday	3.1	1.7	54%
	6	9/10/13	Tuesday	0.0	0.0	n/a
	Average when all called			**4.0**	**1.2**	**30%**

Table 4.3 summarizes average hourly DBP load impacts at the program level (i.e., including both bidders and non-bidders) and by industry group for each of PG&E's event days. The Manufacturing industry group accounted for the largest share of the load impacts, with a 26.6 MW average event-hour load reduction.

[13] We have explored the differences between the estimated ex post load impacts and bid amounts for 7/1 and 7/3 (the load impacts for those dates may appear to be reversed) and are confident that the estimated ex post load impacts are reasonable given our interpretation of the observed data. Discrepancies are due to outcomes for a handful of service accounts, some of which have unpredictable loads.

Table 4.3: Average Event-day Hourly Load Impacts – PG&E DBP, *by Industry Group*

Industry Group	# of Service Accounts	Estimated Reference Load (MW)	Observed Load (MW)	Estimated Load Impact (MW)	% LI
Agriculture, Mining, & Construction	104	34.4	34.2	0.1	0.4%
Manufacturing	198	341.6	315.0	26.6	7.8%
Wholesale, Transportation, & Other Utilities	135	73.5	67.0	6.6	8.9%
Retail Stores	96	16.8	16.7	0.1	0.9%
Offices, Hotels, Health, Services	264	246.1	244.7	1.4	0.6%
Schools	30	19.4	19.4	0.0	0.0%
Entertainment, Other Services, Government	116	92.4	91.4	1.0	1.0%
Other or Unknown					
Total	**952**	**825.9**	**790.0**	**35.8**	**4.3%**

Table 4.4 summarizes load impacts by local capacity area (LCA), showing that the highest share of the load impacts came from service accounts not associated with any LCA. Note that some results have been removed due to confidentiality concerns.

Table 4.4: Average Event-day Hourly Load Impacts – PG&E DBP, *by LCA*

Local Capacity Area	# of Service Accounts	Estimated Reference Load (MW)	Observed Load (MW)	Estimated Load Impact (MW)	% LI
Greater Bay Area	442	381.6	378.2	3.4	0.9%
Greater Fresno					
Humboldt					
Kern					
Northern Coast					
Not in any LCA	273	344.3	313.3	31.0	9.0%
Sierra					
Stockton					
Total	**952**	**825.9**	**790.0**	**35.8**	**4.3%**

4.1.2 Hourly Load Impacts

Table 4.5 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 for customers enrolled at the time of either event. The table only includes data and results from the three events during which all DBP customers were called. The hourly load impact on the average event day ranges from 29.8 MW to 37.7 MW.

PG&E has two very different types of customers in DBP: those who are dually enrolled in another DR program (Base Interruptible Program (BIP) or an aggregator program) and those who are not. The dually enrolled customers, particularly those enrolled in both DBP and BIP, tend to be larger and much more demand responsive than the customers who are only enrolled in DBP. On average, dually enrolled customers account for 34.6 MW of the 35.8 MW total DBP load impact.

Table 4.5: DBP Hourly Load Impacts for the Average Event Day, *PG&E*

Hour Ending	Estimated Reference Load (MWh/hour)	Observed Event Day Load (MWh/hour)	Estimated Load Impact (MWh/hour)	Weighted Average Temperature (°F)	Uncertainty Adjusted Impact (MWh/hr)- Percentiles				
					10th%ile	30th%ile	50th%ile	70th%ile	90th%ile
1	660.0	659.0	1.0	69.7	-3.9	-1.0	1.0	3.0	5.9
2	655.0	654.1	0.9	68.8	-4.0	-1.1	0.9	2.9	5.8
3	650.7	649.9	0.8	67.8	-4.1	-1.2	0.8	2.9	5.8
4	652.5	651.1	1.3	66.9	-3.6	-0.7	1.3	3.3	6.2
5	668.4	666.9	1.5	66.1	-3.4	-0.5	1.5	3.6	6.5
6	698.4	697.9	0.5	65.6	-4.4	-1.5	0.5	2.5	5.4
7	736.7	739.7	-3.0	65.3	-7.9	-5.0	-3.0	-1.0	1.9
8	766.8	768.4	-1.6	67.1	-6.5	-3.6	-1.6	0.4	3.3
9	798.0	800.2	-2.2	70.4	-7.1	-4.2	-2.2	-0.2	2.7
10	825.5	827.7	-2.3	74.2	-7.2	-4.3	-2.3	-0.3	2.7
11	845.5	845.8	-0.3	78.2	-5.2	-2.3	-0.3	1.7	4.6
12	857.3	845.9	11.4	82.0	6.5	9.4	11.4	13.5	16.4
13	847.6	812.0	35.6	85.1	30.7	33.6	35.6	37.6	40.5
14	855.7	819.3	36.3	87.9	31.4	34.3	36.3	38.4	41.3
15	853.7	816.0	37.7	89.6	32.8	35.7	37.7	39.7	42.7
16	841.1	804.1	37.0	90.2	32.1	35.0	37.0	39.1	42.0
17	832.2	795.4	36.8	89.9	31.8	34.8	36.8	38.8	41.8
18	809.3	772.0	37.3	88.7	32.3	35.2	37.3	39.3	42.2
19	790.6	754.6	36.0	85.4	31.1	34.0	36.0	38.0	41.0
20	776.8	747.0	29.8	81.1	24.9	27.8	29.8	31.8	34.7
21	765.7	743.2	22.5	77.7	17.6	20.5	22.5	24.5	27.4
22	750.2	735.2	15.0	75.7	10.1	13.0	15.0	17.0	20.0
23	731.8	720.5	11.3	74.2	6.4	9.3	11.3	13.3	16.2
24	715.9	708.5	7.5	72.8	2.5	5.4	7.5	9.5	12.4
By Period:	**Estimated Reference Energy Use (MWh)**	**Observed Event Day Energy Use (MWh)**	**Estimated Change in Energy Use (MWh)**	**Cooling Degree Hours (Base 75° F)**	**Uncertainty Adjusted Impact (MWh/hour) - Percentiles**				
					10th	**30th**	**50th**	**70th**	**90th**
Daily	18,385	18,034	351	111.5	n/a	n/a	n/a	n/a	n/a

Figure 4.1 illustrates the hourly reference load, observed load, and load impacts for the average DBP event day, including only the three events during which all DBP customers were called. The scale for the load impacts is shown on the right-side y-axis. Figure 4.2 shows the variability of estimated load impacts across the six event days. Note that two event days have been removed from the chart due to confidentiality concerns.

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 for the Average Event Day, *PG&E*

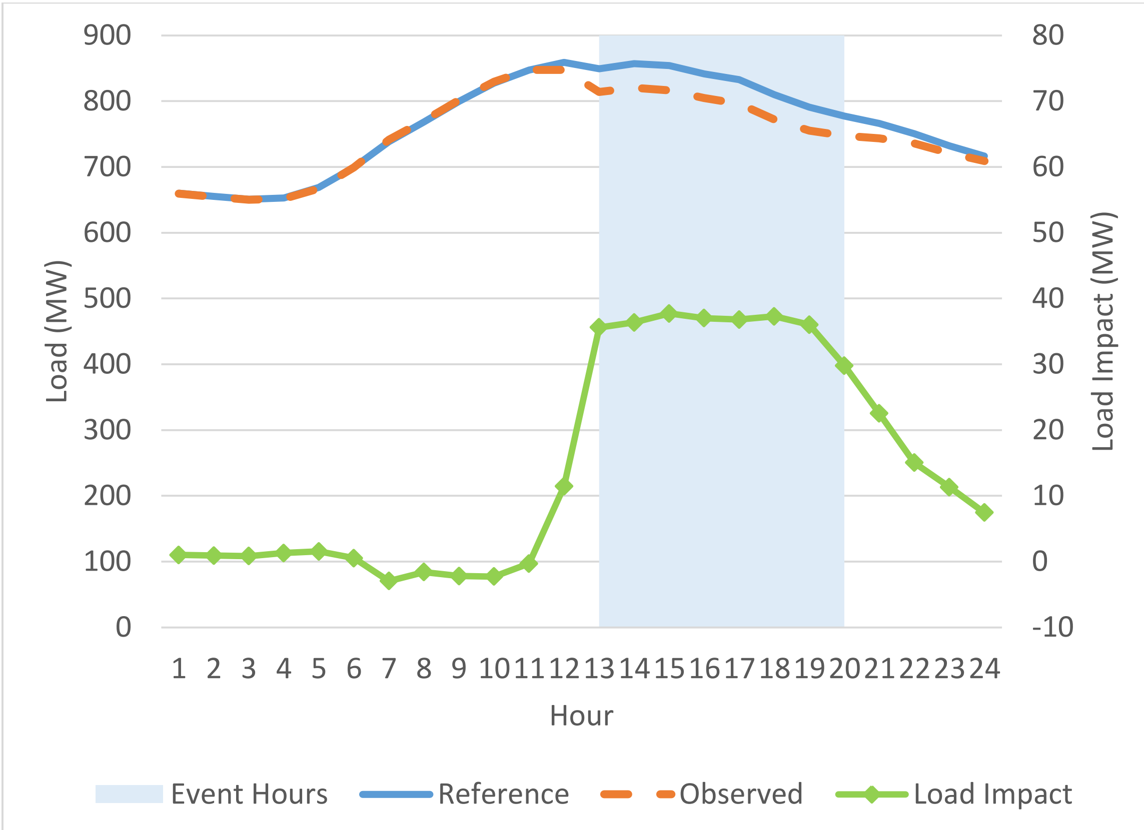
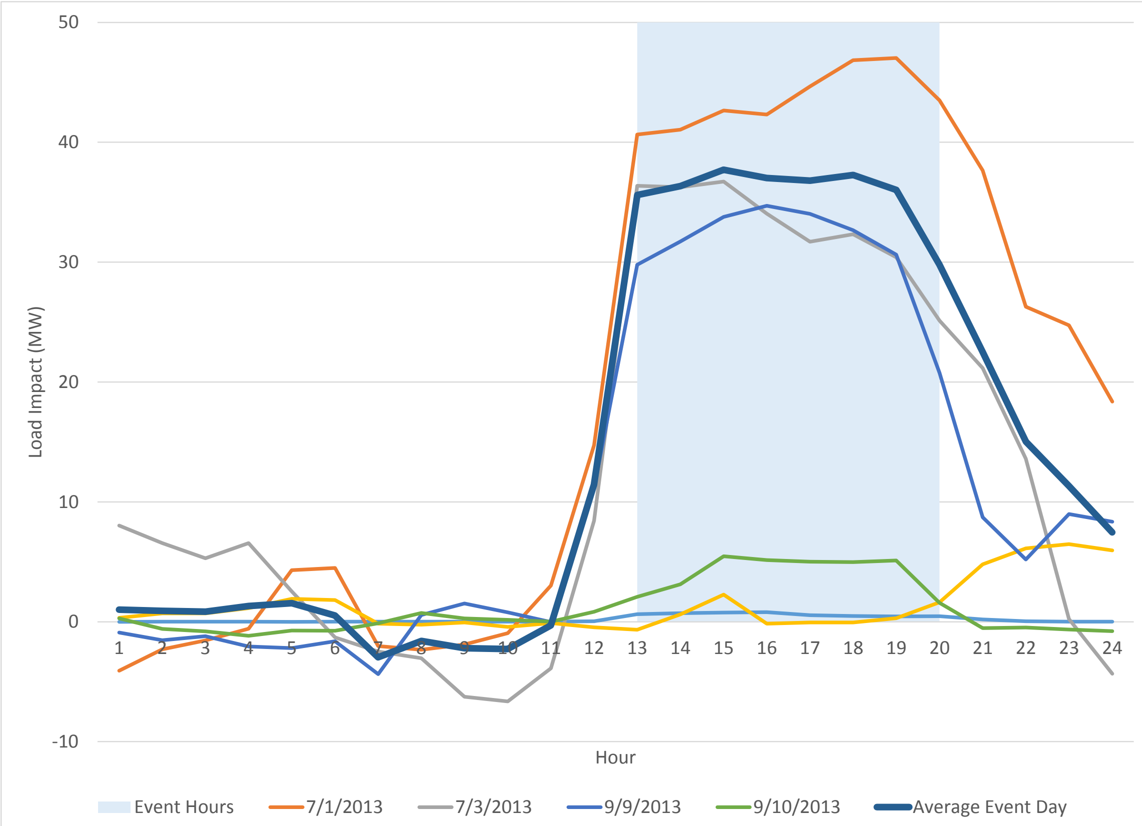


Figure 4.2: Hourly Load Impacts by Event, *PG&E DBP*



4.2 SCE Load Impacts

4.2.1 Average Hourly Load Impacts by Industry Group and LCA

Table 4.6 summarizes average hourly reference loads and load impacts at the program level for each of SCE's eight DBP events. The top panel shows the results for all DBP customers and the bottom panel shows the results for customers who were not dually enrolled in another DR program. Across all events, the average hourly load impact was approximately 99.5 MW. The load impacts varied across event days, with a low of 90.6 MW, a high of 111.4 MW, and a standard deviation of 7.6 MW. On average, the load impacts were 10 percent of the total reference load. The vast majority of the load impact came from customers dually enrolled in another DR program.

Table 4.6: Average Hourly Load Impacts by Event, *SCE*

Customer Group	Event	Date	Day of Week	Estimated Reference Load (MW)	Observed Load (MW)	Estimated Load Impact (MW)	% LI
All	1	6/3/2013	Monday	970	870	100.6	10.4%
	2	6/28/2013	Friday	1,011	900	111.4	11.0%
	3	7/2/2013	Tuesday	1,003	912	90.6	9.0%
	4	8/28/2013	Wednesday	1,014	916	98.7	9.7%
	5	9/9/2013	Monday	973	877	96.0	9.9%
			Average	**994**	**895**	**99.5**	**10.0%**
			Std. Dev.			**7.6**	**0.8%**
Enrolled in DBP Only	1	6/3/2013	Monday	563	555	8.2	1.4%
	2	6/28/2013	Friday	596	592	3.7	0.6%
	3	7/2/2013	Tuesday	603	596	6.6	1.1%
	4	8/28/2013	Wednesday	585	581	4.0	0.7%
	5	9/9/2013	Monday	559	553	6.4	1.1%
			Average	**581**	**575**	**5.8**	**1.0%**
			Std. Dev.			**1.9**	**0.3%**

Table 4.7 compares the bid quantities to the estimated load impacts for each event. Across all events, the bid amount averaged approximately 134 MW, while the estimated average hourly load impact was 99.5 MW. The average bid realization rate (estimated load impacts as a percentage of bid amounts) across all event hours was 74.1 percent. The bottom panel of Table 4.7 shows that the bid realization rate is quite low (25 percent) for the customers who were not enrolled in another DR program.

Table 4.7: Average Hourly Bid Realization Rates by Event, *SCE*

Customer Group	Event	Date	Day of Week	Average Bid Quantity (MW)	Estimated Load Impact (MW)	LI as % of Bid Amount
All	1	6/3/2013	Monday	141.7	100.6	71.0%
	2	6/28/2013	Friday	133.5	111.4	83.4%
	3	7/2/2013	Tuesday	140.6	90.6	64.4%
	4	8/28/2013	Wednesday	116.2	98.7	85.0%
	5	9/9/2013	Monday	139.2	96.0	69.0%
			Average	**134.2**	**99.5**	**74.1%**
Enrolled in DBP Only	1	6/3/2013	Monday	25.5	8.2	32.0%
	2	6/28/2013	Friday	24.2	3.7	15.3%
	3	7/2/2013	Tuesday	22.6	6.6	29.1%
	4	8/28/2013	Wednesday	21.0	4.0	19.1%
	5	9/9/2013	Monday	22.7	6.4	28.0%
			Average	**23.2**	**5.8**	**24.8%**

Tables 4.8 and 4.9 summarize average hourly load impacts for the average event by industry group and LCA. Table 4.9 includes additional rows of data that summarize the load impacts for South Orange County and South of Lugo. Manufacturing service accounts accounted for the largest share of the load impacts. By region, the highest share of the average load impact came from the LA Basin. Note that some results have been removed due to confidentiality concerns.

Table 4.8: Average Event-day Hourly Load Impacts – SCE DBP, *by Industry Group*

Industry Group	# of Service Accounts	Estimated Reference Load (MW)	Observed Load (MW)	Estimated Load Impact (MW)	% LI
Agriculture, Mining, & Construction	28	25	23	2.4	9.6%
Manufacturing	328	558	474	84.2	15.1%
Wholesale, Transportation, & Other Utilities	146	65	54	11.1	17.1%
Retail Stores	185	51	51	0.5	0.9%
Offices, Hotels, Health, Services	237	142	141	1.4	1.0%
Schools	288	29	28	0.3	1.1%
Entertainment, Other Services, Government	100	125	125	-0.4	-0.3%
Total	**1,312**	**994**	**895**	**99.5**	**10.0%**

Table 4.9: Average Event-day Hourly Load Impacts – SCE DBP, *by LCA*

Local Capacity Area	# of Service Accounts	Estimated Reference Load (MW)	Observed Load (MW)	Estimated Load Impact (MW)	% LI
LA Basin					
Outside LA Basin					
Ventura					
Total	**1,312**	**994**	**895**	**99.5**	**10.0%**
South Orange County	200	92	90	1.8	2.0%
South of Lugo	356	155	150	4.8	3.1%

4.2.2 Hourly Load Impacts

Table 4.10 presents hourly load impacts at the program level for the average DBP event in the manner required by the Protocols. The hourly load impact on the average event day ranges from 90 MW to 105 MW.

Table 4.10: DBP Hourly Load Impacts for the Average Event Day, *SCE*

Hour Ending	Estimated Reference Load (MWh/hour)	Observed Event Day Load (MWh/hour)	Estimated Load Impact (MWh/hour)	Weighted Average Temperature (°F)	Uncertainty Adjusted Impact (MWh/hr)- Percentiles				
					10th%ile	30th%ile	50th%ile	70th%ile	90th%ile
1	807.6	803.9	3.6	71.9	-7.5	-0.9	3.6	8.2	14.8
2	797.2	791.5	5.7	70.8	-5.5	1.1	5.7	10.2	16.8
3	790.3	788.9	1.4	70.0	-9.8	-3.2	1.4	5.9	12.5
4	795.8	797.5	-1.6	69.3	-12.8	-6.2	-1.6	2.9	9.5
5	817.7	820.9	-3.3	68.5	-14.4	-7.8	-3.3	1.3	7.9
6	862.1	864.6	-2.5	67.8	-13.6	-7.0	-2.5	2.1	8.6
7	911.5	911.0	0.5	67.2	-10.6	-4.1	0.5	5.1	11.6
8	950.7	948.5	2.2	67.2	-9.0	-2.4	2.2	6.7	13.3
9	987.9	989.8	-1.8	69.2	-13.0	-6.4	-1.8	2.7	9.3
10	1,013.8	1,013.4	0.4	72.4	-10.7	-4.1	0.4	5.0	11.6
11	1,033.0	1,027.4	5.6	75.6	-5.5	1.0	5.6	10.1	16.7
12	1,038.2	1,007.7	30.5	78.7	19.4	26.0	30.5	35.1	41.6
13	1,035.5	936.7	98.8	81.1	87.7	94.3	98.8	103.4	109.9
14	1,037.8	935.1	102.7	82.8	91.6	98.1	102.7	107.2	113.8
15	1,032.7	931.0	101.7	84.1	90.6	97.2	101.7	106.3	112.8
16	1,019.9	915.0	104.8	84.5	93.7	100.3	104.8	109.4	115.9
17	1,002.8	900.8	102.0	84.3	90.9	97.5	102.0	106.5	113.1
18	971.5	872.4	99.1	83.7	88.0	94.6	99.1	103.7	110.2
19	932.3	836.0	96.3	82.3	85.2	91.8	96.3	100.9	107.5
20	922.3	831.9	90.4	80.4	79.2	85.8	90.4	94.9	101.5
21	914.9	856.4	58.6	77.8	47.4	54.0	58.6	63.1	69.7
22	897.6	860.8	36.8	75.4	25.7	32.3	36.8	41.4	47.9
23	871.9	843.5	28.4	73.9	17.3	23.9	28.4	33.0	39.6
24	850.1	829.0	21.2	72.8	10.0	16.6	21.2	25.7	32.3
By Period:	Estimated Reference Energy Use (MWh)	Observed Event Day Energy Use (MWh)	Estimated Change in Energy Use (MWh)	Cooling Degree Hours (Base 75° F)	Uncertainty Adjusted Impact (MWh/hour) - Percentiles				
					10th	30th	50th	70th	90th
Daily	22,295	21,314	981	70.7	n/a	n/a	n/a	n/a	n/a

Figure 4.3 illustrates the hourly reference load, observed load, and load impact for the average DBP event. The scale for the hourly load impacts is shown on the right-hand side of the figure. Figure 4.4 shows the variability of estimated load impacts across events. The variation in load impacts across events was somewhat less than we found during the previous evaluation.

Figure 4.3: DBP Load Impacts for the Average Event Day, *SCE*

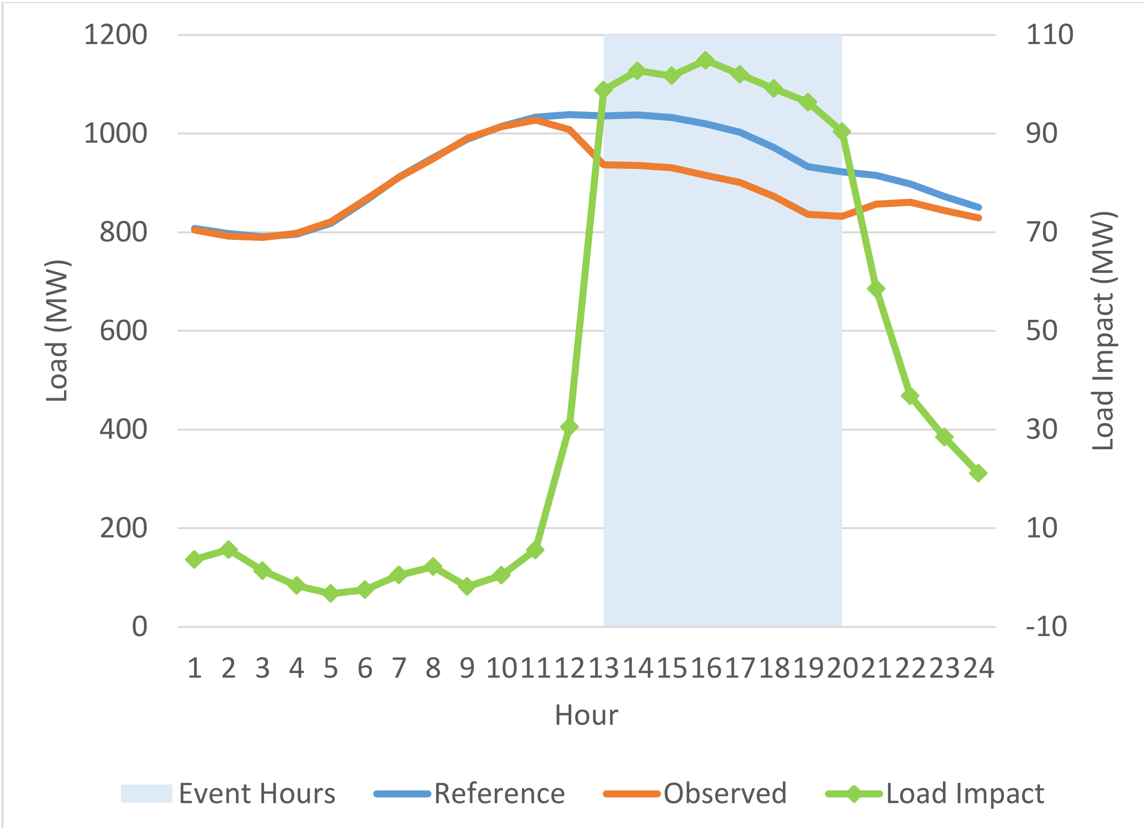
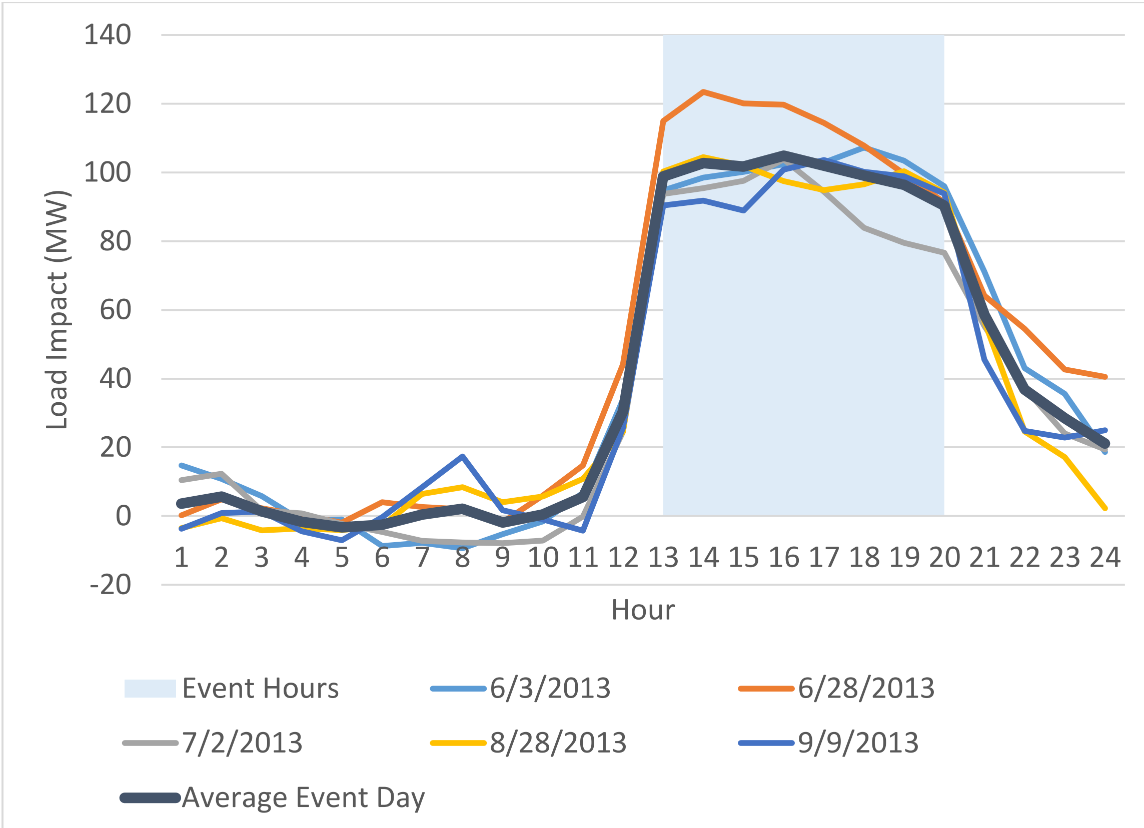


Figure 4.4: Hourly Load Impacts by Event, *SCE DBP*



4.3 SDG&E Load Impacts

4.3.1 Average Hourly Load Impacts

Table 4.11 summarizes average hourly reference loads and load impacts at the program level for each of SDG&E's three DBP events. The last row of the table contains the average outcome across the two day-of notice events. The DO customer averaged a 4.5 MW, or 39.4 percent load impact across its two events. The second event (September 5) had a substantially higher load impact than the first event. The DA customer reduced load by an average of 5.7 MW (14.2 percent) during its sole event.

Our estimate of the DBP-DA (Navy) load impact is considerably higher than the load impact that is estimated using the program baseline method, which estimated an average event-hour load impact of less than 1 MW and resulted in the customer receiving a DBP incentive payment for only the second event hour. A review of the customer data for the September 6 event day and surrounding days does not provide conclusive evidence in favor of either estimate. The event-day load is somewhat low relative to surrounding days, but spikes in the hour prior to the event. Because the day-of baseline adjustment does not incorporate the hour immediately preceding the event period, the resulting adjusted baseline is comparatively low.

The customer's bid may cast some doubt on our estimated ex post load impact. That is, one of the customer's eight service accounts was responsible for the majority of the estimated load impact (4.1 MW of the 4.5 total MW). However, the customer only bid a 1 MW load reduction in each hour for this service account. This may indicate that the settlement load impact is closer to the true load impact than the ex post estimate.

Table 4.11: Average Hourly Load Impacts by Event, *SDG&E*

Event	Date	Day of Week	Estimated Reference Load (MW)	Observed Load (MW)	Estimated Load Impact (MW)	% LI
1 (DO)	8/30/2013	Friday	9.9	7.0	2.9	29.4%
2 (DO)	9/5/2013	Thursday	12.7	6.7	6.0	47.1%
3 (DA)	9/6/2013	Friday	40.5	34.7	5.7	14.2%
Average DO Event			**11.3**	**6.9**	**4.5**	**39.4%**

Table 4.12 compares the bid quantities to the estimated load impacts for each event. The DO customer bid 5 MW for each event and averaged 4.5 MW of response across the two days for an average bid realization rate of 89 percent. The DA customer bid 3.1 MW but reduced load by 5.7 MW, which amounts to a 185 percent bid realization rate.

Table 4.12: Average Hourly Bid Realization Rates by Event*, SDG&E*

Event	Date	Day of Week	Average Bid Quantity (MW)	Estimated Load Impact (MW)	LI as % of Bid Amount
1 (DO)	8/30/2013	Friday	5.0	2.9	58%
2 (DO)	9/5/2013	Thursday	5.0	6.0	120%
3 (DA)	9/6/2013	Friday	3.1	5.7	185%
Average DO Event			**5.0**	**4.5**	**89%**

4.3.2 Hourly Load Impacts

Recall that SDG&E has two DBP programs, each of which consists of multiple service accounts for one customer. Table 4.13 presents hourly load impacts at the program level for the September 5 DBP-DO event day, which had the longer event window (hours ending 14 through 17) of the two DBP-DO events. The hourly load impact on the average event day ranges from 5.1 MW to 7.0 MW.

Table 4.13: DBP Hourly Load Impacts for the September 5th Event Day, *SDG&E DO*

These results have been removed due to confidentiality concerns.

Table 4.14 presents hourly load impacts at the program level for the September 6 DBP-DA event, which was the only event day for that program. The event included hours-ending 14 through 17. The hourly load impact on the average event day ranges from 3.8 MW to 7.5 MW.

Table 4.14: DBP Hourly Load Impacts for the September 6th Event Day, *SDG&E DA*

These results have been removed due to confidentiality concerns.

Figures 4.5 and 4.6 illustrate the hourly reference load, observed load, and load impact for the DO and DA DBP September event days. The scale for the load impacts is on the right-hand side of the figure.

Figure 4.5: DBP September 5 Load Impacts, *SDG&E DO*

These results have been removed due to confidentiality concerns.

Figure 4.6: DBP September 6 Load Impacts, *SDG&E DA*

These results have been removed due to confidentiality concerns.

4.4 Summary 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.

In the sub-sections below, we summarize *total* load impacts for TA/TI and AutoDR. These are simply the sum of the estimated load impacts for customers in each program, as estimated using the methods described in Section 3.2.1.

PG&E

TA/TI

According to data provided by PG&E, nine DBP service accounts participated in the TA/TI program. However, no more than one of these service accounts submitted a bid during each event day.

Table 4.15 shows the event-specific load impact for the TA/TI participants. These customers averaged a 9.7 percent load impact across the three "full" event days (i.e., when the entire DBP program was notified), with the highest response of 2.6 MW occurring on the July 1 event day. The rightmost column ("Approved MW for bidders") shows the total MW approved following the TA/TI DR test.

Table 4.15: Average Hourly Load Impacts by Event, *PG&E TA/TI*

Table removed due to confidentiality concerns.

AutoDR

According to data provided by PG&E, an average of 88 DBP service accounts participated in the AutoDR program. During any one event when all DBP customers were notified, a maximum of 55 of these submitted a bid. Table 4.16 shows the average hourly load impact for the AutoDR participants, which was 16.1 MW, or 19.5 percent of the reference load. Note that some results were removed due to confidentiality concerns.

Table 4.16: Average Hourly Load Impacts by Event, *PG&E AutoDR*

Event Date	Number of Notified SAIDs	Number of Bidding SAIDs	Estimated Reference Load (MW)	Observed Load (MW)	Estimated Load Impact (MW)	% Load Impact	Approved MW for Bidders
7/1/2013	89	53	86.4	68.5	17.9	20.7%	43.0
7/3/2013	89	51	80.8	68.9	11.9	14.8%	43.0
8/19/2013							
9/9/2013	87	55	80.9	62.5	18.4	22.8%	42.5
9/10/2013							
Average when all called	**88**	**53**	**82.7**	**66.6**	**16.1**	**19.5%**	**42.8**

SCE

TA/TI

Table 4.17 shows the DBP load impacts provided by SCE's TA/TI service accounts for each event. An average of 72 of SCE's DBP service accounts participated in TA/TI, with an average of 45 participants submitting a bid during each event. DBP participants include both individual and load accounts, which can place a single bid for up to 25 service accounts. The load impacts for this group are considerably lower for the September 9 event day compared to the prior event days. This is because the largest responder did not respond during the final event. This service account had averaged an 18.7 MW load impact in the first four events.

Table 4.17: Average Hourly Load Impacts by Event, *SCE TA/TI*

Event Date	Number of SAIDs	Number of Bidding SAIDs	Estimated Reference Load (MW)	Observed Load (MW)	Estimated Load Impact (MW)	% Load Impact	Approved MW for Bidders
6/3/2013	67	42	61.4	41.4	20.0	32.6%	21.7
6/28/2013	75	55	67.7	48.6	19.1	28.2%	27.8
7/2/2013	74	38	66.0	46.5	19.5	29.6%	21.2
8/28/2013	73	39	57.0	37.4	19.5	34.3%	20.8
9/9/2013	73	52	56.5	55.2	1.3	2.3%	22.5
Average	**72**	**45**	**61.7**	**45.8**	**15.9**	**25.8%**	**22.8**

AutoDR

Table 4.18 shows the total DBP load impacts for SCE's AutoDR participants. Approximately 148 DBP service accounts participated in AutoDR, with an average of 119 participants bidding during each event. The percentage load impacts are uniformly high across events, averaging 22 percent, or 28 MW.

Table 4.18: Average Hourly Load Impacts by Event, *SCE AutoDR*

Event Date	Number of SAIDs	Number of Bidding SAIDs	Estimated Reference Load (MW)	Observed Load (MW)	Estimated Load Impact (MW)	% Load Impact	Approved MW for Bidders
6/3/2013	161	131	126.4	93.7	32.8	25.9%	64.9
6/28/2013	145	117	123.7	86.2	37.5	30.3%	61.8
7/2/2013	145	118	123.2	103.8	19.4	15.7%	63.0
8/28/2013	145	118	136.1	113.8	22.2	16.3%	64.5
9/9/2013	145	112	129.2	101.8	27.4	21.2%	60.4
Average	**148**	**119**	**127.7**	**99.9**	**27.9**	**21.8%**	**62.9**

5. Baseline Analysis

5.1 Objectives

Decision 12-04-045 (pages 63-4) issued by the CPUC on April 19, 2012 requires a baseline analysis for DBP. Baselines are the basis for DBP payments to customers, as they represent estimates of the hourly energy that the customer would have used in the absence of a DBP event. Specifically, DBP uses a 10-in-10 baseline method, including an optional day-of adjustment based on the ratio of the current day's pre-event usage level to the usage level in the same period for the 10-in-10 baseline.[14] The tariff language currently limits this adjustment to +/- 20 percent.[15] The Decision raises the cap for Capacity Bidding Program to 40% for the individual 10-in-10 baseline, but requires further study of the issue, which this section represents.

The alternative baseline methodologies that we examined include 10-in-10 unadjusted baselines, and day-of adjusted baselines with cap percentages of 20, 30, 40, and 50 percent, as well as an uncapped adjustment. Since there is no third party aggregation for DBP, the "aggregated" baseline is no different than the individual baseline and thus requires no additional analysis.

Two sets of days are examined: PY2013 event days; and a set of event-like non-event days.[16] For the event days, the baselines are compared 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. 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 "true" baseline load to which the alternative program baseline loads are compared.

For the event-like non-event days, the observed loads on those event-like days serve as "known" baselines, which may then be compared to all of the relevant alternative baseline methods.

[14] The 10-in-10 baseline is calculated as the average energy usage for each hour across the ten most recent non-event weekdays. The day-of adjustment is calculated using average hourly consumption in the first three hours of the four hours prior to the event period.

[15] SDG&E's DBP programs limit the adjustment to +/- 40 percent.

[16] See Section A.1.1 for a description of how these days were selected. A list of the event-like non-event days by utility is contained in Table A.2.

5.2 Measures of baseline performance

Performance of the alternative baseline methods was measured primarily by two statistics measuring the baseline's *accuracy* and *bias*. The performance measures are calculated using the average across the event hours of each event day for each customer service account. That is, the observations used in constructing the performance statistics represent outcomes on a customer's event day.[17] The statistics combine information across customers of various types, and events.

Baseline **bias** was measured using the *median percentage error ("MPE")*, where the percentage error is defined as the *difference* between the baseline measure in question and the "true" baseline load (the regression-based baseline for event days or the observed load for event-like days), divided by the *level* of the true baseline. Therefore a positive MPE indicates an *upward* bias (or a tendency to overpay customers for load reductions) and a negative MPE is associated with a *downward* bias (or a tendency to underpay customers). Note that MPE is typically used to refer to "*mean* percentage error." In this study, we use the median in place of the mean because there are outliers (e.g., percentage errors in excess of 500 percent due to very low observed loads during the hours in question) that limit the usefulness of the mean values. The percentage error for each customer-event day is calculated as follows:

Percentage error = $(L^P_d – L^A_d) / L^A_d$,

where in this case

L^P_d is one of the alternative *predicted* (program) average baseline load on customer-event day *d*;
L^A_d is the "true" (based on regression results or observed loads) baseline load on customer-event day *d*; and
n is the total number of observations (e.g., the number of customer-event days).

The MPE is the 50th percentile value of the percentage errors over the relevant observations (e.g., customers who selected the day-of adjustment on actual event days).

Baseline **accuracy** (relative to the true baseline) was measured using the *median absolute percentage error, or MAPE*.[18] 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 true baseline. MAPE is calculated using the same formula

[17] Baselines for customers that are part of an aggregation are calculated using the sum of the lead (or parent) and subordinate (or child) service accounts.
[18] As with MPE, MAPE is typically used in reference to mean, rather than median absolute percentage errors. The existence of outliers affects the ability to usefully interpret mean values for both measures.

as MPE, with one exception: MAPE uses the absolute value of the difference between the baseline and regression-based reference load or observed load.

While our primary focus is on *percentage* baseline errors, we also present a figure showing the distribution of errors expressed in kWh.

5.3 Data

We examined only customers who submitted a bid for at least one event day during the 2013 program year. Results were calculated for each customer event day by averaging the values across each customer's event hours for every event (and event-like) day. Thus, the unit of observation is a customer event day (i.e., each customer will have as many observations as there are event or event-like days).

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 and observed baselines, with results reported by customer type (all customers or only those who selected the day-of adjustment) and event type (all studied events, only actual events, and only event-like days). Only customers who submitted a bid for at least one PY2013 event day were included in the analysis.[19]

The results show that adjusted baselines tend to be more accurate than unadjusted baselines, but the presence or size of the cap does not have a substantial effect on accuracy. For example, the median unadjusted baseline error was 9.0 percent when examining all DBP customers on the PY2013 event days. This error can be reduced to 5.9 to 6.1 percent using a day-of adjustment, with the best performance achieved for the 20 percent cap on the baseline adjustment. The improvement in baseline accuracy resulting from the day-of adjustment is similar whether one examines all DBP customers or only those who selected it during PY2013. The baseline accuracy results were also similar whether we examine actual event days or event-like non-event days, though the accuracy tended to be better when examining the event-like days.

[19] The "# of Cust.-Events" column indicates the number of observations, which is the number of bidding customers multiplied by the number of event and/or event-like days being examined.

Table 5.1: Accuracy of Alternative Baselines, *PG&E DBP*
(*Median Absolute Percentage Error*)

Event Type	Customer Group	# of Cust.-Events	Baseline Adjustment Examined					
			Unadj.	20%	30%	40%	50%	No Cap
All	All	1,658	9.0%	5.9%	6.1%	6.1%	6.1%	6.1%
All	Selected Adj.	1,423	8.7%	5.8%	6.2%	6.1%	6.1%	6.1%
Actual	All	664	9.8%	6.5%	6.5%	6.6%	6.7%	6.7%
Actual	Selected Adj.	429	9.4%	6.7%	6.9%	7.1%	7.1%	7.2%
Event-like	All	994	8.5%	5.5%	5.8%	5.8%	5.7%	5.7%
Event-like	Selected Adj.	994	8.5%	5.5%	5.8%	5.8%	5.7%	5.7%

Table 5.2 presents results for the typical *bias* of the alternative baselines. In all cases, the MPE results indicate a tendency for baselines to be *understated* (i.e., the calculated baseline is less than the "true" baseline). The bias is somewhat large (-3.2 to -3.8 percent) for the unadjusted baseline, but is typically less than one percent once a day-of baseline adjustment is applied. The bias is somewhat smaller when examining the event-like days.

Table 5.2: Bias of Alternative Baselines, *PG&E DBP*
(*Median Percentage Error*)

Event Type	Customer Group	# of Cust.-Events	Baseline Adjustment Examined					
			Unadj.	20%	30%	40%	50%	No Cap
All	All	1,658	-3.4%	-0.7%	-0.7%	-0.7%	-0.7%	-0.8%
All	Selected Adj.	1,423	-3.3%	-0.6%	-0.6%	-0.6%	-0.6%	-0.7%
Actual	All	664	-3.8%	-1.1%	-0.9%	-0.9%	-1.0%	-1.0%
Actual	Selected Adj.	429	-3.4%	-1.0%	-0.8%	-0.8%	-0.8%	-0.8%
Event-like	All	994	-3.2%	-0.4%	-0.5%	-0.5%	-0.4%	-0.7%
Event-like	Selected Adj.	994	-3.2%	-0.4%	-0.5%	-0.5%	-0.4%	-0.7%

Table 5.3 provides information about the distribution of percentage baseline errors by customer group. All events (real and simulated) are included in the analysis. The results for all DBP customers (in the top panel) are also shown in Figure 5.1. The values for the 25^{th} and 75^{th} percentiles show the range within which half of the customer-event days fall. For the unadjusted baseline, half of all customer-event days have a baseline error between -11.5 and 3.0 percent. This highlights the negative bias in this baseline calculation.

The distribution is somewhat tighter and less negatively biased when the day-of adjustment is applied. For example, when the 20 percent cap is applied to the day-of adjustment, 50 percent of the customer-event days have a baseline percentage error between -7.2 and +4.9 percent. While the distribution of baseline errors does not vary too much across the different cap levels, the 95^{th} percentile is noticeably worse when the cap is removed.

Figure 5.2 shows the distribution of baseline errors when calculated in levels rather than percentages. That is, the error is calculated as the difference between the simulated baseline and the "true" baseline expressed in kWh. The figure shows that the magnitude of the errors can be quite large, exceeding several hundred kWh. However, viewing the error distribution in this way reduces concerns regarding the effect of using a less restrictive day-of adjustment cap. That is, the error distribution does not appear to change much as one moves from the 20 percent adjustment cap to the uncapped adjustment.

Table 5.3: Percentiles of Percentage Errors of Alternative Baselines, *PG&E DBP*

Customer Group	Count	Percentile	Unadj.	20%	30%	40%	50%	No Cap
All	1,658	5	-47.2%	-39.1%	-42.2%	-45.8%	-51.2%	-99.7%
		10	-25.6%	-21.7%	-24.9%	-25.6%	-26.7%	-36.9%
		25	-11.5%	-7.2%	-7.0%	-7.1%	-7.2%	-7.9%
		Median	-3.4%	-0.7%	-0.7%	-0.7%	-0.7%	-0.8%
		75	3.0%	4.9%	5.3%	5.3%	5.4%	4.8%
		90	30.6%	23.5%	24.8%	23.8%	24.8%	20.5%
		95	90.1%	84.4%	74.8%	67.1%	63.1%	42.3%
Selected Adj.	1,423	5	-38.8%	-33.5%	-34.7%	-42.0%	-48.2%	-89.6%
		10	-23.8%	-20.8%	-22.6%	-23.8%	-24.4%	-29.5%
		25	-11.0%	-6.8%	-7.0%	-7.0%	-7.0%	-7.5%
		Median	-3.3%	-0.6%	-0.6%	-0.6%	-0.6%	-0.7%
		75	2.8%	4.9%	5.4%	5.4%	5.4%	4.9%
		90	27.6%	22.8%	24.1%	23.7%	23.8%	20.1%
		95	87.4%	68.4%	69.5%	62.5%	52.3%	42.3%

Figure 5.1: Percentiles of Relative Errors of Alternative Baseline % Errors, *PG&E DBP*

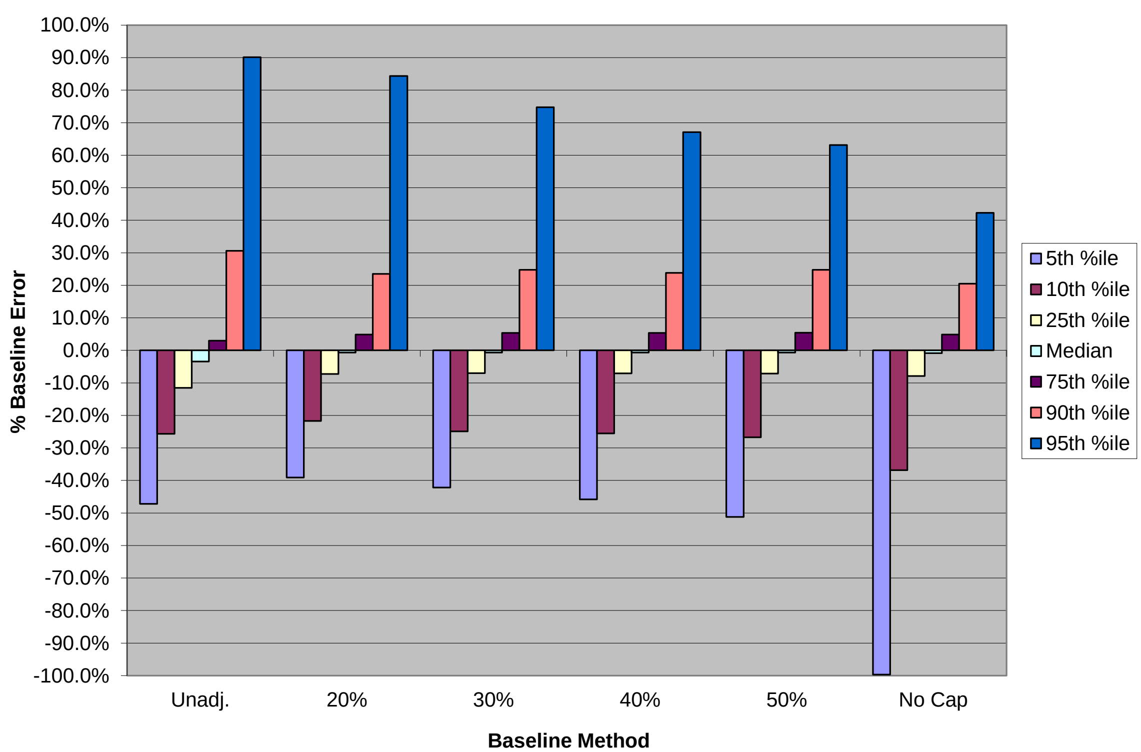
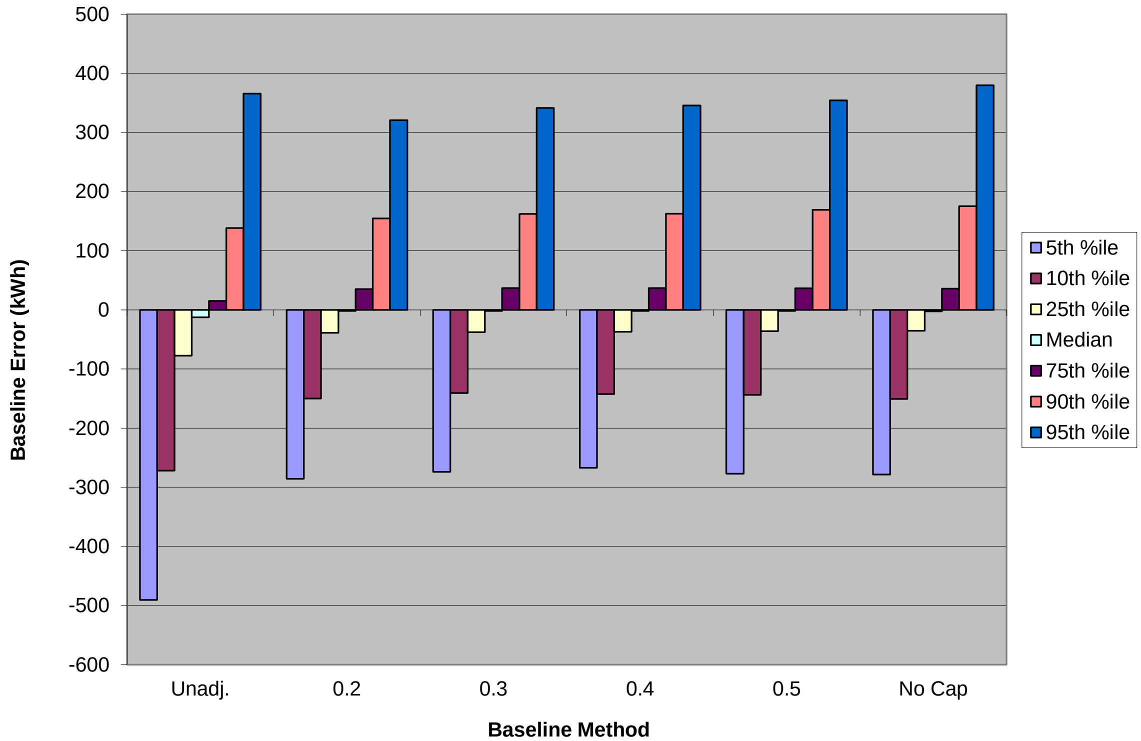


Figure 5.2: Percentiles of Relative Errors of Alternative Baseline kWh Errors, *PG&E DBP*



5.4.2 SCE DBP

Table 5.4 summarizes SCE's the *accuracy* results for the alternative baselines compared to the regression-based and observed baselines, with results reported by customer type (all customers or only those who selected the day-of adjustment) and event type (all studied events, only actual events, and only event-like days).

As with PG&E's baseline study, the adjusted baselines perform better than the unadjusted baselines. The results for SCE are also similar to PG&E's in that the accuracy measures do not vary significantly with the level of the day-of adjustment cap.

Table 5.4: Accuracy of Alternative Baselines, *SCE DBP*
(*Median Absolute Percentage Error*)

Event Type	Customer Group	# of Cust.-Events	Baseline Adjustment Examined					
			Unadj.	20%	30%	40%	50%	No Cap
All	All	5,578	7.8%	5.8%	5.8%	5.9%	5.9%	5.9%
All	Selected Adj.	862	5.7%	4.1%	4.2%	4.3%	4.2%	4.2%
Actual	All	1,867	6.9%	6.0%	6.0%	6.1%	6.1%	6.1%
Actual	Selected Adj.	238	5.2%	4.5%	4.6%	4.6%	4.6%	4.6%
Event-like	All	3,711	8.1%	5.6%	5.7%	5.8%	5.8%	5.8%
Event-like	Selected Adj.	624	5.8%	3.9%	4.1%	4.1%	4.1%	4.1%

Table 5.5 presents results for the typical *bias* of the alternative baselines. The unadjusted baseline has a tendency for baselines to be *understated* (i.e., the calculated

baseline is less than the “true” baseline), while the adjusted baselines tend to be overstated (with some exceptions). The bias tends to be larger (in absolute value) for the unadjusted baselines than it is for the adjusted baselines. For example, the median bias for the unadjusted baseline is -2.4 percent across all customers and events, but only 0.2 to 0.4 percent across the various adjusted baselines.

Table 5.5: Bias of Alternative Baselines, *SCE DBP*
(*Median Percentage Error*)

Event Type	Customer Group	# of Cust.-Events	Baseline Adjustment Examined					
			Unadj.	20%	30%	40%	50%	No Cap
All	All	5,578	-2.4%	0.2%	0.3%	0.4%	0.3%	0.4%
All	Selected Adj.	862	-3.0%	0.4%	0.6%	0.6%	0.7%	0.7%
Actual	All	1,867	-1.9%	1.1%	1.1%	1.2%	1.2%	1.3%
Actual	Selected Adj.	238	-3.0%	2.3%	2.9%	3.0%	3.0%	2.8%
Event-like	All	3,711	-2.6%	-0.2%	-0.1%	0.0%	0.0%	0.0%
Event-like	Selected Adj.	624	-3.1%	-0.2%	-0.1%	0.0%	0.0%	0.0%

Table 5.6 provides information about the distribution of percentage baseline errors by customer group. All events (real and simulated) are included in the analysis. The results for all DBP customers (in the top panel) are also shown in Figure 5.3. For the unadjusted baseline, half of all customer-event days have a baseline error between -9.1 and +5.4 percent. This illustrates that the SCE program baselines are less skewed toward understating the true baseline than those of PG&E.

The distribution of SCE’s baseline results differs from PG&E’s in that the more extreme results do not vary as much as the adjustment cap becomes less restrictive. In short, the results indicate that SCE baseline performance is not substantially affected by the presence of magnitude of the cap on the day-of adjustment (though the presence of a day-of adjustment, regardless of the cap level, produces improved performance relative to the unadjusted baselines).

Table 5.6: Percentiles of Percentage Errors of Alternative Baselines, *SCE DBP*

Customer Group	Count	Percentile	Unadj.	20%	30%	40%	50%	No Cap
All	5,578	5	-29.4%	-25.9%	-28.2%	-29.7%	-30.7%	-32.1%
		10	-18.8%	-15.8%	-16.1%	-16.4%	-16.5%	-16.7%
		25	-9.1%	-5.5%	-5.4%	-5.4%	-5.5%	-5.4%
		Median	-2.4%	0.2%	0.3%	0.4%	0.3%	0.4%
		75	5.4%	6.1%	6.3%	6.5%	6.4%	6.5%
		90	25.8%	18.7%	19.7%	19.8%	19.9%	20.0%
		95	65.7%	51.6%	47.7%	46.1%	45.2%	44.1%
Selected Adj.	**862**	5	-18.8%	-16.1%	-16.5%	-16.5%	-16.5%	-16.8%
		10	-14.1%	-9.8%	-9.8%	-9.8%	-9.6%	-9.6%
		25	-7.8%	-3.5%	-3.4%	-3.4%	-3.2%	-3.1%
		Median	-3.0%	0.4%	0.6%	0.6%	0.7%	0.7%
		75	1.8%	4.4%	4.7%	4.8%	4.8%	4.8%
		90	9.7%	10.6%	12.3%	12.6%	12.9%	13.0%
		95	18.9%	18.4%	19.8%	20.1%	19.9%	20.3%

Figure 5.3: Percentiles of Relative Errors of Alternative Baselines, *SCE DBP*

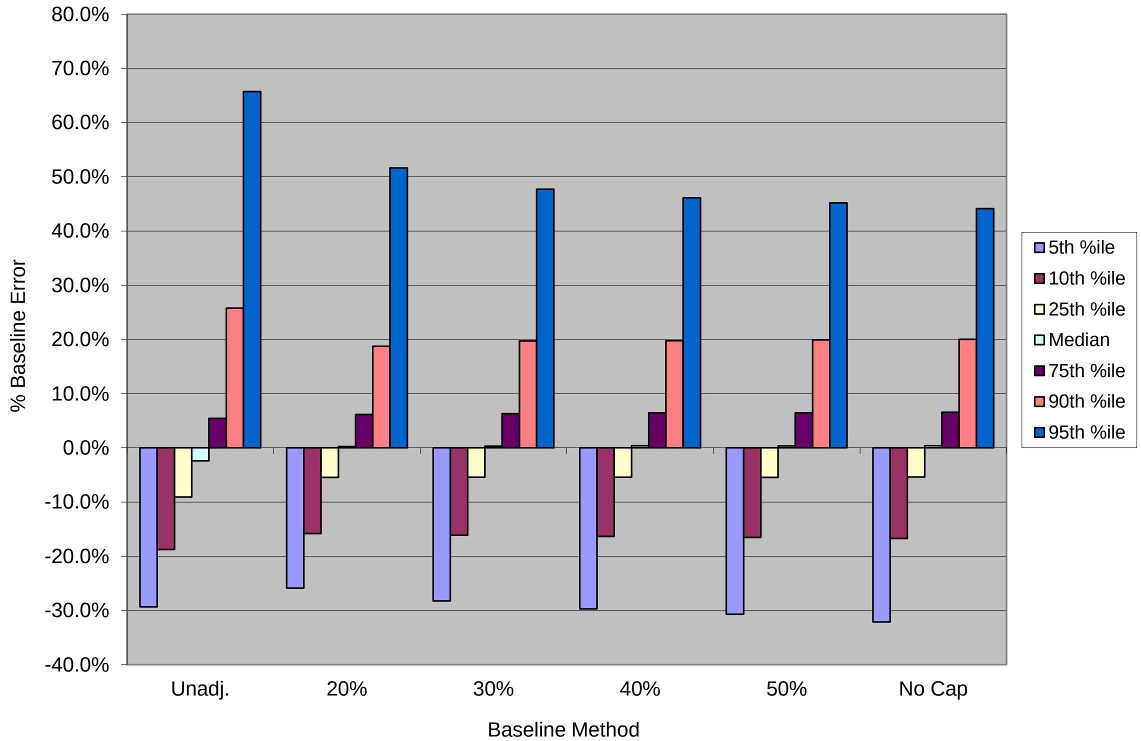
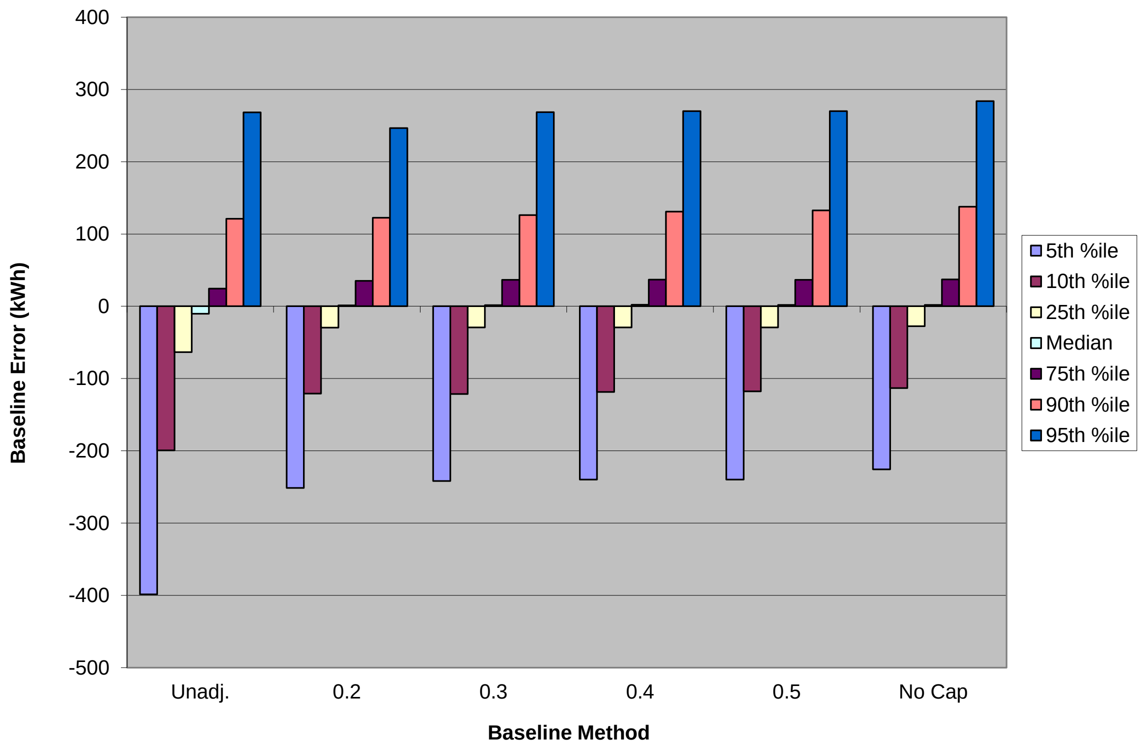


Figure 5.4: Percentiles of Relative Errors of Alternative Baseline kWh Errors, *SCE DBP*



5.4.3 SDG&E DBP

SDG&E only had one customer in each of its Demand Bidding Programs during PY2013, each with multiple service accounts.[20] Accordingly, the baseline study results are summarized in a somewhat different manner than was used for PG&E's and SCE's programs. SDG&E's program uses a different baseline method than SCE and PG&E used. The baseline uses only data from the most recent "similar" non-event day (i.e., a "1-in-1" baseline), where "similar" is based on whether the day is a weekday or weekend day. A day-of adjustment (using the two hours ending two hours before the event begins) with a 40 percent cap was in effect for the sole program participant.

Tables 5.7 through 5.10 summarize the bias and accuracy measures across all event hours on both the actual event days and event-like non-event days (listed in Table 8.2).[21] We examine both the 1-in-1 baseline method used in the program during PY2013 and the 10-in-10 baseline method used in PG&E's and SCE's programs. The baseline study uses customer data in a manner that corresponds with the observed program event days. Specifically, the DBP-DO service accounts are aggregated prior to calculating

[20] The paucity of data (only two customers) limits the extent to which this baseline study should inform baseline policy. At best, the results provide relevant information for the current SDG&E DBP participants.
[21] The event hours are set to hours ending 14 through 17 for the event-like non-event days.

the baseline statistics, while the DBP-DA (Navy) accounts are included as separate entities, with the baseline statistics calculated across all of the account-level results.[22]

Tables 5.7 and 5.8 show the baseline results for the DBP-DO customer. The results show that the bias and accuracy are not sensitive to the day-of adjustment cap level when using the 1-in-1 baseline method. That is, the 40 percent cap produces the same outcomes as the adjustments with 30 and 50 percent caps and the uncapped adjustment. However, overall baseline performance is best when the 10-in-10 baseline with no cap on the day-of adjustment is adopted.

Table 5.7: MPE and MAPE for SDG&E's DBP-DO Baselines

Baseline Method	Day-of Adjustment Cap	Event Days		Event-like Days	
		MPE	MAPE	MPE	MAPE
1-in-1	Unadjusted	-21.4%	21.4%	-21.4%	21.4%
1-in-1	20% Cap	-13.3%	13.3%	-21.4%	21.4%
1-in-1	30% Cap	-10.6%	10.6%	-20.9%	20.9%
1-in-1	40% Cap (current method)	-10.6%	10.6%	-20.9%	20.9%
1-in-1	50% Cap	-10.6%	10.6%	-20.9%	20.9%
1-in-1	Uncapped	-10.6%	10.6%	-20.9%	20.9%
10-in-10	Unadjusted	-34.8%	34.8%	-26.0%	32.6%
10-in-10	20% Cap	-21.7%	21.7%	-20.4%	20.4%
10-in-10	30% Cap	-15.2%	15.2%	-16.0%	16.0%
10-in-10	40% Cap	-8.7%	8.7%	-13.6%	13.6%
10-in-10	50% Cap	-4.9%	8.4%	-11.4%	11.4%
10-in-10	Uncapped	-1.9%	11.5%	-9.7%	9.7%

Table 5.8: Mean Error and Mean Absolute Error for SDG&E's DBP-DO Baselines (kWh)

These results have been removed due to confidentiality concerns.

Tables 5.9 and 5.10 show the baseline results for the DBP-DA (Navy) customer. In this case, the unadjusted 1-in-1 baseline performs the best on the September 6 event day, while the 10-in-10 baseline with an uncapped day-of adjustment performs best on the event-like non-event days.

[22] Unlike the PG&E and SCE analyses, "MPE" and "MAPE" refer to mean results rather than medians.

Table 5.9: MPE and MAPE for SDG&E's DBP-DA Baselines

Baseline Method	Day-of Adjustment Cap	Event Days		Event-like Days	
		MPE	MAPE	MPE	MAPE
1-in-1	Unadjusted	-1.6%	12.3%	8.4%	21.8%
1-in-1	20% Cap	-9.6%	15.3%	7.1%	17.8%
1-in-1	30% Cap	-10.2%	16.0%	6.1%	17.1%
1-in-1	40% Cap (current method)	-10.5%	16.2%	4.8%	16.3%
1-in-1	50% Cap	-10.5%	16.2%	3.5%	15.4%
1-in-1	Uncapped	-10.5%	16.2%	2.8%	12.1%
10-in-10	Unadjusted	39.3%	44.2%	11.5%	34.5%
10-in-10	20% Cap	27.6%	35.8%	14.4%	23.4%
10-in-10	30% Cap	22.3%	30.6%	13.3%	20.5%
10-in-10	40% Cap	17.0%	25.3%	11.3%	17.9%
10-in-10	50% Cap	11.8%	20.1%	9.0%	15.6%
10-in-10	Uncapped	-9.2%	13.6%	2.4%	8.9%

Table 5.10: Mean Error and Mean Absolute Error for SDG&E's DBP-DA Baselines (kWh)

These results have been removed due to confidentiality concerns.

For both DBP-DO and DBP-DA, baseline errors can be quite large. It is difficult to generalize from results based on so few customers, but it appears that the DBP-DO baselines may perform better if a 10-in-10 baseline is used, while the DBP-DA (Navy) baselines contain less evidence that a change in baseline methods would be beneficial.

5.5 Summary of Baseline Analysis

The baseline analysis provides strong evidence that day-of adjustments to the 10-in-10 baseline improve accuracy. However, baseline performance is not as strongly affected by the amount or presence of a cap on the day-of adjustment.

6. Ex Ante Load Impact Forecast

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 conditions, and
- 1-in-10 weather 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 and the relevant LCA. The three size groups were the following:

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

The total number of customer "cells" developed is therefore equal to 24 (= 3 size groups x 8 LCAs).

For SCE, the analysis is complicated by an upcoming change to the program. In 2014, SCE will begin removing "non-performing" customers from DBP. Based on current estimates, approximately 700 service accounts will be removed from DBP for this reason. SCE provided a list of the non-performing service accounts, which we have removed from our ex ante forecasting process beginning in March 2014 (which is the first month in which the lower enrollment level is forecast to occur).

For SDG&E, we assume that the currently enrolled customers continue to participate in DBP, so we do not need to develop customer groups.

6.2.2 Development of Reference Loads and Load Impacts

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

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

Each of these steps is described below.

1. Define data sources

For both PG&E and SCE, the reference loads are developed using data for customers enrolled in DBP during the 2013 program year. The percentage load impacts are developed using the estimated ex post load impacts for the same customers, using data from up to three program years (2011 through 2013). For SDG&E, we use usage data and load impacts from PY2013 only.

For each service account, we determine the appropriate size group, LCA, and dual enrollment status. Service accounts that are dually enrolled in BIP or an aggregator program (e.g., the Capacity Bidding Program) will have their reference loads and load impacts counted in the *program-specific* scenarios (in which each DR program is assumed to be called in isolation), but not in the *portfolio-level* scenarios (in which all DR programs are assumed to have been called).

2. Simulate reference loads

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

For the summer months, the re-estimated regression equations were similar in design to the ex post load impact equations described in Section 3.2, differing in two ways. First, the ex ante models excluded the morning-usage variables. While these variables are useful for improving accuracy in estimating ex post load impacts for particular events, they complicate the use of the equations in ex ante simulation. That is, they would require a separate simulation of the level of the morning load. The second difference between the ex post and ex ante models is that the ex ante models use CDH60 as the weather variables in place of the THI and lagged CDH variables used in the ex post regressions. The primary reason for this is that the historical data used in the ex ante scenarios do not contain complete data on relative humidity, such that we would need to fill in missing data in order to use THI in our simulations. In addition, the ex ante weather days were not selected based on weather from the prior day, restricting the use of lagged weather variables to construct the ex ante scenarios.

Because DBP events may be called in any month of the year, we estimated separate regression models to allow us to simulate non-summer reference loads. The non-summer model is shown below. This model is estimated separately from the summer ex ante model. It only differs from the summer model in three ways: it includes HDH_t variables, where the summer model does not; the month dummies relate to a different set of months; and the event variables are removed (because no event days occurred during the regression timeframe). Table 6.1 describes the terms included in the equation.

$$Q_t = a + \sum_{i=1}^{24}(b_i^{CDH} \times h_{i,t} \times CDH_t) + \sum_{i=1}^{24}(b_i^{HDH} \times h_{i,t} \times HDH_t) + \sum_{i=2}^{24}(b_i^{MON} \times h_{i,t} \times MON_t)$$
$$+ \sum_{i=2}^{24}(b_i^{FRI} \times h_{i,t} \times FRI_t) + \sum_{i=2}^{24}(b_i^{h} \times h_{i,t}) + \sum_{i=2}^{5}(b_i^{DTYPE} \times DTYPE_{i,t})$$
$$+ \sum_{i=2-5,10-12}(b_i^{MONTH} \times MONTH_{i,t}) + e_t$$

Table 6.1: Descriptions of Terms included in the Ex Ante Regression Equation

Variable Name	Variable Description
Q_t	the demand in hour *t* for a customer enrolled in DBP prior to the last event date
The various *b*'s	the estimated parameters
$h_{i,t}$	a dummy variable for hour *i*
CDH_t	cooling degree hours
HDH_t	heating degree hours[23]
MON_t	a dummy variable for Monday
FRI_t	a dummy variable for Friday
$DTYPE_{i,t}$	a series of dummy variables for each day of the week
$MONTH_{i,t}$	a series of dummy variables for each month
e_t	the error term.

Once these models were estimated, we simulated 24-hour load profiles for each required scenario. The typical event day was assumed to occur in August. 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 are the same as those used to develop ex ante load forecasts in the previous two studies (developed following PY2009).

3. Calculate forecast percentage load impacts

For both PG&E and SCE, the percentage load impacts were based on ex post load impact estimates program years 2011 through 2013. Specifically, we examined only customers enrolled in PY2013, but included load impact estimates from the previous two program years for the PY 2013 program participants that also participated in the program in 2011 and 2012. This method allowed us to base the ex ante load impacts on a larger sample of events, which helps improve the reliability and consistency of the load impacts across forecasts.

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

For each service account, we collect the hourly ex post load impact estimates and observed loads for every event available from PY11 through PY13. Within service account, we then calculate the average hourly load impact and observed load profile, as well as the variance of the each hour's load impact across the event days. The average load impacts and their associated variances are converted to percentages by dividing them into the customer's average ex post reference load for the corresponding hour. These percentages are applied to the customer's ex ante (forecast) reference load for each required scenario (e.g., the August peak month day during a 1-in-2 weather year).

From these customer-level forecasts of reference loads and load impacts, we form results for any given sub-group of customers (e.g., customers over 200 kW in size in the Greater Bay Area, who are not dually enrolled in BIP or an aggregator program), by summing the reference loads and load impacts across the relevant customers.

Because the forecast event window (1:00 to 6:00 p.m. in April through October; and 4:00 to 9:00 p.m. in all other months) differs from the historical event window (Noon to 6:00 p.m.), we needed to adjust the historical percentage load impacts for use in the ex ante study. Specifically, in summer months, we adapted the 8-hour historical event window to the 5-hour forecast event window using the correspondence shown in Table 6.2.

Table 6.2: Method of Adapting the Ex Post Event Window to the Ex Ante Window, *PG&E and SCE*

Ex Ante Hour	Ex Post Hour(s)
14	13
15	14, 15
16	16, 17
17	18, 19
18	20

For the non-summer months, the summer hourly percentage load impacts were shifted forward three hours, so that the event hours matched the required 4:00 to 9:00 p.m. window.

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

4. 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.

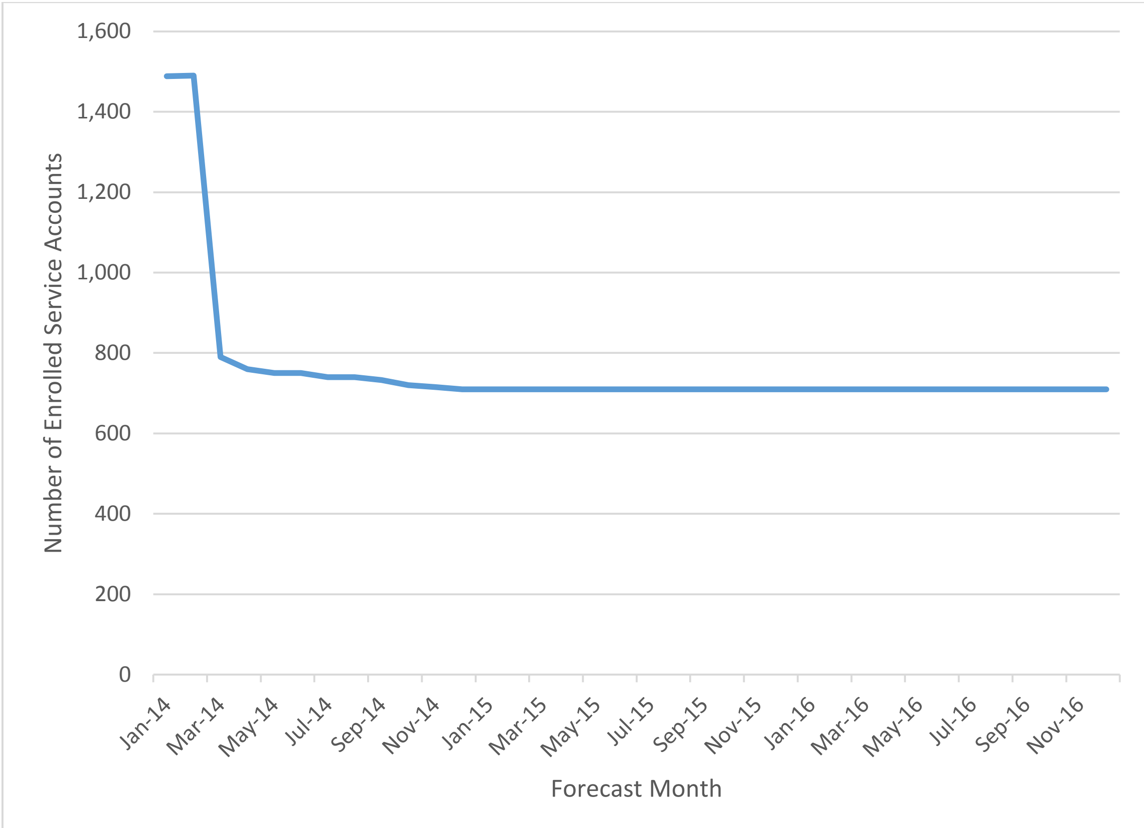
5. Apply forecast enrollments to produce program-level load impacts.
The utilities provided enrollment forecasts. PG&E provided monthly enrollments through 2024, with separate enrollments provided at the program and portfolio level (the latter excludes dually enrolled customers) by LCA and size group. SCE provided monthly enrollments for 2014, 2015, and 2016. We assume that the 2016 enrollments apply through 2024. In addition, SCE provided the list of service accounts that they expect to exclude beginning in 2014 due to non-performance. The enrollments are then used to scale up the reference loads and load impacts for each required scenario and customer subgroup.

6.3 Enrollment Forecasts

PG&E
PG&E forecasts DBP enrollments to remain constant from 2014 through 2024, with 923 service accounts enrolled at the program level. Recall that the portfolio-level analysis excludes customers dually enrolled in DBP and another DR program (e.g., BIP or CBP). Because CBP or AMP are summer-only programs, portfolio-level enrollments vary by season. PG&E forecasts portfolio-level enrollments to be 682 service accounts during the summer months and 822 service accounts during non-summer months.

SCE
Figure 6.1 shows SCE’s forecast of enrollments by month. As described earlier, SCE is planning to remove non-performing customers from the program, which can be seen in the sharp drop in enrollment between February and March 2014. Beginning in March 2014, DBP enrollment declines slightly until December 2014. Enrollment remains at 710 service accounts from that month through the end of the forecast.

Figure 6.1: Number of Enrolled Customers in Each Forecast Month, *SCE*



SDG&E

We assumed that the currently enrolled customers continue to be enrolled in their respective DBP programs.

6.4 Reference Loads and Load Impacts

For each utility and program type, we provide the following summary information: 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 2015 forecast load impacts for a typical event day in a 1-in-2 weather year. Event-hour (1:00 to 6:00 p.m.) load impacts average 42.5 MW, which represents 5.0 percent of the enrolled reference load. Figure 6.3 shows the same load impacts at the portfolio level (i.e., when all DR programs are simultaneously called). On average, the load impacts are reduced by 39.3 MW (relative to the program-level load impact) to 3.2 MW and the percentage load impact goes down to 0.6 percent. The large difference between program and portfolio load impacts is due to the contribution of customers dually enrolled in DBP and BIP or an aggregator program. In the portfolio analysis (when BIP and aggregator events are assumed to be called at the same time as the DBP event), the load impacts for the dually enrolled customers are removed from DBP, dramatically reducing the load impact.

Figure 6.2: PG&E Hourly Event Day Load Impacts for the Typical Event Day in a 1-in-2 Weather Year for August 2015, Program Level

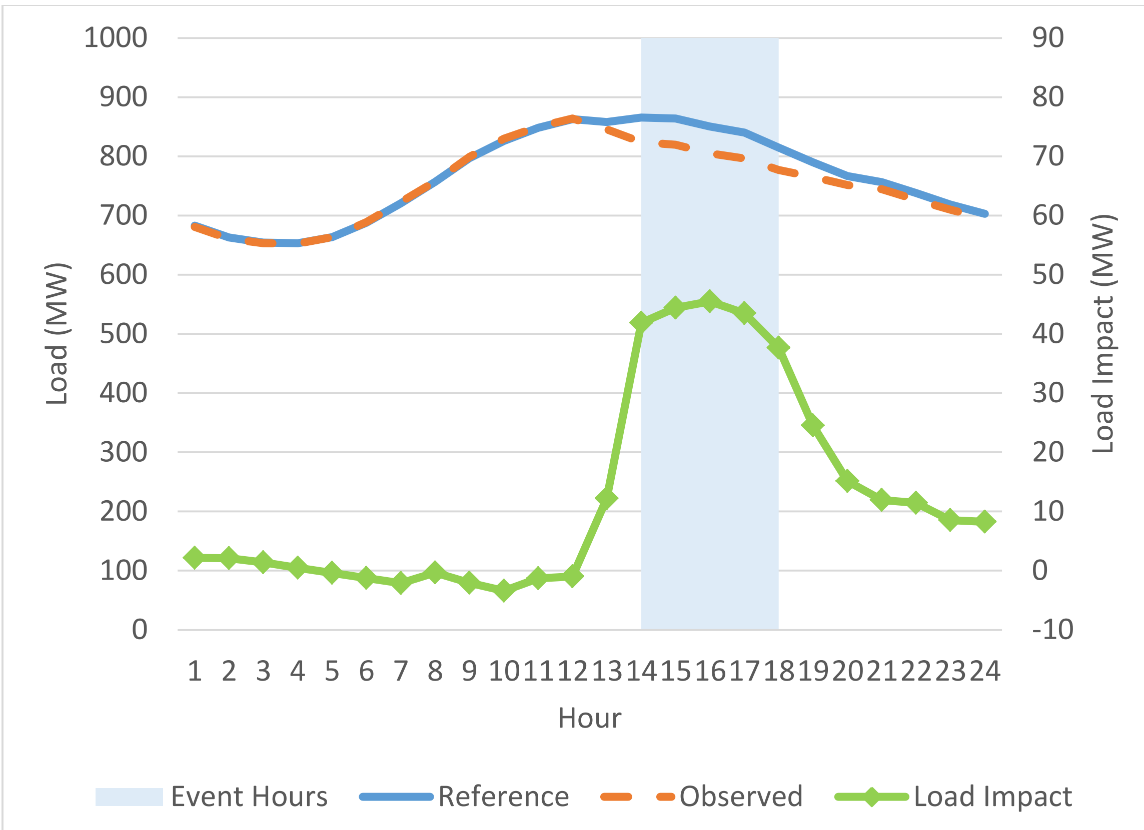


Figure 6.3: PG&E Hourly Event Day Load Impacts for the Typical Event Day in a 1-in-2 Weather Year for August 2015, Portfolio Level

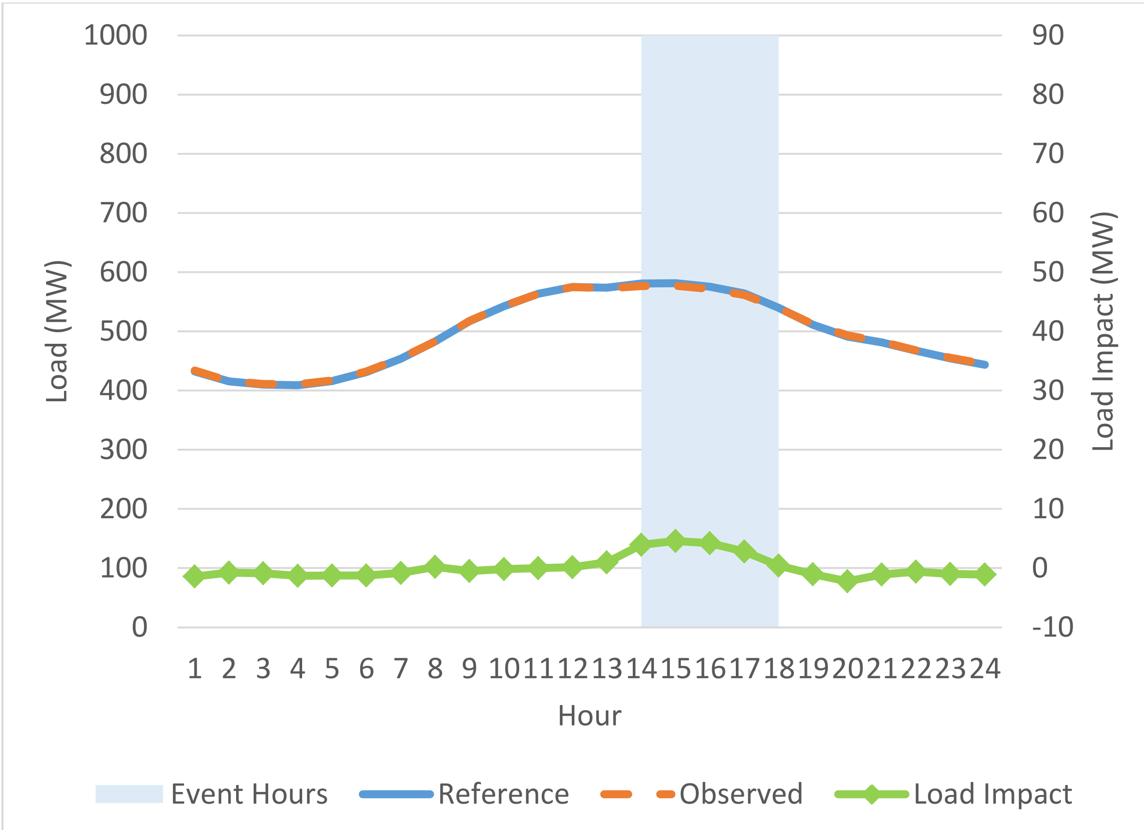


Figure 6.4 shows the share of load impacts by local capacity area, assuming a typical event day in an August 2015 1-in-2 weather year. Customers not in any LCA account for the largest share, with 84 percent of the load impacts.

Figure 6.4: Share of PG&E Load Impacts by LCA for the August 2015 Typical Event Day in a 1-in-2 Weather Year

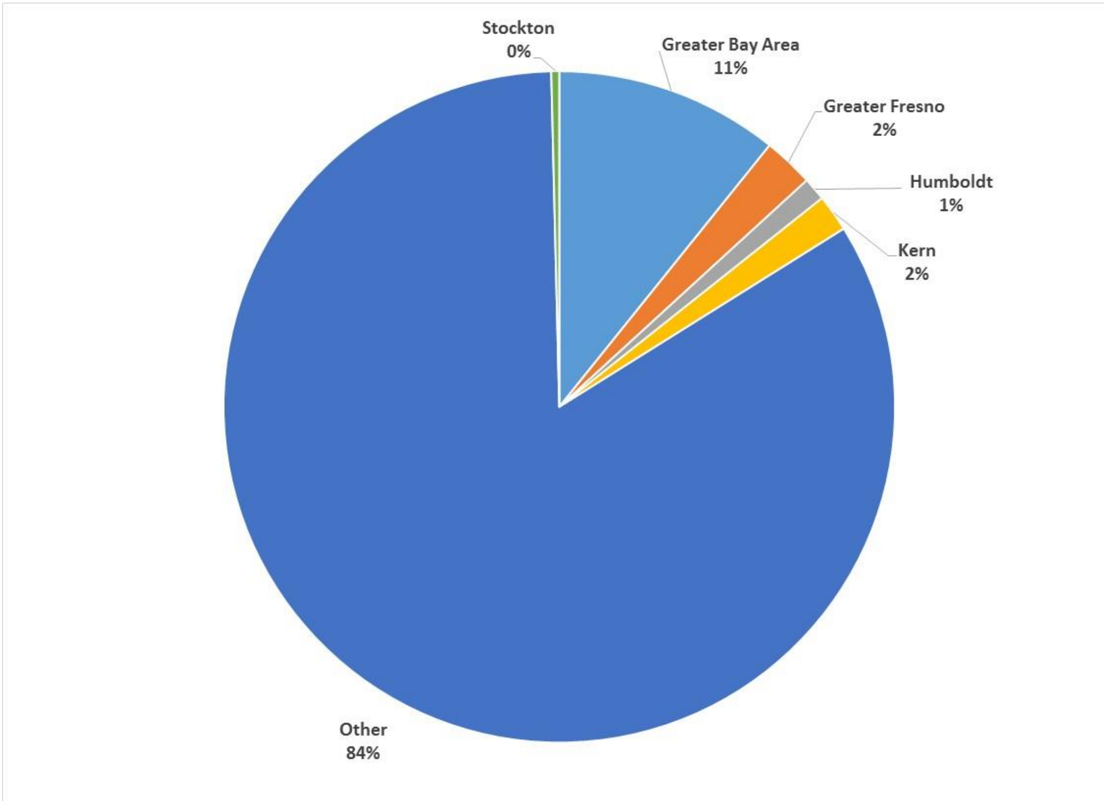


Figure 6.5 illustrates August load impact for each forecast scenario, differentiated by 1-in-2 versus 1-in-10 weather conditions, and portfolio- versus program-level load impacts. Recall that the enrollment forecast does not change across the 2014-2014 window, so these load impacts apply stay consistent for August across the forecast years. There is a very small difference in load impacts across weather scenarios, but the portfolio-level load impacts are much lower than the program-level load impacts (due to the removal of the customers dually enrolled in BIP or an aggregator program).

Figure 6.5: Average Hourly Ex Ante Load Impacts by Scenario for August, *PG&E*

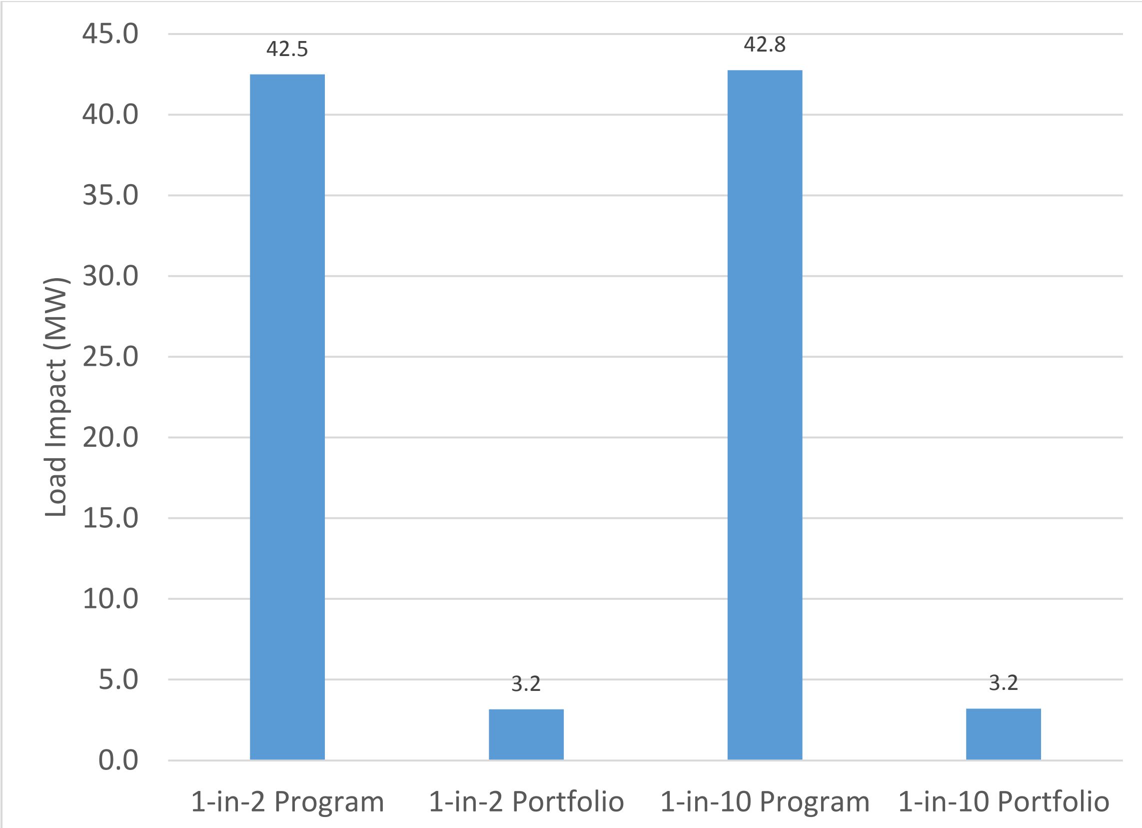


Table 6.3 shows the per-customer reference loads and load impacts by weather year and event-day scenario (program- versus portfolio-based) for the August monthly peak day.

Table 6.3: Per-customer Ex Ante Load Impacts, *PG&E*

Scenario	Weather Year	Reference Load (kW)	Load Impact (kW)	% Load Impact
Program-based	1-in-2	922.6	46.0	5.0%
	1-in-10	925.5	46.3	5.0%
Portfolio-based	1-in-2	839.3	4.6	0.6%
	1-in-10	842.7	4.7	0.6%

6.4.2 SCE

Figure 6.6 shows the program-level forecast reference loads and load impacts for the August 2015 peak day in a 1-in-2 weather year. The average program-level load impact is 93.6 MW, or 13.4 percent of the reference load.

Figure 6.7 shows the portfolio-level forecast for the August 2015 peak day in a 1-in-2 weather year. This forecast differs from the program-level forecast by excluding customers who are dually enrolled in DBP and BIP or AMP/DRC. Because the dually enrolled customers are much more demand responsive than the DBP-only customers, the load impacts are much lower in the portfolio-based scenario. Event-hour load impacts average 4.9 MW (a reduction of 88.7 MW relative to the program-level load impacts), or 1.3 percent of reference load.

Figure 6.6: SCE Hourly Event Day Load Impacts for the Typical Event Day in a 1-in-2 Weather Year for August 2015, Program Level

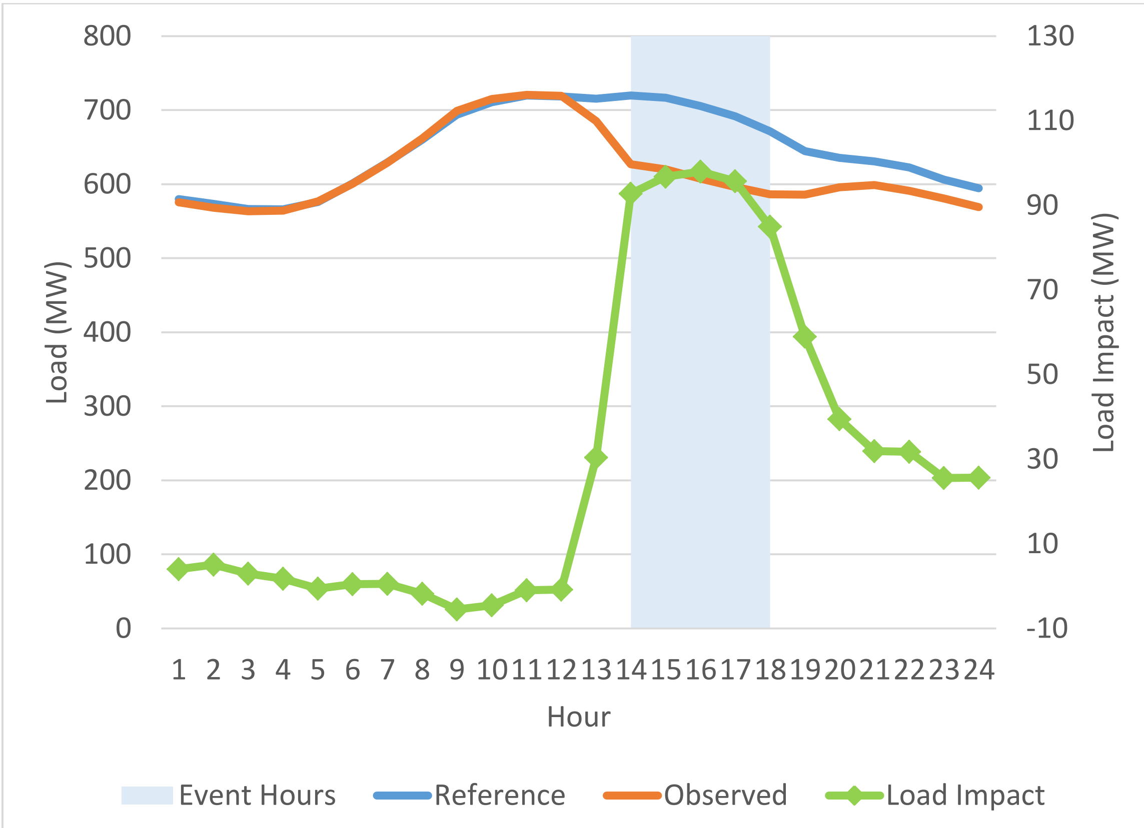


Figure 6.7: SCE Hourly Event Day Load Impacts for the Typical Event Day in a 1-in-2 Weather Year for August 2015, Portfolio Level

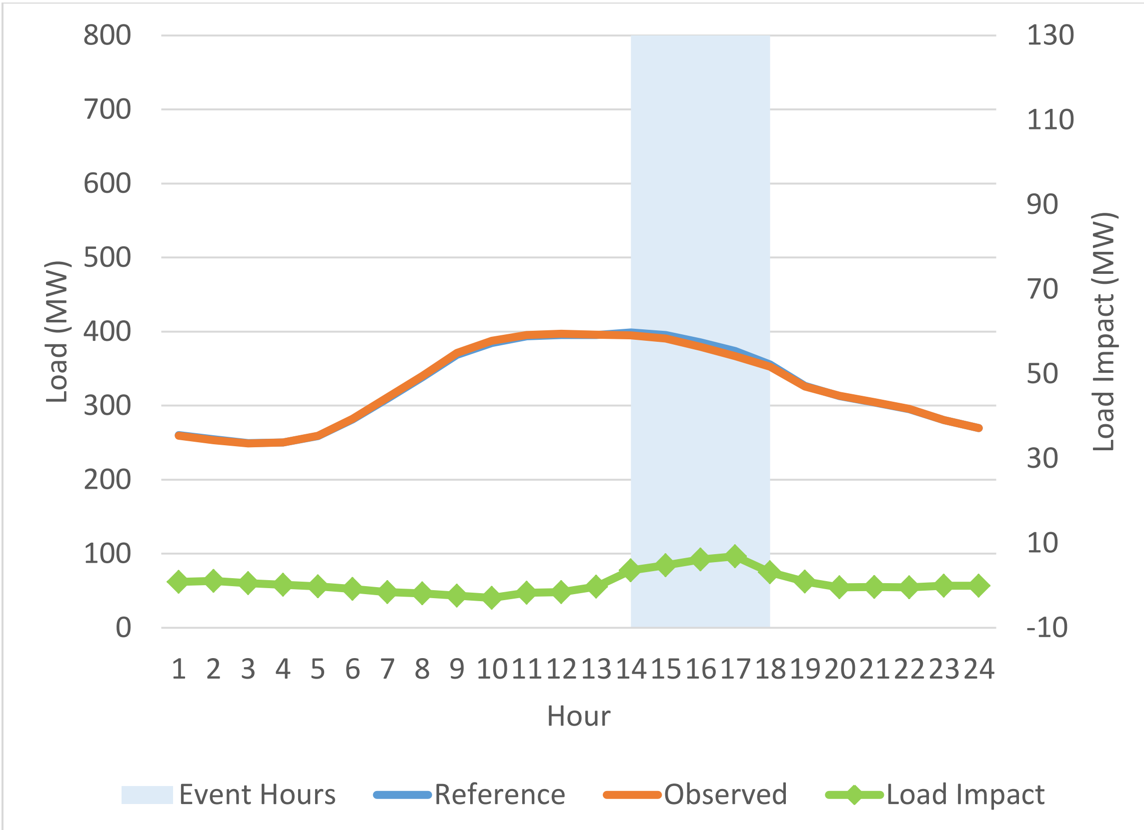


Figure 6.8 shows the distribution of 1-in-2 August 2015 program-level load impacts across local capacity areas. The LA Basin accounts for the largest share, with 60 percent of the total load impacts.

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

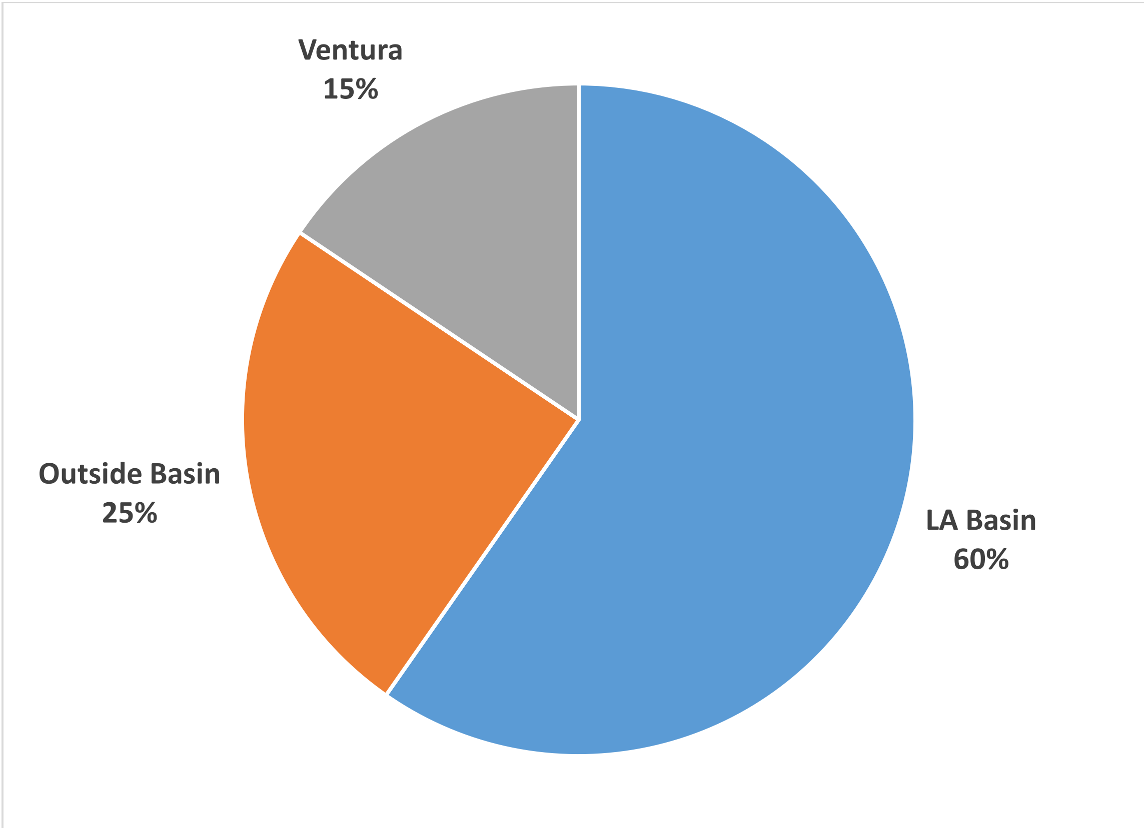


Figure 6.9 illustrates the average August hourly load impact across scenarios and year. The load impacts in 1-in-10 weather years are virtually identical to the corresponding 1-in-2 load impacts, but the program-level load impacts are much higher than the portfolio-level load impacts. By 2016, the program-level load impact is 93.6 MW in the 1-in-2 weather year.

Figure 6.9: Average Hourly Ex Ante Load Impacts by Scenario and Year, *SCE*

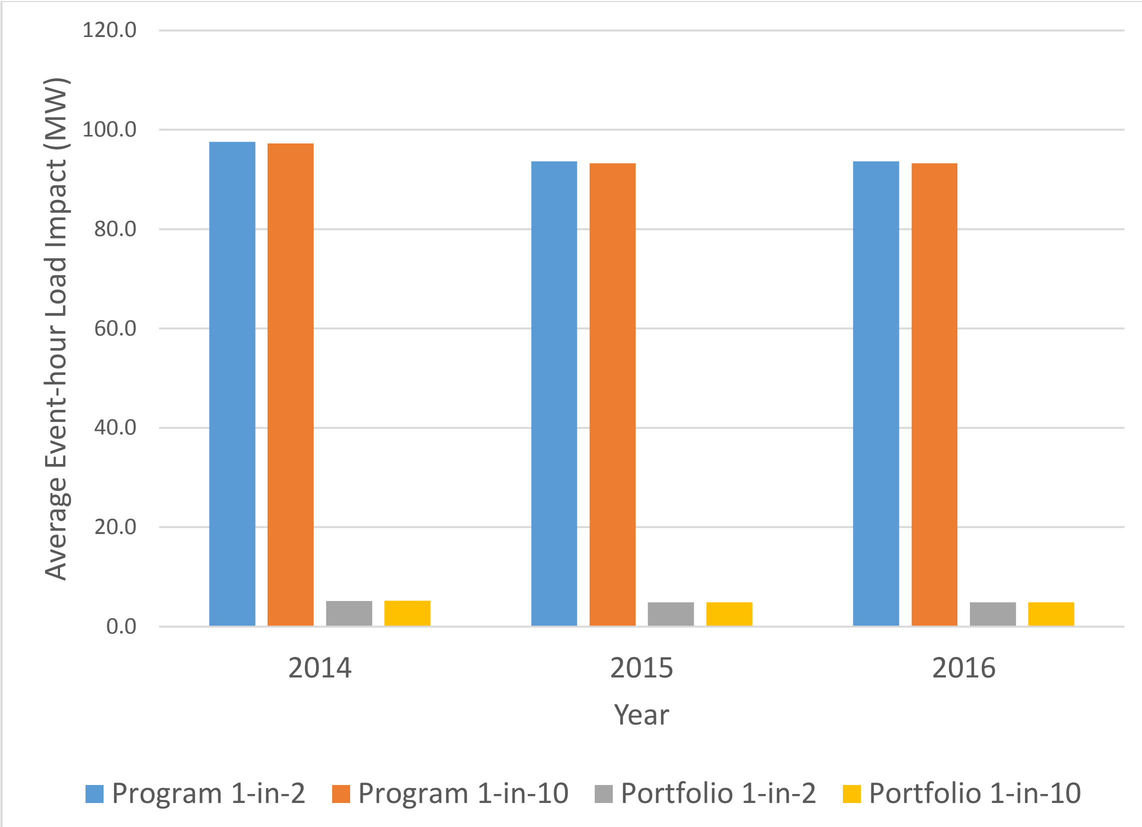


Table 6.4 shows the per-customer reference loads and load impacts by weather year and event-day scenario (program- versus portfolio-based) for the August 2014 monthly peak day.

Table 6.4: Per-customer Ex Ante Load Impacts, *SCE*

Scenario	Weather Year	Reference Load (kW)	Load Impact (kW)	% Load Impact
Program-based	1-in-2	987	131.9	13.4%
	1-in-10	997	131.4	13.2%
Portfolio-based	1-in-2	683	8.7	1.3%
	1-in-10	694	8.8	1.3%

6.4.3 SDG&E

SDG&E is forecasting that enrollment in its two DBP programs will continue at current levels for the entire forecast period. Because enrollments do not vary across years and SDG&E consists of only one LCA, fewer results are presented for SDG&E than for PG&E and SCE.

Figures 6.10 and 6.11 show the September 2014 1-in-2 ex ante hourly reference loads, observed loads, and load impacts for the DBP-DA (Navy) and DBP-DO programs, respectively.

Figure 6.10: SDG&E DBP-DA Hourly Event Day Load Impacts for the Typical Event Day in a 1-in-2 Weather Year for September 2014

These results have been removed due to confidentiality concerns.

Figure 6.11: SDG&E DBP-DO Hourly Event Day Load Impacts for the Typical Event Day in a 1-in-2 Weather Year for September 2014

These results have been removed due to confidentiality concerns.

Table 6.5 shows the monthly forecast of monthly load impacts for each of SDG&E's Demand Bidding Programs. Because enrollments are forecast to remain the same during the ex ante forecast timeframe, these results apply to each of 2014 through 2024.

For the DBP-DO program, the level of the load impact is quite variable across months. Because the level of the load impact is a fixed percentage derived from the ex post load impacts, the variation in level of load impacts is due to variation in the size of the reference load. For example, the average event-hour reference load for the September 1-in-2 peak day is 2.8 MW higher than the corresponding load during the August 1-in-2 peak day.

Table 6.5: Forecast Monthly Load Impacts, *SDG&E DBP-DA and DBP-DO*

Month	DBP-DA	DBP-DO
January	5.0	1.1
February	3.1	1.4
March	3.7	0.8
April	6.1	2.8
May	5.2	2.1
June	6.1	1.8
July	5.9	2.8
August	6.0	2.8
September	5.8	3.8
October	5.6	3.0
November	5.5	2.8
December	5.0	1.2

7. Comparisons of Results

In this section, we present several comparisons of load impacts for each utility:

- Ex post load impacts from the current and previous studies;
- Ex ante load impacts from the current and previous studies;
- Previous ex ante and current ex post load impacts; and

- Current ex post and ex ante load impacts.

In the above "current study" refers to this report, which is based on findings from the PY2013 program year; and "previous study" refers to the report that was developed following the PY2012 program year.

7.1 PG&E

7.1.1 Previous versus current ex post

Table 7.1 shows the average event-hour reference loads and load impacts for the three previous program years. Note that the three "partial" events that were called in PY2013 (during which only a sub-set of PG&E's service territory were called) are excluded from the calculations. In addition, PY2011 differs from PY2012 and PY2013 in that the event window was hours-ending 15 through 18, whereas the event window was hours-ending 13 through 20 for the following two program years.[24]

Table 7.1: Comparison of Average Event-day Ex Post Impacts (in MW) in PY 2011 through PY 2013, *PG&E*

Level	Outcome	PY2011	PY2012	PY2013
Total	# SAIDs	1,039	998	952
	Reference (MW)	818	817	826
	Load Impact (MW)	57	38	36
Per SAID	Reference (kW)	787	819	867
	Load Impact (kW)	55	38	38
	% Load Impact	7.0%	4.6%	4.3%

The ex post load impacts were quite similar for PY2012 and PY2013, though both were lower than we estimated for PY2011. As we noted in the PY2012 DBP study, the majority of the difference in load impacts between PY2011 and PY2012 is due to the fact that a large responder in PY2011 did not submit any bids in PY2012. This alone accounts for approximately 11 MW of the difference between years. Variability in event-to-event and year-to-year load impacts is affected by the fact that relatively few SAIDs account for the vast majority of the program load impact. For example, in PY 2013 five SAIDs accounted for more than 80 percent of the total program load impact on the average event day.

7.1.2 Previous versus current ex ante

In this sub-section, we compare the ex ante forecast prepared following PY 2012 (the "previous study") to the ex ante forecast contained in this study (the "current study").

[24] Calculating the PY2012 and PY2013 averages over hours-ending 15 through 18 does not substantially change the results.

Table 7.2 contains this comparison for the August 2014 1-in-2 peak month day forecast. Both the program-level and portfolio-level load impacts are presented. Note that the portfolio-level load impacts (which exclude dually enrolled customers) are much lower than the program-level load impacts in both forecasts.

Table 7.2: Comparison of Ex Ante Impacts from PY 2012 and PY 2013 Studies, *PG&E*

Level	Outcome	Program Level		Portfolio Level	
		Previous Study 2014	Current Study 2014	Previous Study 2014	Current Study 2014
Total	# SAIDs	1,047	923	787	682
	Reference (MW)	913.8	851.5	617.3	572.4
	Load Impact (MW)	54.3	42.5	2.8	3.2
Per SAID	Reference (kW)	873	923	785	839
	Load Impact (kW)	52	46	4	5
	% Load Impact	5.9%	5.0%	0.4%	0.6%

The table shows a larger reduction in enrollments than in reference loads, which increases the average customer size across forecasts. As Table 7.1 shows, the increase in average customer size is consistent with our findings from recent ex post studies. The program-level percentage load impact decreases from 5.9 percent to 5.0 percent across years, which drives are reduction in total load impacts from 54.3 to 42.5 MW. Recall that the ex ante forecast uses ex post load impact estimates from the three previous evaluations. In this evaluation, we used PY2011 through PY2013, whereas the previous evaluation used PY2010 through PY2012. Therefore, a change from last year's forecast to this year's forecast is that PY2010 load impacts were replaced with PY2013 load impacts. Because PY2013 load impacts tended to be lower (in percentage terms) than PY2010 load impacts, this reduces the overall ex ante percentage load impact.

7.1.3 Previous ex ante versus current ex post

Table 7.3 provides a comparison of the ex ante forecast of 2013 load impacts prepared following PY2013 and the PY2013 load impacts estimated as part of this study. The ex ante forecast shown in the table represents the typical event day during a 1-in-2 weather year. The ex post load impacts are averaged across the three PY2013 event days during which all DBP customers were given the opportunity to bid (July 1, July 3, and September 9).

The forecast included somewhat more customers than were enrolled during PY2013 (1,015 versus 952), but the difference is not large enough to account for the substantial difference in load impacts. The forecast called for an average load impact of 53 MW, whereas we estimated an average load impact of 36 MW during PY2013.

Table 7.3 Comparison of Previous Ex Ante and Current Ex Post Impacts, *PG&E*

Level	Outcome	Ex Ante for TED in PY2013, following PY2012 Study	Ex Post Average Event Day, PY2013
Total	# SAIDs	1,015	952
	Reference (MW)	882	826
	Load Impact (MW)	53	36
Per SAID	Reference (kW)	869	867
	Load Impact (kW)	52	38
	% Load Impact	6.0%	4.3%

Our exploration of the underlying (SAID-level) data found two sources for the difference. First, when comparing the forecast and estimated load impacts of individual SAIDs, we found that the forecast had a tendency to over-forecast load impacts (though many SAIDs were under-forecast as well). This may be due to the inclusion of PY2011 ex post load impacts in the development of the ex ante forecast. The load impacts from PY2011 tended to be higher than in subsequent years, which could be due to random variation in customer performance (or at least random from our perspective) or due to the shorter (4-hour) event window during that program year.

The second major source of the difference between ex post and ex ante load impacts is a difference in the forecast versus observed enrollments. Specifically, the enrollment forecast for 2013 produced following PY2012 included a higher proportion of demand responsive customers (i.e., relatively more customers in larger size groups and LCAs that have historically been more responsive on average).

These two effects each account for approximately half of the difference between the ex ante and ex post load impacts shown in Table 7.3.

7.1.4 Current ex post versus current ex ante

The 2014 ex ante load impact forecast is somewhat higher than the PY 2013 ex post load impacts in both level and percentage terms. Table 7.4 describes the sources of differences between PY 2013 ex post and ex ante load impacts for the 2014 1-in-2 August peak day. The key points of the table can be summarized as follows:

- Weather conditions are an average of 4.2 degrees Fahrenheit hotter during the ex ante event hours compared to the corresponding hours of the average ex post event day (hours ending 14 through 18). This will increase the overall reference load. The effect on load impacts is smaller because percentage load impacts do not change with weather conditions.[25]

[25] We estimated a statistical model of percentage load impacts at the customer/event-day level using PY 2011- PY 2013 data. We controlled for day type and the different event window used in PY 2011 and

- While the ex post and ex ante event windows differ, we force the ex ante model to reflect the load impacts observed during the historical event window. Table 6.3 shows how we map the ex post event hours into the ex ante event hours. Therefore, the difference in event windows should have a negligible effect on the forecast.

- The percentage of the program dispatched does not affect the ex ante forecast because the ex ante forecast assumes that all enrolled customers are called. In addition, when we compare ex post and ex ante load impacts, we exclude the "partial" event days from the ex post load impact summaries.

- The enrollment forecast calls for a drop in the number of SAIDs, but the number of large (over 200 kW) SAIDs remains approximately constant. This has the effect of decreasing the total program reference load and load impact drops, but at the same time *increasing* the per-customer reference load and load impacts.

- Finally, our methodology uses up three years of load impacts for SAIDs that were enrolled in PY 2013 and either PY 2012 or PY 2011. Because percentage load impacts were higher in PY 2011, this increases the ex ante forecast relative to PY 2013 ex post load impacts.

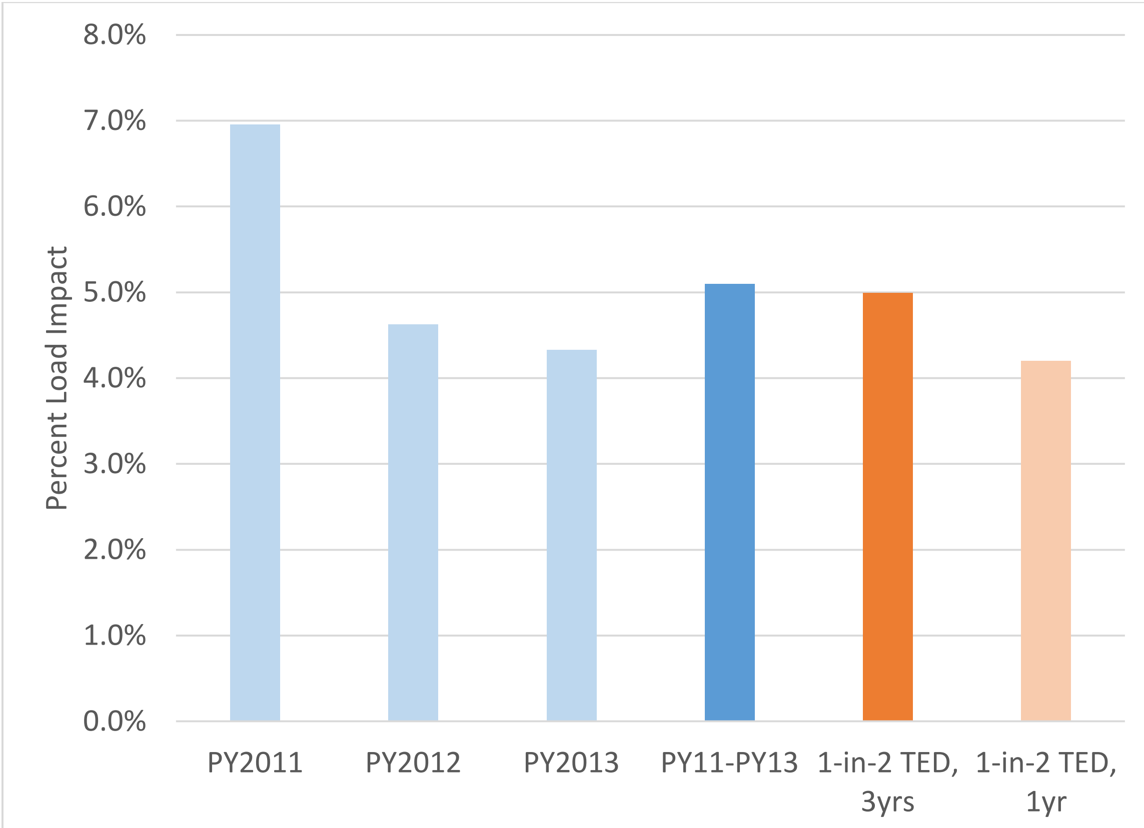
found no statistically significant relationship between event-hour temperatures and percentage load impacts.

Table 7.4: PG&E Ex Post versus Ex Ante Factors

Factor	Ex Post	Ex Ante	Expected Impact
Weather	89.3 degrees Fahrenheit during event hours.	93.5 degrees Fahrenheit during event hours on 1-in-2 Aug peak day.	Hotter ex ante weather increases the reference load somewhat but has a smaller effect on load impacts since the %LI does not vary with weather.
Event window	HE 13-20.	HE 14-18 in Apr-Oct; HE 17-21 in Nov-Mar.	Minimal in summer; non-summer load impacts are speculative as we have not observed events in those months.
% of resource dispatched	3 events with full dispatch; 3 with partial dispatch.	Assume all customers are called.	None. The ex ante method assumes that all enrolled customers are dispatched.
Enrollment	952 SAIDs during the average event day.	923 SAIDs.	Reduction in enrollment level reduces reference loads and load impacts, but mitigated by the fact that the number of over-200kW customers remains about the same.
Methodology	SAID-specific regressions using own within-subject analysis.	Reference loads are simulated from SAID-specific regressions. Load impacts are based on (up to) 3-years of SAID-specific load impacts.	Use of 3 years of load impacts tends to increase load impacts relative to current-year ex post estimates because PY11 had higher %LI.

Figure 7.1 illustrates the effect of using three years of load impacts to develop the ex ante forecast, instead of using only the most recent year. Moving from left to right, the light blue bars show the average percentage load impact for each of the program years included in the development of the ex ante forecast. The dark blue bar is the average across the event days in the three program years. The dark orange bar is the average percentage load impact from the 2014 August 1-in-2 peak day. Notice that this percentage (5.0 percent) is somewhat higher than the PY 2013 percentage load impact of 4.3 percent, but very close to the three-year average (the dark blue bar) of 5.1 percent. The light orange bar on the far right shows the ex ante forecast that results from using only the PY 2013 load impacts, which is 4.2 percent. This essentially matches the PY2013 ex post percentage load impact of 4.3 percent. This demonstrates that the higher ex ante percentage load impact is almost entirely due to the use of 3 years of ex post load impacts versus using only the most recent program year.

Figure 7.1: Percentage Load Impacts by Program Year and Ex Ante Forecast Method



7.2 SCE

7.2.1 Previous versus current ex post

Table 7.5 compares ex post load impacts for the typical event day across the three most recent program years. Despite having slightly fewer customers and a lower overall reference load, PY2013 had the largest load impact in both level and percentage terms.

Table 7.5 Comparison of Average Event-day Ex Post Impacts (in MW) in PY 2011 through PY 2013, *SCE*

Level	Outcome	PY2011	PY2012	PY2013
Total	# SAIDs	1,354	1,369	1,312
	Reference (MW)	1,024	1,027	994
	Load Impact (MW)	78	83	99
Per SAID	Reference (kW)	756	751	758
	Load Impact (kW)	57	60	76
	% Load Impact	7.6%	8.1%	10.0%

7.2.2 Previous versus current ex ante

In this sub-section, we compare the ex ante forecast prepared following PY 2012 (the "previous study") to the ex ante forecast contained in this study (the "current study"). Table 7.6 represents the forecast for the August 2014 1-in-2 peak month day. Both program-level and portfolio-level forecasts are included in the table.

Table 7.6: Comparison of Ex Ante Impacts from PY 2012 and PY 2013 Studies, *SCE*

Level	Outcome	Program Level		Portfolio Level	
		Previous Study 2014	Current Study 2014	Previous Study 2014	Current Study 2014
Total	# SAIDs	1,022	740	635	589
	Reference (MW)	958	731	465	402
	Load Impact (MW)	82	98	4	5
Per SAID	Reference (kW)	937	987	733	683
	Load Impact (kW)	80	132	7	9
	% Load Impact	8.6%	13.4%	1.0%	1.3%

Notice that the forecast enrollment dropped significantly across the two years. This is primarily due to an increase in the number of service accounts that are assumed to be removed for non-performance. Stronger overall response from the remaining customers causes the total and percentage load impact to increase relative to last year's forecast despite the reduced number of customers.

7.2.3 Previous ex ante versus current ex post

Table 7.7 provides a comparison of the ex ante forecast of 2013 load impacts prepared following PY2013 and the PY2013 load impacts estimated as part of this study. The ex ante forecast shown in the table represents the typical event day during a 1-in-2 weather year. The ex post load impacts are averaged across the five PY2013 event days.

Notice that the ex ante forecast assumed fewer customers than were enrolled during PY2013, but the forecast customers were larger on average. The total ex post load impact was higher in level and percentage terms than the ex ante load impacts.

Table 7.7 Comparison of Previous Ex Ante and Current Ex Post Impacts, *SCE*

Level	Outcome	Ex Ante for TED in PY2013, following PY2012 Study	Ex Post Average Event Day, PY2013
Total	# SAIDs	1,022	1,312
	Reference (MW)	948	994
	Load Impact (MW)	82	99
Per SAID	Reference (kW)	928	758
	Load Impact (kW)	80	76
	% Load Impact	8.7%	10.0%

Table 7.8 compares the bid realization rates from PY2011 through PY2013. The total bid load reduction was very similar between PY2012 and PY2013 (and was not much lower in PY2011), but the bid realization rate (the load impact divided by the bid amount) was quite a bit higher in PY2013 than it was in the two prior program years. We do not know what motivated this change in customer behavior, but it appears to be the most important factor in explaining the difference between the ex ante and ex post load impacts.

Table 7.8 Comparison of Bid Realization Rates from PY2011 to PY2013, *SCE*

Outcome	PY2011	PY2012	PY2013
Avg. Bid Amount	129.1	134.3	134.2
Avg. Load Impact	77.7	82.8	99.5
Realization Rate	60%	61.7%	74.1%

7.2.4 Current ex post versus current ex ante

Table 7.9 describes the sources of differences between the ex post and ex ante load impacts, using the August 2014 1-in-2 scenario as the benchmark for comparison. The key points of the table can be summarized as follows:

- Ex ante weather conditions are hotter than the observed weather conditions on the PY2013 event days, but this does not have a large effect on the estimated load impacts. Our analysis of ex post load impacts from PY2011 through PY2013 indicated that percentage load impacts do not vary with temperature, so we apply the same percentage load impacts to the various weather-based scenarios.

- The ex post event window is longer than the event window used in the ex ante forecast. This does not affect the percentage load impacts, as we map the ex post event window into the ex ante event window (see Table 6.2 for the method used).

- All enrolled service accounts are invited to bid in both ex post and ex ante events, so program dispatch does not produce differences between the two sets of load impacts.

- The enrollment forecast does produce some differences between the ex post and ex ante load impacts. Specifically, the ex ante load impact forecast assumes that approximately 700 service accounts are removed from DBP for non-performance. The number of "retained" service accounts from our ex post analysis is somewhat lower than the ex ante enrollment forecast, which implies that the number of responsive service accounts is expected to increase somewhat in 2014 through 2016. The combined effect of these enrollment changes is to reduce the overall reference load, but increase the level of the load impact (since the removed customers did not respond and new responsive customers are assumed to join the program). As a result, the ex ante percentage load impacts are substantially higher than the ex post load impacts.

- The use of three years of load impacts (PY2011 through PY2013, using previous program-year results only for customers enrolled during PY2013) tends to decrease load impacts relative to what we would have forecast using only PY2013 load impacts. This is because percentage load impacts were higher during PY2013 than the previous two program years.

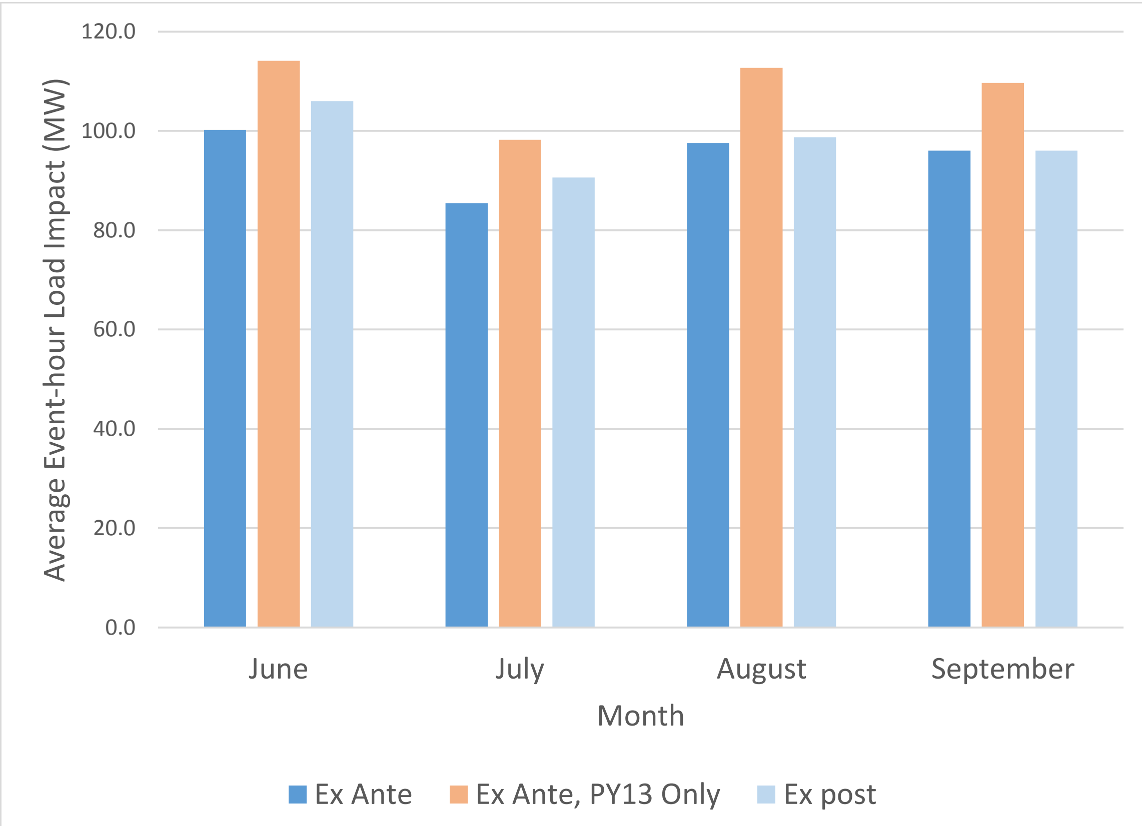
Table 7.9: SCE Ex Post versus Ex Ante Factors

Factor	Ex Post	Ex Ante	Expected Impact
Weather	83.9 degrees Fahrenheit during event hours.	91.9 degrees Fahrenheit during event hours on 1-in-2 Aug peak day.	Hotter ex ante weather increases the reference load somewhat but has a smaller effect on load impacts since the %LI does not vary with weather.
Event window	HE 13-20.	HE 14-18 in Apr-Oct; HE 17-21 in Nov-Mar.	Minimal in summer; non-summer load impacts are speculative as we have not observed events in those months.
% of resource dispatched	All customers were called.	Assume all customers are called.	None. The ex ante method assumes that all enrolled customers are dispatched.
Enrollment	1,312 SAIDs during the average event day.	740 SAIDs in August 2014.	Removal of non-performing customers reduces enrollment. There is a forecast increase in the number of performing customers. The net effect is to increase average customer size, the percentage load impact, and the total load impact.
Methodology	SAID-specific regressions using own within-subject analysis.	Reference loads are simulated from SAID-specific regressions. Load impacts are based on (up to) 3-years of SAID-specific load impacts.	Use of 3 years of load impacts decreases percentage load impacts relative to current-year ex post estimates because PY13 had higher %LI than PY11 and PY12.

Figure 7.2 illustrates the consistency of the ex post and ex ante load impacts and shows the effect of using three years of ex post load impacts versus results from only PY2013. The figure shows results by month, from June through September. Each month contains three results. The dark blue bar on the left shows the average event-hour load impact for the 2014 1-in-2 weather year, developed using the methods described in Section 6. The light orange bar in the middle shows how this ex ante forecast would change if we used only PY2013 ex post load impacts (as opposed to PY2011 through PY2013). The light blue bar on the right shows the average event-hour load impacts for the PY2013 event days that occurred in each month.

It tends to be the case that the ex ante forecast load impact (represented by the dark blue bars) is slightly lower than the ex post load impact (represented by the light blue bars). However, when we use only the PY2013 ex post load impacts to develop the ex ante forecast, the ex ante load impacts (represented by the orange bars in this case) are somewhat higher than the ex post load impacts.

Figure 7.2: Comparison of Ex Post and Ex Ante Load Impacts, SCE



7.3 SDG&E

7.3.1 Previous versus current ex post

Table 7.10 only includes results for DBP-DA (Navy). Note that this variant of DBP differed somewhat in PY2012 and did not exist prior to that program year. We do not include DBP-DO in the table because it did not exist prior to PY2013.

Table 7.10: Comparison of Average Event-day Ex Post Impacts (in MW) in PY 2012 and PY 2013, *SDG&E*

Level	Outcome	PY2012	PY2013
Total	# SAIDs	1	8
	Reference (MW)	10	40
	Load Impact (MW)	5	6
Per SAID	Reference (kW)	10,027	5,058
	Load Impact (kW)	5,057	719
	% Load Impact	50%	14.2%

The total load impact for this customer (the eight service accounts in PY2013 are all from the same customer) did not change substantially across program years, but the total reference load increased by a factor of four. This reduces the percentage load impact from 50 percent to 14 percent. Note that we do not use PY2012 result in our ex ante forecast because we do not believe it is sufficiently comparable to PY2013.

7.3.2 Previous versus current ex ante

In this sub-section, we compare the ex ante forecast prepared following PY 2012 (the "previous study") to the ex ante forecast contained in this study (the "current study"). Table 7.11 presents this comparison for the DBP-DA (Navy) 2014 ex ante forecasts of the 1-in-2 August peak day. In this case, there is no difference between the program- and portfolio-level impacts. We do not include DBP-DO because the program did not exist prior to PY2013.

Table 7.11: Comparison of Ex Ante Impacts from PY 2012 and PY 2013 Studies, *SDG&E*

Level	Outcome	Program Level	
		Previous Study 2014	Current Study 2014
Total	# SAIDs	1	8
	Reference (MW)	9.2	42.0
	Load Impact (MW)	4.7	6.0
Per SAID	Reference (kW)	9,225	5,252
	Load Impact (kW)	4,670	747
	% Load Impact	50.6%	14.2%

Both forecasts assumed that future enrollments would match current enrollments. Because seven service accounts were added to the program in PY2013, the resulting ex ante forecast is quite different.

7.3.3 Previous ex ante versus current ex post

The ex ante forecast prepared following PY2012 included only one DBP service account. This service account is one of the three currently enrolled in DBP-DO. (All three are associated with the same customer and premise ID.) We found an average DBP-DO load impact of 4.5 MW during PY2013, compared to an average ex ante load impact of 4.7 MW from the 1-in-2 typical event day forecast following PY2012. Though these values are close to one another, it is difficult to assess the accuracy of the forecast because of the added service accounts.

DBP-DA did not exist in PY2012, so no ex ante forecast was prepared for that program.

7.3.4 Current ex post versus current ex ante

Table 7.12 describes the factors that differ between the ex post and ex ante load impacts for SDG&E's DBP-DA (Navy) customer. We note that the ex post and ex ante load impacts nearly match, so there is essentially no difference to explain. In both cases, we find a percentage load impact of 14.2 percent with only a 0.1 MW difference in the level of load impacts (5.7 MW for the ex post event and 5.8 MW for the September 2014 1-in-2 peak day).

Table 7.12: SDG&E DBP-DA Ex Post versus Ex Ante Factors

Factor	Ex Post	Ex Ante	Expected Impact
Weather	84.0 degrees Fahrenheit during HE 14-17 on the sole event day	84.8 degrees Fahrenheit during HE 14-17 on 1-in-2 Sep. peak day	Little difference in temperature, so a small effect.
Event window	HE 14-17	HE 14-18 in Apr-Oct; HE 17-21 in Nov-Mar.	Minimal in summer; non-summer load impacts are speculative as we have not observed events in those months.
% of resource dispatched	All	All	None
Enrollment	8 service accounts	8 service accounts	None. We assume that enrollment does not change in the forecast period.
Methodology	SAID-specific regressions using own within-subject analysis.	Reference loads are simulated from SAID-specific regressions.	Small differences between simulated ex ante and estimated ex post reference loads

Turning now to SDG&E's DBP-DO, Table 7.13 shows a comparison of ex post and ex ante load impacts. The average reference loads and load impacts are calculated across the relevant event hours. The ex ante load impacts are taken from the 2014 1-in-2 September peak day. Notice that the reference load, load impact, and percentage load impact are somewhat lower in the ex ante forecast than in the average ex post event day, though the differences are (arguably) not large.

Table 7.13: Comparison of Ex Post and Ex Ante Load Impacts, SDG&E DBP-DO

Date	Event Hours	Reference (MW)	Load Impact (MW)	Temp.	% LI
8/30/2013	HE 13-16	9.9	2.9	87.3	29.4%
9/5/2013	HE 14-17	12.7	6.0	82.0	47.1%
Avg. Ex Post		11.3	4.4	84.6	39.3%
Ex Ante Sep. 1-in-2	HE 14-18	10.1	3.8	84.6	37.9%

Table 7.14 contains descriptions of the potential sources of differences between the ex post and ex ante load impacts shown in Table 7.13. There are two primary sources. First, the percentage load impacts for the ex ante scenarios will not exactly match the average ex post percentage load impact because we need to adapt the varying ex post event windows to a different ex ante event window. Therefore, while the ex ante percentage load impact is based on the ex post load findings, the values do not exactly match.

The second primary source of differences between the ex post and ex ante load impacts is that the customer's load level can vary dramatically across days. Since we simulate ex ante references loads based on "typical" usage patterns, the simulated reference load may differ from the observed load (or estimated reference load) for any one historical day.

The variability in DBP-DO load is illustrated in Figure 7.3, which shows the daily load profiles for all non-holiday weekdays from August 30 through September 30, 2013. The two bold dashed lines represent the loads on DBP-DO event days. The high non-event day load (shown in green) is for September 25, which was a mild day, illustrating that high load are not necessarily driven by cooling load for this customer.

Table 7.14: SDG&E DBP-DO Ex Post versus Ex Ante Factors

Factor	Ex Post	Ex Ante	Expected Impact
Weather	84.7 degrees Fahrenheit during HE 14-16 on average event day	84.3 degrees Fahrenheit during HE 14-16 on 1-in-2 Sep. peak day	Little difference in temperature, so no effect
Event window	HE 13-16 and HE 14-17.	HE 14-18 in Apr-Oct; HE 17-21 in Nov-Mar.	Minimal in summer. There is not a perfect match of percentage load impacts because we need to conform varying ex post event windows to a different ex ante window. Non-summer load impacts are speculative as we have not observed events in those months.
% of resource dispatched	All	All	None
Enrollment	3 service accounts	3 service accounts	None. We assume that enrollment does not change in the forecast period.
Methodology	SAID-specific regressions using own within-subject analysis.	Reference loads are simulated from SAID-specific regressions.	Because customer load can vary considerably across days, simulated ex ante reference loads can differ from ex post reference loads for specific event days.

Figure 7.3: Observed Loads for SDGE DBP-DO, August 30 - September 30, 2013

These results have been removed due to confidentiality concerns.

8. Recommendations

Based on the performance of dually enrolled customers, the utilities should continue to encourage customers in BIP and the aggregator programs (AMP and CBP) to enroll in DBP. They tend to be the most responsive customers in DBP and provide a means for the utilities to increase the amount of demand response that can be obtained on DBP-only event days.

In addition, the day-of adjustments to the 10-in-10 baselines appear to significantly improve the accuracy of, and reduce the bias in, program baseline performance. The improvements are not very sensitive to the level of the day-of adjustment cap, though there is some evidence that a cap of 20 to 40 percent would strike a reasonable balance between improved performance and limited risk (i.e., preventing extreme adjustments).

Appendices

The following Appendices accompany this report. Appendix A is the validity assessment associated with our ex post load impact evaluation. The additional appendices are Excel files that can produce the tables required by the Protocols. Note that the SDG&E appendices (D and G) are not provided to the public due to confidentiality concerns.

DBP Study Appendix B	PG&E Ex-Post Load Impact Tables
DBP Study Appendix C	SCE Ex-Post Load Impact Tables
DBP Study Appendix D	SDG&E Ex-Post Load Impact Tables
DBP Study Appendix E	PG&E Ex-Ante Load Impact Tables
DBP Study Appendix F	SCE Ex-Ante Load Impact Tables
DBP Study Appendix G	SDG&E Ex-Ante Load Impact Tables

Appendix A. Validity Assessment

A.1 Model Specification Tests

A range of model specifications were tested before arriving at the model used in the ex post load impact analysis. The basic structure of the model is shown in Section 3.2.1. The tests are conducted using average-customer data (by utility) rather than at the individual customer level. Model variations include 18 different combinations of weather variables. The weather variables include: temperature-humidity index (THI)[26]; the 24-hour moving average of THI; heat index (HI)[27]; the 24-hour moving average of HI; cooling degree hours (CDH)[28], including both a 60 and 65 degree Fahrenheit threshold; the 3-hour moving average of CDH; the 24-hour moving average of CDH; the one-day lag of cooling degree days (CDD)[29]. A list of the 18 combinations of these variables that we tested in provided in Table A.1.

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

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

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

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

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

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

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

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

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

In order to select event-like non-event days, we created an average weather profile using the load-weighted average temperature across customers, each of which is associated with a weather station.

We selected days according to the average event-hour temperature (e.g., hours-ending 13 through 20 for PG&E), omitting holidays, weekends, and event days for programs in which DBP customers are dually enrolled (e.g., DBP). For the most part, the selection involved selecting the hottest qualifying days. In some cases, days are selected to reflect conditions on milder event days (e.g., for PG&E, the September 18 event-like day is a proxy for the September 10 event day). Table A.2 lists the event-like non-event days selected for each program.

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

PG&E	SCE	SDG&E DA	SDG&E DO
6/27/2013	5/20/2013	8/28/2013	8/27/2013
6/28/2013	6/4/2013	8/29/2013	8/28/2013
7/9/2013	6/11/2013	8/30/2013	9/3/2013
7/24/2013	6/12/2013	9/3/2013	9/6/2013
8/13/2013	7/8/2013	9/4/2013	
8/16/2013	7/9/2013		
8/30/2013	7/16/2013		
9/6/2013	8/22/2013		
9/18/2013	9/3/2013		
	9/10/2013		

A.1.2 Results from Tests of Alternative Weather Specifications

For each utility, we tested 18 different sets of weather variables. The aggregate load used in conducting these tests was constructed separately for each utility (and separately for SDG&E's DBP-DA and DBP-DO) and included only customers who submitted a bid on at least one event day.

The tests are conducted by estimating one model for every utility/program (4), specification (18), and event-like day (9 for PG&E, 10 for SCE, 5 for SDG&E DBP-DA, and 4 for SDG&E DBP-DO). Each model excludes one event-like day from the estimation model and uses the estimated parameters to predict the usage for that day. The MPE and MAPE are calculated across the event windows of the withheld days.

Table A.3 summarizes the adjusted R-squared, mean percentage error (MPE), and mean absolute percentage error (MAPE) the winning specification for each program. The bias is quite low for the PG&E, SCE, and SDG&E-DA models, but fairly high for the SDG&E-DO model. The high bias and error rates for the SDG&E-DO model is likely due to the fact that it contains only one customer that displays somewhat large variations in load across days. Model performance tends to improve as the sample size increases, since customer-specific idiosyncrasies get averaged out. This helps explain the superior performance of the PG&E and SCE models, which are much larger programs than either SDG&E DBP program.

Table A.3: Specification Test Results

Utility/Program	Selected Specification Number	Adjusted R^2	MPE	MAPE
PG&E	7	0.79	1.7%	2.8%
SCE	10	0.95	-0.6%	1.8%
SDG&E DA	10	0.82	-1.4%	7.3%
SDG&E DO	10	0.72	-8.4%	8.9%

For each specification, we estimated a single model that included all of the days (i.e., not withholding any event-like days), but using a single set of actual event variables (i.e., a 24-hour profile of the average event-day load impacts). Figures A.1 through A.4 show the estimated hourly load impacts for each of the 18 models by utility/program. The load impacts for the selected specification are highlighted in bold in each of the figures. With the possible exception of SDG&E's DBP-DO program (shown in Figure A.4), the results of these tests indicated that very little is at stake when selecting from the specifications, as the load impact profile was quite stable across them.[30]

[30] The shape of the load impact profile for PG&E's DBP does not match the ex post average event day results, which are based on customer-specific regression models. There are two reasons for this. First, the event variables in these models include the three "partial" event days as well as the three "full" event days (during which all DBP customers were called). Second, the aggregate data do not necessarily reflect what happens at the customer level (though it usually comes closer than we have found in this case). In our review of the ex post load impacts, we found several service accounts that contributed to an ex post load impact profile that is not reflected in program-level data.

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

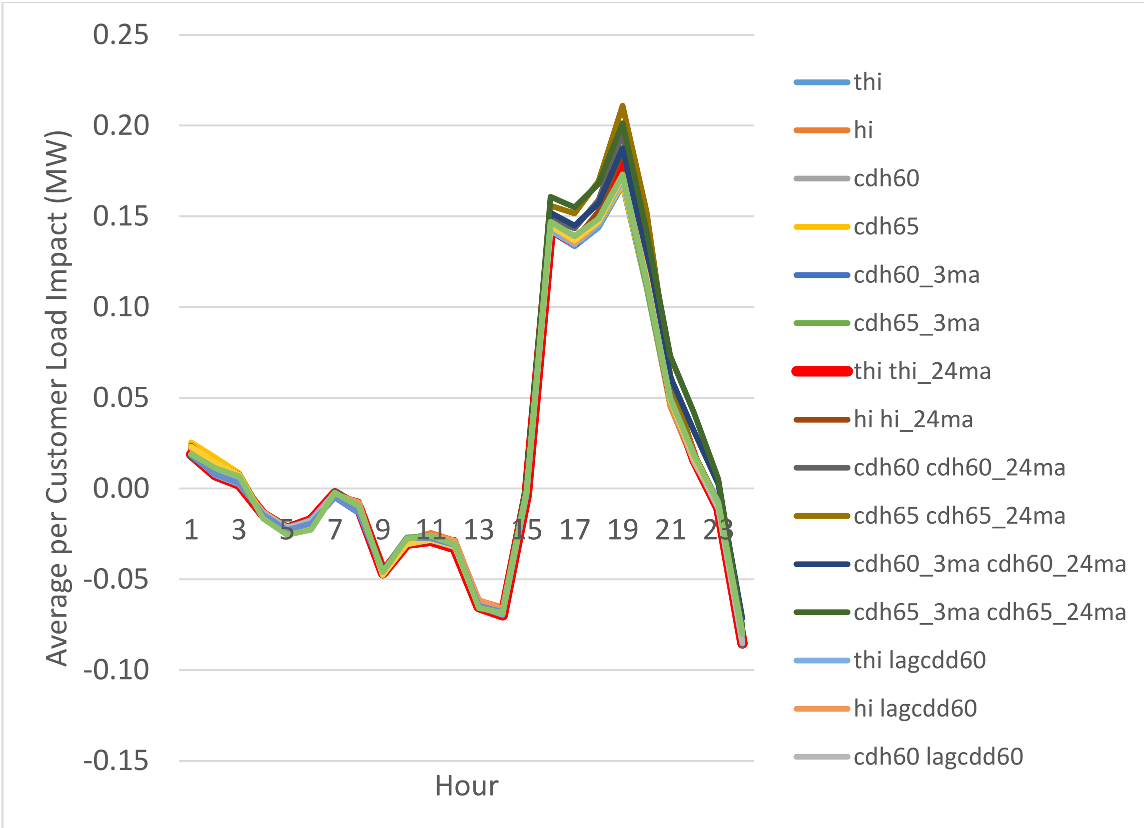

Figure A.2: Average Event-Hour Load Impacts by Specification, *SCE Models*

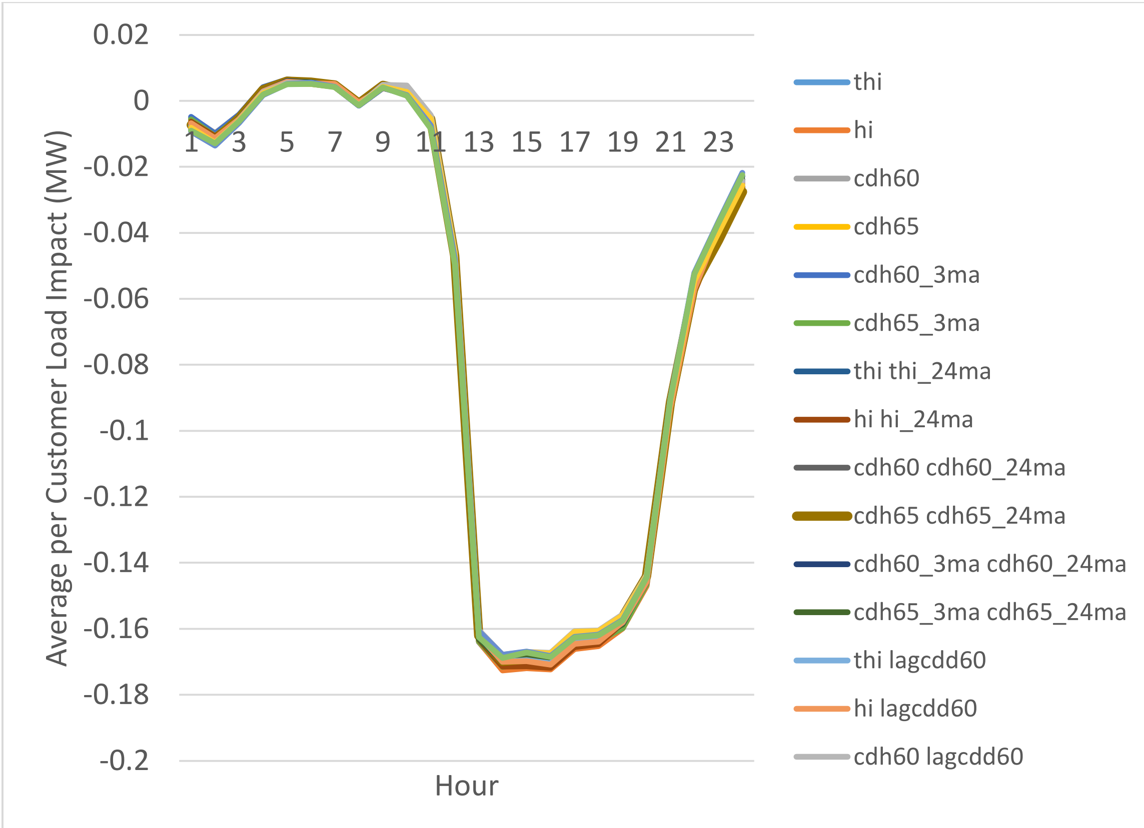

Figure A.3: Average Event-Hour Load Impacts by Specification, *SDG&E DA Models*

These results have been removed due to confidentiality concerns.

Figure A.4: Average Event-Hour Load Impacts by Specification, *SDG&E DO Models*

These results have been removed due to confidentiality concerns.

A.1.3 Synthetic Event Day Tests

For the specification selected from the testing described in Section A.1.2, we conducted an additional test. The selected specification was estimated on the aggregate customer data (averaged across all customers who submitted a bid on at least one event day), including a set of 24 hourly “synthetic” event-day variables. These variables equaled one on the days listed in Table A.2, with a separate estimate for each hour of the day.

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

Table A.4 presents the results of this test for each utility, showing only the coefficients during the event window (e.g., hours-ending 13 through 20 for PG&E and SCE). The values in parentheses are p-values, or measures of statistical significance. A p-value less than 0.05 indicates that the estimated coefficient is statistically significantly different from zero with 90 percent confidence. The results for PG&E and SDG&E contain some statistically significant results, but the models perform well overall. SCE's results indicate that the specification passed the test in all hours, as none of the event-like load impacts is statistically significant. Note that SDG&E's results have been removed due to confidentiality concerns.

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

Hour	PG&E	SCE	SDG&E DA	SDG&E DO
13	-0.01 (0.34)	0.011 (0.078)		
14	-0.02 (0.20)	0.012 (0.058)		
15	-0.01 (0.49)	0.007 (0.228)		
16	-0.01 (0.41)	0.007 (0.232)		
17	-0.02 (0.13)	0.007 (0.275)		
18	-0.03 (0.04)	0.005 (0.393)		
19	-0.04 (0.01)	0.008 (0.190)		
20	-0.03 (0.04)	0.009 (0.161)		

A.2 Comparison of Predicted and Observed Loads on Event-like Days

The model specification tests are based on the ability of the model to predict program load on event-like non-event days. Figures A.5 through A.8 illustrate the average predicted and observed loads across the event-like days. In each figure, the solid line represents the observed load and the dashed line represents the load predicted by the statistical model.

Figure A.5 shows that the PG&E predicted loads are quite close to the observed loads for the event-like non-event days. Figure A.7 shows that the SDG&E DBP-DA predicted loads are slightly lower than the observed loads. The under-prediction is larger for SDG&E DBP-DO, as shown in Figure A.8. In this case, much of the prediction error (and the observed spike in the early morning hours) is due to an odd observed load profile on

September 6. A limited number of comparable event-like days prevents us from replacing this day in the analysis.

Figure A.5: Average Predicted and Observed Loads on Event-like Days, *PG&E*

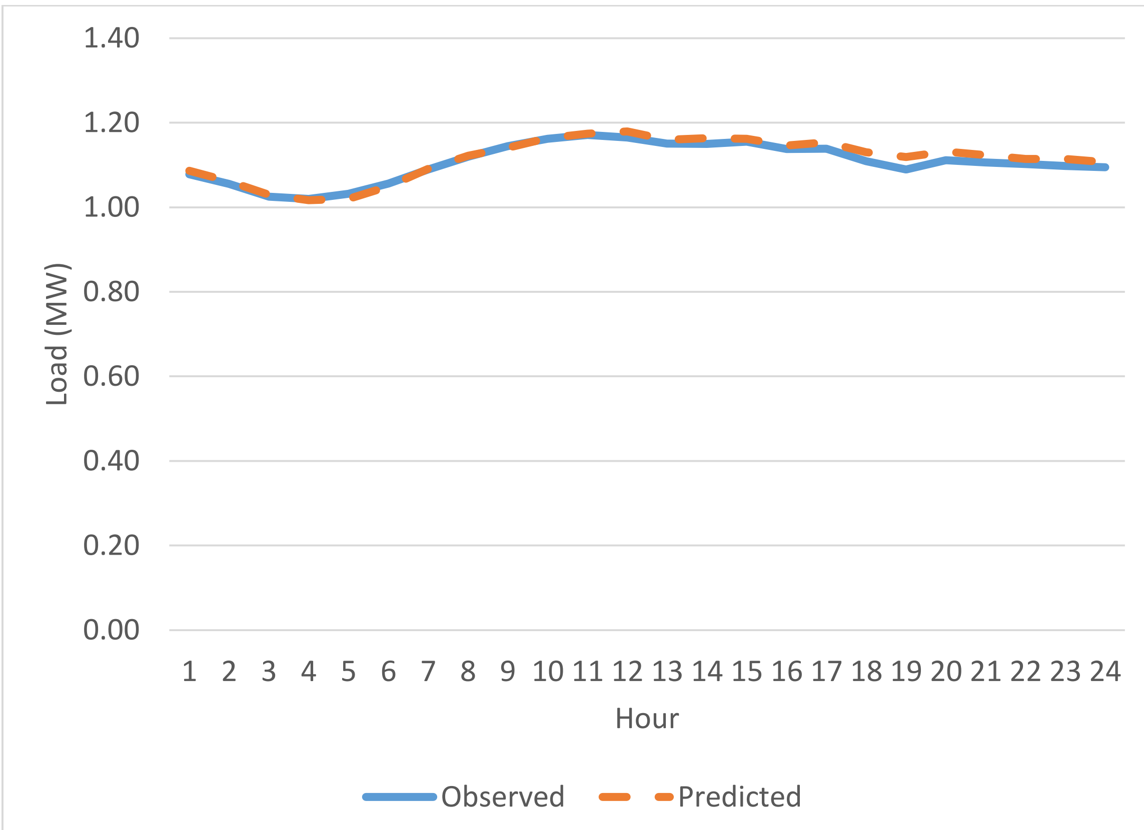

Figure A.6: Average Predicted and Observed Loads on Event-like Days, *SCE*

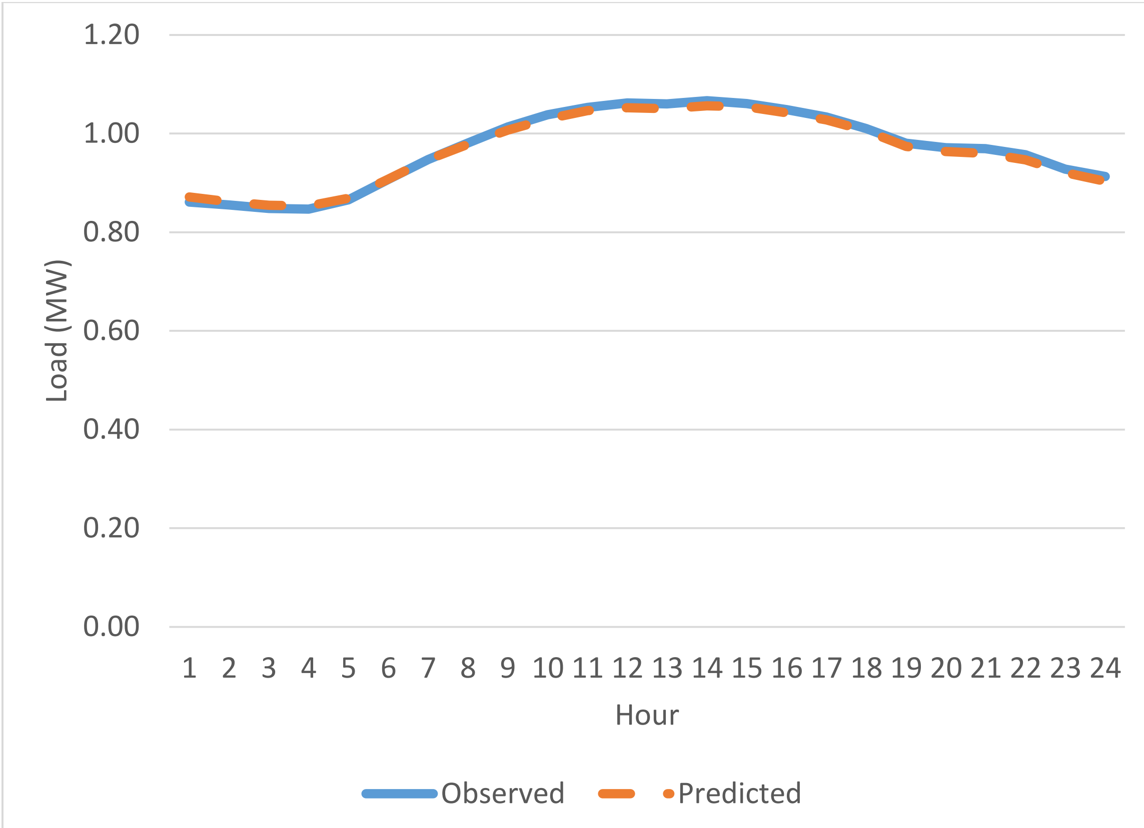

Figure A.7: Average Predicted and Observed Loads on Event-like Days, *SDG&E DA*

These results have been removed due to confidentiality concerns.

Figure A.8: Average Predicted and Observed Loads on Event-like Days, *SDG&E DO*

These results have been removed due to confidentiality concerns.

A.3 Refinement of Customer-Level Models

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