



2013 Load Impact Evaluation of California's Statewide Base Interruptible Program

Submitted to
Southern California Edison Co.
Pacific Gas and Electric Co.
San Diego Gas and Electric Co.

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1 Executive Summary

Each of California's three electric investor-owned utilities (IOUs), Southern California Edison Co. (SCE), Pacific Gas and Electric Co. (PG&E) and San Diego Gas and Electric Co. (SDG&E), offer the Base Interruptible Program (BIP). Although minor differences in the tariffs exist across the three IOUs, for all three, BIP is a tariff-based, emergency-triggered demand response (DR) program that the IOUs can dispatch for California Independent System Operator (CAISO) system warnings and emergencies local to the individual IOUs' transmission or distribution systems. Customers enrolled in BIP receive incentive payments in exchange for committing to reduce their electrical usage to a contractually-established level referred to as the Firm Service Level (FSL). Participants who fail to reduce load down to or below their FSL are subject to a substantial financial excess energy charge assessed on a kWh basis. In addition, SDG&E participants who fail to reduce load down to or below their FSL will have their FSL reset up to their energy usage during the event, thus lowering their capacity payment in future months. At PG&E, BIP participants who fail to reduce load down to or below their FSL have the option to either modify their FSL to an achievable level that meets program requirements, de-enroll from the program or retest at the current FSL. As of January 2013, enrollment in BIP equaled 646 accounts for SCE, 280 accounts for PG&E and 7 accounts for SDG&E.

One of the most important issues facing BIP is the cap on emergency DR programs that was adopted in 2010 by the IOUs, CAISO and the California Public IOUs Commission (CPUC).[1] This cap limits the growth of emergency DR programs to a certain percentage of the recorded all-time coincident CAISO peak load. For 2013, the limit was 2.5% with a 10% tolerance band. The cap will gradually lower to 2% of CAISO peak load without a tolerance band from 2016 onwards. A specific portion of the cap is allocated to each IOU. Considering that SCE is near its allocation of the cap, BIP enrollment is projected to remain constant throughout the ex ante forecast period (2014–2024). SDG&E BIP enrollment is also expected to remain constant. Likewise, PG&E does not expect its BIP enrollment to change over the forecast horizon.

This report documents the ex post and ex ante load impact estimates associated with BIP for all three of California's IOUs. Ex post estimates are provided for 2013 events. Ex ante estimates are provided for the years 2014 through 2024, including a base year forecast for 2013 that assumes 2013 enrollments.

1.1 Ex Post Load Impact Estimates

This report provides ex post load impact estimates for events called in 2013. Each IOU called a territory-wide BIP test event in 2013.

SCE held a system-wide BIP test event on September 19 from 3 to 5 PM. Overall, 646 customers participated in the event. The aggregate load drop during the hour 4 to 5 PM was 687 MW, representing an 84% reduction relative to the estimated reference load of 817 MW. From 4 to 5 PM, aggregate load fell to 130 MW and customers provided 94% of the expected load reduction given the aggregate FSL of 84.5 MW.

[1] CPUC decision (D.) 08-04-050 issued on April 28, 2008 with Attachment A.

PG&E's system-wide BIP test event was held on July 2 from 3 to 7 PM. The event included all of the 280 customers that were enrolled in BIP at that time. The aggregate load drop during the event period was 216 MW. This represents roughly a 74% reduction relative to the reference load of 291 MW. In aggregate, customers provided 95% of the expected load reduction given the aggregate FSL of 63.5 MW. PG&E also called a retest event for certain customers on August 27 from 2 to 6 PM. The average per-customer load drop over the four-hour event retest event period was 134 kW. This represents a 29% reduction relative to the reference load of 462 kW. On average, retested customers provided around 46% of the expected load reduction given the average FSL of 174 kW.

SDG&E called a test BIP event on September 5 that lasted from 1 to 5 PM for all customers. All customers received 30-minute notice of the event. In total, seven customers participated in the event. The average aggregate load drop from 1 to 5 PM was 1.7 MW. Overall, the load impact represents slightly more than a 100% reduction relative to the reference load of 3.2 MW.

1.2 Ex Ante Load Impact Estimates

BIP is a large, statewide emergency resource that is expected to have stable enrollment over the next few years. Figure 1-1 shows the amount of DR available through BIP from 2014 through 2024 by IOU. For the August monthly peak day in a 1-in-2 weather year, the program is projected to deliver 893 MW in 2014. The program is not expected to grow during the forecast horizon due to the cap on emergency-based DR programs and no assumptions for customer load growth. In each forecast year, 72.4% of the aggregate load reduction comes from SCE, 27.4% comes from PG&E and the remaining 0.2% from SDG&E. These results are not significantly different under 1-in-10 weather year conditions because BIP customers are not weather-sensitive on average.

Figure 1-1: 2014–2024 Aggregate Load Impacts by IOU and Forecast Year August Monthly Peak Day in a 1-in-2 Weather Year

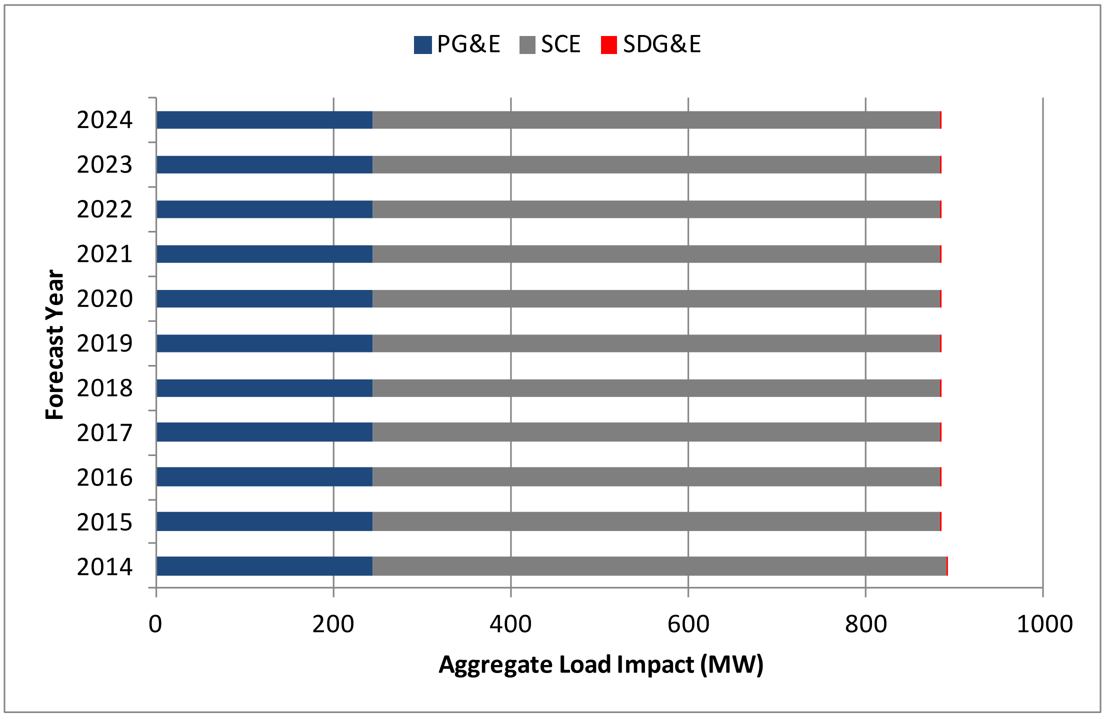
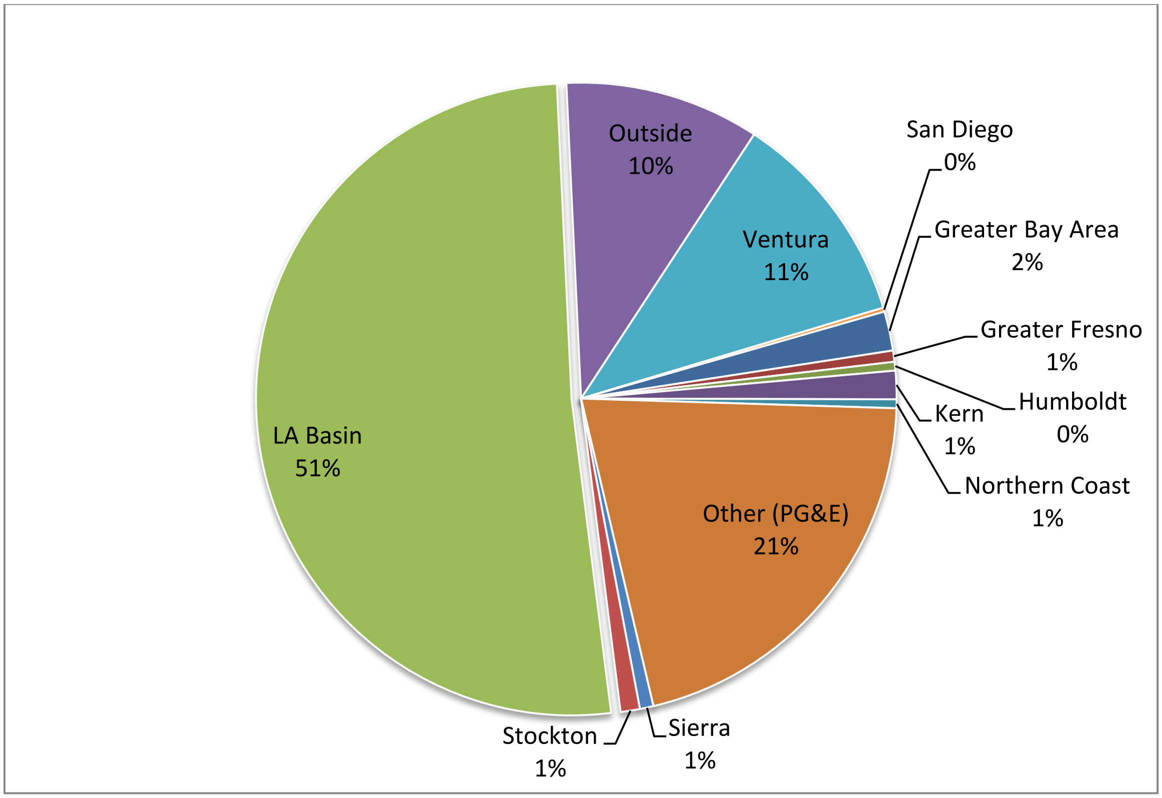


Figure 1-2 shows the distribution of statewide aggregate load impacts in 2016 by local capacity area (LCA). LCAs are CAISO-designated planning regions for which IOUs must meet local resource adequacy requirements. For a typical event day under 1-in-2 weather year conditions in 2016, the statewide aggregate load impact is 889 MW. The LA Basin LCA in SCE's service territory comprises 51% of the statewide aggregate load impact. PG&E's Other LCA is the only area outside of SCE's territory that provides more than 3% of the statewide aggregate load impact.

Figure 1-2: Distribution of 2016 Statewide Aggregate Load Impacts by Local Capacity Area August Monthly Peak Day under 1-in-2 Weather Conditions Total Statewide Aggregate Impact = 889 MW



2 Introduction and Program Summary

This report documents the 2013 ex post load impact estimates for California's statewide Base Interruptible Program (BIP) and provides ex ante load impact estimates from 2013 through 2024. Each of California's three electric IOUs, Southern California Edison Co. (SCE), Pacific Gas and Electric Co. (PG&E) and San Diego Gas and Electric Co. (SDG&E), offer BIP. Although minor differences in the tariffs exist across the three IOUs, for all three, BIP is a tariff-based, emergency demand response (DR) program that the IOUs can dispatch for California Independent System Operator (CAISO) system warnings and emergencies local to the individual IOUs' transmission or distribution systems. Customers enrolled in BIP receive incentive payments in exchange for committing to reduce their electricity usage to a contractually-established level referred to as the Firm Service Level (FSL). Participants who fail to reduce load down to or below their FSL are subject to a substantial financial penalty assessed on a kWh basis.

Until recently, the state's IOUs could only operate BIP when the CAISO determined that system-wide conditions reached a Stage 2 emergency (e.g., when operating reserves are less than 5%) or on a test-event basis. At the request of the CAISO, the California Public Utilities Commission (CPUC) ruled[2] that the three IOUs must modify their tariffs. The revised tariffs allow the IOUs to call BIP after CAISO has publicly issued a warning notice and has determined that a stage 1 emergency is imminent when it has exhausted all other options to prevent further degradation of its operating reserves. The other triggering conditions for BIP (local emergencies, CAISO stage 1, 2 and 3 emergencies or test events) remain in place.

This report provides ex post load impact estimates for events called in 2013. Each IOU called a BIP test event in 2013, and PG&E called a retest event for certain customers who failed to reach their FSL during the 2013 test event. SCE called a test event on September 19 from 3 to 5 PM. PG&E dispatched a test event on July 2 from 3 to 7 PM and a retest event for certain customers on August 27 from 2 to 6 PM. There was one BIP test event held at SDG&E in 2013. That event occurred on September 5 and lasted from 1 to 5 PM.

Ex ante impact estimates for all three programs are also provided for a 1-in-2 weather year and a 1-in-10 weather year from 2014 through 2024. The load impact estimates presented here are intended to conform to the requirements of the CPUC Demand Response Load Impact Protocols (Protocols).[3]

2.1 Cap on Emergency DR Programs

One of the most important issues facing the statewide BIP is the cap on emergency DR programs that was adopted in 2010 by the IOUs, CAISO and CPUC.[4] This cap limits the growth of emergency DR programs to a certain percentage of the recorded all-time coincident CAISO peak load. For 2013, the limit was 2.5% with a 10% tolerance band. The all-time coincident CAISO peak load stands at 50,270

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[2] CPUC resolution E-4220. January 29, 2009.

[3] CPUC decision (D.) 08-04-050 issued on April 28, 2008 with Attachment A.

[4] CPUC D.10-06-034, Appendix A issued on June 25, 2010.

MW, the 2014 cap is therefore 1,383 MW. The cap will gradually lower to 2% of CAISO peak load without a tolerance band from 2016 onwards. The cap allocated to each IOU as follows:

- PG&E: 453 MW;
- SCE: 906 MW; and
- SDG&E: 23 MW.

If a IOU exceeds its cap, the CPUC may reduce the amount of resource adequacy credit allocated towards emergency DR programs or ask the IOU to modify the program in order to reduce enrollment.

Although the IOUs have other emergency programs in their DR portfolios, this cap has the largest impact on BIP because it comprises more than half of the state's emergency DR resources. As a result, each IOU will need to closely monitor BIP enrollment in order to maximize the potential of this important resource, but not exceed the cap.

2.2 Overview of SCE's BIP Program

SCE’s BIP program is designed for customers and aggregators with demands of 200 kW and above. The program includes two notification options: option A with a 15-minute notification lead time and option B with a 30-minute notification requirement. Interruption events for an individual BIP customer or aggregated group are limited to a single 6-hour event per day, and no more than 10 events per calendar month and 180 hours per calendar year. An interruption event may be called at any time during the year. BIP incentive payments at SCE vary by service voltage, season and time of day.

SCE’s I-6 program was a predecessor interruptible tariff designed for large customers with demands of 500 kW and above. The I-6 tariff has been closed to new enrollment since 1996. Starting in 2006, SCE began transitioning I-6 customers to BIP. The transition was complete by the end of 2008. As of January 2013, SCE had 646 service accounts enrolled in the BIP program, of which 88% were in the 30-minute notification option. As indicated in Table 2-1, the largest number of accounts are from the manufacturing sector (57% of the total). There has been little change in BIP enrollment at SCE since 2012 when there were 647 customers participating in the program and the manufacturing sector accounted for 58% of total enrollment.

Table 2-1: Number of Accounts in SCE's BIP Program by Industry

Industry	Number of Accounts
Agriculture, Mining & Construction	56
Manufacturing	369
Wholesale, Transport & Other Utilities	72
Retail Stores	41
Offices, Hotels, Finance, Services	35
Schools	68
Institutional/Government	5
Total	**646**

SCE's service territory includes three CAISO local capacity areas (LCAs).[5] The vast majority of service accounts (551 out of the 646 BIP accounts) are in the LA Basin LCA, 72 are located in the Ventura LCA and the remaining 23 are in the Outside LA Basin LCA.

In the ex ante analysis, it is assumed that SCE enrollment remains the same from 2014 through 2024. Considering that SCE is close to its cap on emergency DR programs, they do not plan to actively recruit new BIP customers.

There was one test event held for SCE's BIP program in 2013. That event occurred on September 19 and lasted for two hours, from 3 to 5 PM. Section 4.1 summarizes the ex post results for this event.

2.3 Overview of PG&E's BIP

Customers can enroll in PG&E's BIP either directly or through an aggregator. The program is designed for customers with minimum average monthly demand of at least 100 kW. Customers enrolled in PG&E BIP are notified at least 30 minutes in advance of an event. Previously, there was an option B with a 4-hour notification lead time, but it is no longer offered. At the time option B was discontinued, all PG&E BIP customers were enrolled in the 30-minute notification option. Curtailment events for an individual BIP customer or an aggregated group of customers are limited to a single 4-hour event per day, no more than 10 events per month and no more than 180 event hours per calendar year. A curtailment event may be called under BIP at any time during the year. BIP incentive payments at PG&E vary by the amount of load drop potential, given a customer's FSL and average monthly on-peak or partial-peak demand.

[5] Local capacity area (or LCA) refers to a CAISO-designated load pocket or transmission-constrained geographic area for which a IOU is required to meet a local Resource Adequacy capacity requirement. There are currently three LCAs within SCE's service territory, seven in PG&E's service territory and one in SDG&E's service territory. In addition, PG&E has many accounts not located within any specific LCA. These accounts are categorized here as part of the "Other" LCA region.

As of January 2013, there were 280 accounts[6] enrolled in PG&E's BIP. Since 2012, the number of participants has grown by 28 accounts. Table 2-2 shows the distribution of service accounts by industry grouping. As in SCE's BIP, the largest number of accounts comes from the manufacturing sector (34% of the total).

Table 2-2: Number of Accounts in PG&E's BIP by Industry

Industry	Number of Accounts
Agriculture, Mining & Construction	44
Manufacturing	96
Wholesale, Transport & Other Utilities	55
Retail Stores	34
Offices, Hotels, Finance, Services	21
Schools	20
Institutional/Government	10
Total	**280**

Table 2-3 shows the distribution of PG&E BIP accounts across LCAs within PG&E's service territory. Most BIP participation comes from the Other and Greater Bay Area LCAs. Some LCAs have 15 or fewer BIP participants – the participation counts for those LCAs have been combined with the count of customers in the Other LCA category.

Table 2-3: Number of Service Accounts in PG&E's BIP by LCA

LCA	Number of Accounts
Greater Bay Area	66
Kern	26
North Coast and North Bay	16
Other / Combined LCAs	132
Stockton	40
Total	**280**

PG&E does not expect enrollment in its BIP to change over the forecast horizon of 2014 through 2024.

6 PG&E tracks participation in terms of service agreements, but in order to be consistent with the terminology used for SCE and SDG&E, PG&E service agreements are referred to as accounts in this report.

There was one system-wide event for PG&E's BIP in 2013, on July 2 from 3 to 7 PM. A retest event was called for certain customers on August 27 from 2 to 6 PM. Section 5.1 summarizes the ex post results for this event.

2.4 Overview of SDG&E's BIP Program

SDG&E BIP is a voluntary program that offers participants a monthly capacity bill credit in exchange for committing to reduce their demand to a contracted FSL on short notice during emergency situations. Non-residential customers who can commit to curtail 15% of monthly peak demand with a minimum load reduction of 100 kW are eligible for the program. Customers in BIP are notified no later than 30 minutes before the event. Previously, there was an option B with a 3-hour notification lead time, but it is no longer offered. Incentive payments are $12 per kW during the months of May through October and $2 per kW during all other months. Curtailment events for an individual BIP customer are limited to a single 4-hour event per day, no more than 10 events per month and no more than 120 event hours per calendar year. A curtailment event may be called for BIP at any time during the year.

Participation in SDG&E's program has been relatively low. There was one participant in 2006 and three in 2007. Participation grew from 3 to 20 participants in 2008, but fell to 19 participants as of January 2010. By the end of 2010, there were 21 accounts enrolled in SDG&E BIP and enrollment remained at that level through the end of 2011. However, by May of 2012, enrollment dropped to 11 accounts and dropped further to seven accounts in 2013. The current distribution of accounts by industry is shown in Table 2-4. There is only one LCA in SDG&E's service territory.

In 2012, SDG&E implemented a program change with respect to how the FSL is calculated for the BIP program. Beginning in 2012, if a customer does not reduce its load below the FSL during an event, the FSL is raised to the amount of energy the customer used during the event. Since the monthly capacity payment is equal to the average monthly on-peak energy use load minus the FSL, raising the FSL lowers future capacity payments to customers who did not perform during the event. This program change successfully encouraged free-riders to opt out of the program in both 2012 and 2013 because it greatly reduces the potential for a free-rider to earn capacity payments during months with no events.

Table 2-4: Number of Service Accounts in SDG&E's BIP Program by Industry

Industry	Number of Accounts
Agriculture, Mining & Construction	2
Manufacturing	1
Wholesale, Transport & Other Utilities	1
Retail Stores	3
Total	**7**

Enrollment in SDG&E's BIP program is expected to remain stable over the forecast horizon 2014–2024.

There was one event held for SDG&E's BIP program in 2013. That event occurred on September 5 and lasted for four hours, from 1 to 5 PM.

2.5 Report Structure

The remainder of this report is organized as follows. Section 3 discusses the methodology for the ex post and ex ante evaluations. Sections 4, 5 and 6 include the ex post and ex ante load impact estimates for each IOU and Section 7 contains recommendations for improving the program. All of the required ex post and ex ante hourly load impact tables are provided in an electronic table generator under separate cover.

3 Methodology

This section discusses the methodology that was used to develop ex post and ex ante load impact estimates for BIP. It covers the regression model development and an assessment of its accuracy.

3.1 Model Development

The first step in calculating event day impacts is estimating the reference loads. Reference loads indicate how customers would have behaved in the absence of a DR event. Reference loads are calculated using regression analysis on customer usage on days that are similar to, but not actual, event days. The observed loads are then subtracted from the reference loads to calculate ex post impacts. In ex ante analysis, historical weather data is used to determine the weather patterns of a typical BIP event day. The same models used in the ex post analysis are then run on these typical BIP event days to determine ex ante reference loads. However, in ex ante analysis, there are no observed loads to compare to the reference loads. In order to calculate ex ante impacts, impacts are calculated as a function of:

- Forecasted load in the absence of a DR event (i.e., the reference load);
- The participant's FSL; and
- Over/under performance relative to the FSL.

The reference loads are estimated using the regression models presented in Figure 3-1, Figure 3-2 and Figure 3-3. Over/under performance, which is a measure of how well customers perform during BIP events relative to the FSL, is determined for each industry using historical event data. The number of events is too small to be used in a regression to predict the load with DR. Instead, impacts were estimated using average historical performance by industry, relative to FSL.

Eleven regression models were tested for each IOU. The final regression models used to predict reference loads were chosen based on bias and accuracy metrics. Having low bias and high accuracy across all the industries also factored into the decision. In addition, varying datasets were tested to see if it would be beneficial to include multiple years or weekends. The estimated models, with the exception of SCE, were based on one-year of hourly load data for each customer, using all 24 hours for each individual's regression. SCE's model was based on two-years of data.

The regression model was used to predict the kW load for each hour separately for each participant. The regression models were based on many variables, consisting largely of shape and trend variables (and interaction terms) designed to track variation in load across days of the week and hours of the day. Weather variables were tested and had significant impacts for certain customers. Binary variables representing season were also included to capture the change in load due to seasonal price variation. The regression models are as follows:

Figure 3-1: Reference Load Model - SCE

$$kW_t = A + B \times SummerOn_t + C \times SummerMid_t + D \times SummerOff_t + E \times WinterMid_t + \sum_{i=1}^{24}\sum_{j=1}^{5} F_{ij} \times Hour_i \times DayType_j + \sum_{i=1}^{24}\sum_{j=1}^{12} G_{ij} \times Hour_i \times Month_j + \sum_{i=1}^{24} H_i \times Hour_i \times Year2013_t + \sum_{i=1}^{24} I_i \times Hour_i \times TotalCDH_t + \sum_{i=1}^{24} J_i \times Hour_i \times TotalCDHsqr_t + \sum_{i=1}^{24} K_i \times Hour_i \times TotalHDH_t + \sum_{i=1}^{24} L_i \times Hour_i \times TotalHDHsqr_t + \sum_{i=1}^{24} M_i \times Hour_i \times CPP\_Eventday_t + \sum_{i=1}^{24} N_i \times Hour_i \times DRC\_Eventday_t + \sum_{i=1}^{24} P_i \times Hour_i \times DBP\_Eventday_t + + \sum_{i=1}^{24} Q_i \times Hour_i \times BIP\_Eventday_t + e_t$$

Figure 3-2: Reference Load Model – PG&E

$$kW_t = A + \sum_{i=1}^{24} B_i \times Hour_i \times Summer_t + \sum_{i=1}^{24} C_i \times Hour_i \times CDD_t + \sum_{i=1}^{24} D_{ij} \times Hour_i \times CDH_t + \sum_{i=1}^{24}\sum_{j=1}^{5} E_{ij} \times Hour_i \times DayType_j + \sum_{i=1}^{24}\sum_{j=1}^{12} F_{ij} \times Hour_i \times Month_j + \sum_{i=1}^{24} G_i \times Hour_i \times CPP\_Eventday_t + \sum_{i=1}^{24} H_i \times Hour_i \times DBP\_Eventday_t + \sum_{i=1}^{24} I_i \times Hour_i \times BIP\_Eventday_t + e_t$$

Figure 3-3: Reference Load Model – SDG&E

$$
\begin{aligned}
kW_t = {} & A + B \times SummerOn_t + C \times SummerMid_t + D \times SummerOff_t + E \times WinterMid_t \\
& + \sum_{i=1}^{24}\sum_{j=1}^{5} F_{ij} \times Hour_i \times DayType_j + \sum_{i=1}^{24}\sum_{j=1}^{12} G_{ij} \times Hour_i \times Month_j + \\
& + \sum_{i=1}^{24} H_i \times Hour_i \times TotalCDH_t + \sum_{i=1}^{24} I_i \times Hour_i \times TotalCDHsqr_t \\
& + \sum_{i=1}^{24} J_i \times Hour_i \times TotalHDH_t + \sum_{i=1}^{24} K_i \times Hour_i \times TotalHDHsqr_t \\
& + \sum_{i=1}^{24} L_i \times Hour_i \times CPP\_Eventday_t + \sum_{i=1}^{24} M_i \times Hour_i \times BIP\_Eventday_t + e_t
\end{aligned}
$$

Table 3-1: Variable Descriptions

Variable	Description
kW_t	hourly BIP customer load at time t
A	estimated constant term
$B-Q$	estimated parameters
CDD_t	cooling degree days (base 60)
CDH_t	cooling degree hours (base 70)
$TotalCDH_t$	total cooling degree hours (base 70) per day
$TotalHDH_t$	total number of heating degree hours (base 70) per day
$TotalCDHsqr_t$	total cooling degree hours (base 70) per day squared
$TotalHDHsqr_t$	total number of heating degree hours (base 70) per day squared
$DayType_j$	series of binary variables representing five different day types (Mon, Tues-Thurs, Fri, Sat, Sunday/Holiday)
$Month_j$	series of binary variables for each month
$Hour_i$	series of binary variables for each hour, which is interacted with all of the remaining variables because each has an impact that varies by hour
$Year2013_t$	indicates if the data is from the 2013 dataset that ranges from October 2012 – September 2013
$CPP\_Eventday_t, BIP\_Eventday_t$ $DBP\_Eventday_t, DRC\_Eventday_t$	binary variable representing each program event day if customer is also enrolled in that program
$Summer_t$	binary variables that indicate if month is between May and October for each hour
$SummerOn_t, SummerMid_t,$ $SummerOff_t, WinterMid_t$	binary variables that indicate which TOU rate block is in effect for each hour
e_t	error term

Prior BIP load impact evaluations have included assumptions for customer load growth due to recovery from the last economic downturn. No IOUs assume load growth factors for BIP customers in this year's evaluation.

3.2 Model Accuracy and Validity Assessment

Although regressions were run for each individual customer in the BIP, what matters most is that the reference loads for all customers combined, or for selected groups of customers (e.g., industry types and LCA) are accurate. The regressions are not as accurate at the individual customer level, but when aggregated, overestimates and underestimates generally balance each other out and the resulting aggregate reference load is more accurate. Given that load impacts are calculated as the difference between the reference load and the FSL (after factoring in over/under performance), any error in the estimated reference load would cause an error in the estimated load impact.

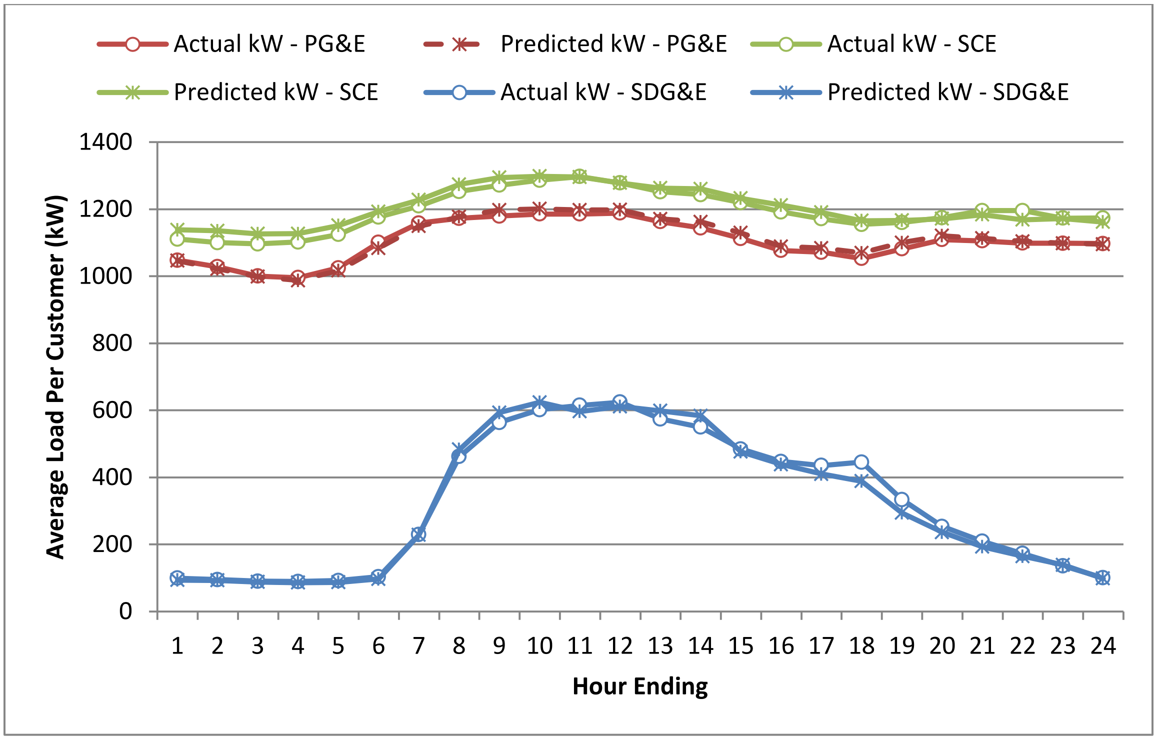
3.2.1 Out-of-sample Validation

Considering that BIP events are usually called on high system load days, it is important that the model predicts accurately on these days. In the first test of model accuracy, a series of out-of-sample validations is conducted. Rather than running the model on all of the available load data, a group of three randomly selected high system load days is withheld from the estimation. Although these three days are not included in the estimating sample, the model is used to predict load on those days. This process is repeated three times so that, in total, out-of-sample predictions of load are generated for the top nine system load days for each customer.

This validation process most closely aligns with what is expected of the model in the ex post and ex ante analyses. In the ex ante analysis, the model is used to simulate the reference load and load with DR under 1-in-2 and 1-in-10 weather year scenarios. The ex post analysis estimates load reductions by predicting what load would have been if an event was not called. In both of these analyses, out-of-sample predictions are generated for scenarios in which actual, unperturbed load data is not available. Therefore, out-of-sample validation using randomly selected high system load days is a logical test to determine which model is most accurate.

Figure 3-4 shows the results of the out-of-sample validation for the average of the top nine system load days for each customer. As seen in the figure, the model accurately predicts load on high system load days even if those days are not included in the estimating sample. The difference between actual and predicted load does not exceed 13% in any hour for any IOU. If SDG&E is excluded, then the difference does not exceed 4% in any hour. SDG&E only has seven customers and is therefore the hardest IOU to predict reference loads for. In contrast, PG&E had 280 ex post customers and SDG&E had 646 customers.

Figure 3-4: Actual vs. Predicted Average Load by IOU
Out-of-sample Validation for Top Nine System Load Days[7]



3.2.2 Goodness of Fit Measures

Although regressions were estimated at the individual customer level, from a program standpoint, the focus is less on how the regressions perform for individual customers than it is on how the regressions perform for the average participant and for specific customer segments. Individual customers exhibit more variation and less consistent energy use patterns than the average participant population. Likewise, the regressions are better at explaining the variation in electricity consumption and load impacts for the average customer (or average customer within a specific segment) than for individual customers. Put differently, it is more difficult to fully explain how a customer from a specific industry behaves on an hourly basis than it is to explain how the average customer in that industry behaves on an hourly basis. Because of this, we present measures of the explained variation, as described by the R-squared goodness-of-fit statistic, for the individual regressions, for specific customer segments and for the average customer overall.

Figure 3-5 shows the distribution of R-squared values from the individual customer regressions for SCE BIP customers. Roughly half of the individual customer regressions had R-squared values above 0.6, which suggests that the model predicts well for most SCE BIP customers.

[7] Note that there are two lines for each IOU in the graph, but due to the small error between estimated and actual values, it is difficult to distinguish the two lines. A table of the hourly values for each IOU is provided in Appendix A.

Figure 3-5: Distribution of R-squared Values from Individual Regressions for SCE BIP Customers

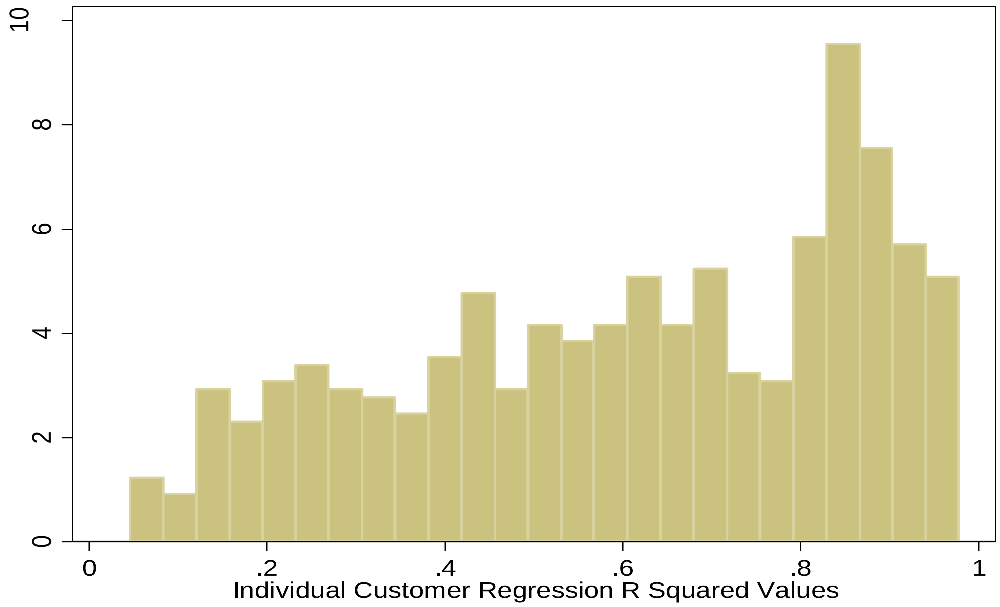
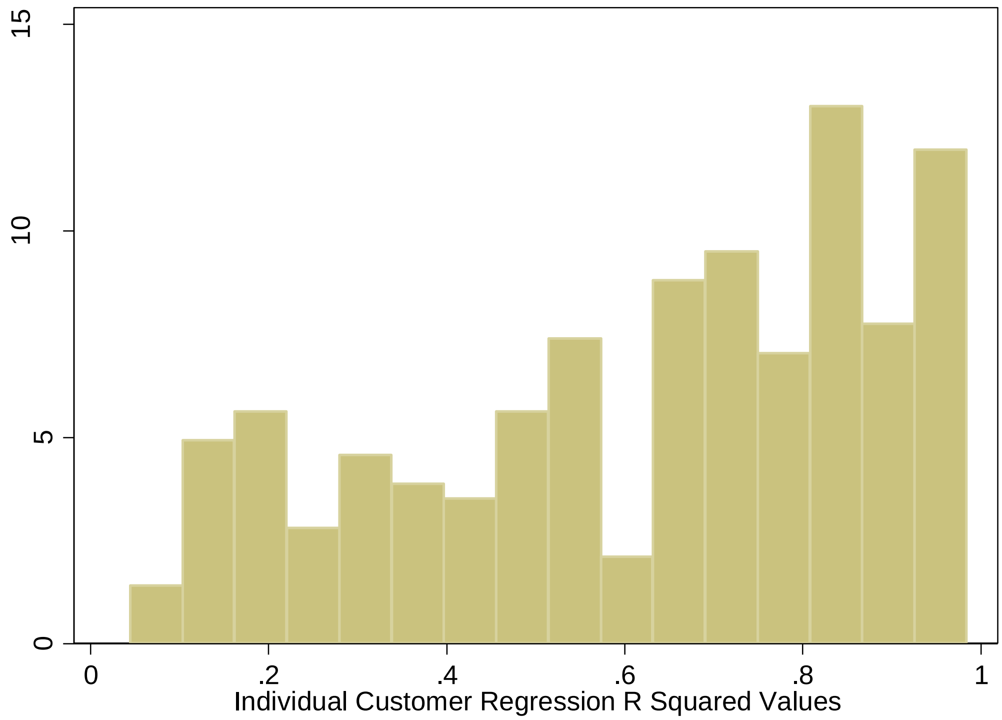


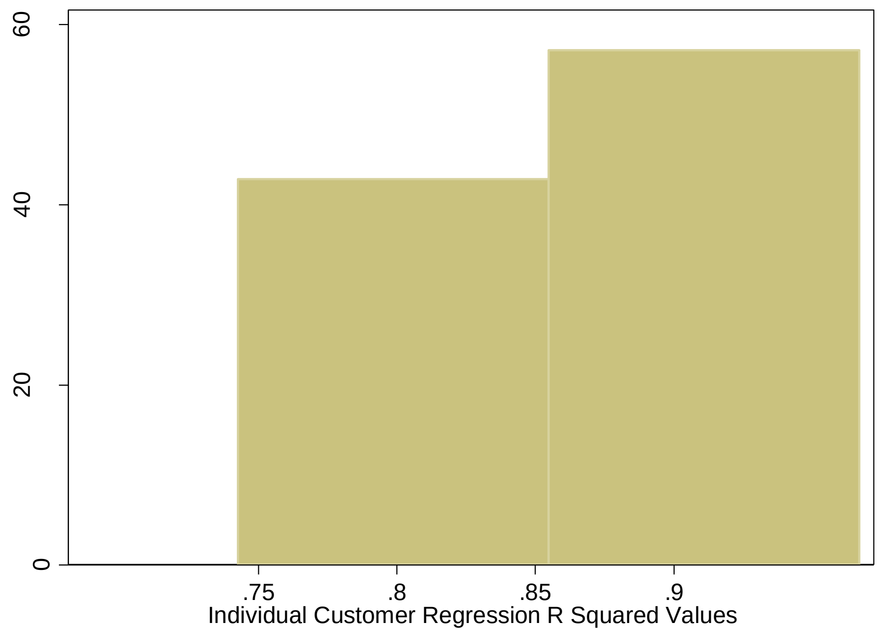
Figure 3-6 shows the distribution of R-squared values from the individual customer regressions for PG&E BIP customers. Half of the customers have R-squared values greater than 0.68. This result suggests that the model explains most of the variation in load for the majority of PG&E BIP customers.

Figure 3-6: Distribution of R-squared Values from Individual Regressions for PG&E BIP Customers



As shown in Figure 3-7, the model has relatively high R-squared values for SDG&E BIP customers. All individual customer regressions have an R-squared value above 0.5.

Figure 3-7: Distribution of R-squared Values from Individual Regressions for SDG&E BIP Customers



In order to estimate the average customer R-squared values for each industry, LCA or the program as a whole, the regression-predicted and actual electricity usage values were averaged across all customers for each date and hour. This process produced regression-predicted and actual values for the average customer, which enabled the calculation of errors for the average customer and the calculation of the R-squared value. The R-squared values for the average participant and for the average customer by segment were estimated using the following formula:[8]

$$R^2 = 1 - \frac{\sum_t (y_t - \hat{y}_t)^2}{\sum_t (y_t - \bar{y})^2}$$

[8] Technically, the R-squared value needs to be adjusted based on the number of parameters and observations from each regression. Given that the number of observations per regression was typically over 8,000, the effects of the adjustment were anticipated to be minimal. As a result, the unadjusted R-squared value is presented in order to avoid the complication of tracking the number of observations and parameters from each individual regression.

Table 3-2: Variable Descriptions

Variable	Description
y_t	Actual energy use at time t
$\hat{y}_t$	Regression-predicted energy use at time t
$\bar{y}$	Average energy use across all time periods

Table 3-3 summarizes the amount of variation explained by the regression model by industry and IOU. Across all customers, SCE and PG&E have an aggregate R-squared value of 0.62 and 0.61, respectively, which means that the model explains 62% and 61% of variation in aggregate BIP load for each IOU. As suggested by the histograms above, SDG&E BIP customers have a higher R-squared of 0.88. Retail stores have the highest aggregate R-squared value for each IOU, ranging from 0.90 for SCE to 0.95 for SDG&E. Table 3-4 summarizes R-squared values by LCA.

Table 3-3: Aggregate R-squared Values by Industry and IOU

Industry	PG&E	SCE	SDG&E
Agriculture, Mining & Construction	0.62	0.47	0.78
Manufacturing	0.56	0.55	0.78
Wholesale, Transport & Other Utilities	0.39	0.54	0.94
Retail Stores	0.92	0.90	0.95
Offices, Hotels, Finance & Services	0.79	0.72	–
Schools	0.82	0.85	–
Institutional/Government	0.79	0.79	–
All Customers	**0.62**	**0.61**	**0.88**

Table 3-4: Aggregate R-squared Values by LCA

Utility	Local Capacity Area	R-squared
SCE	LA Basin	0.62
	Outside LA Basin	0.50
	Ventura	0.57
PG&E	Greater Bay Area	0.73
	Kern	0.43
	Northern Coast	0.70
	Other/Combined LCAs	0.59
	Stockton	0.67
SDG&E	San Diego	0.88

3.3 Over/Under Performance Adjustment

In addition to estimating the reference load for the ex ante load impacts, historical event day behavior was analyzed and incorporated into PG&E and SCE ex ante results to adjust for over/under performance. Historical events were not used for SDG&E because of significant changes in the customer population in recent years. For most DR programs, the ex post impacts from previous events are applied to the ex ante estimates. For example, if a customer provided a load reduction of 500 kW on average, the typical event day on an ex ante basis would show a load reduction of roughly 500 kW for that customer. For BIP, similar *performance* relative to the FSL is expected, not similar *reductions*. Consider a BIP customer that provided an average load reduction of 500 kW with an average reference load of 800 kW during event hours. Assume that this customer had an FSL of 300 kW and with an average load reduction of 500 kW; this customer fully complied with its FSL obligations. Since this customer fully complied, it is expected that this customer would fully comply in future events. Therefore, if the predicted reference load for a typical event day is 950 kW, an impact of 650 kW would be expected (950 kW – 300 kW FSL). If we applied the same 500 kW reduction from previous events, the estimated load with DR would be 450 kW (950 kW – 500 kW), which would suggest that the customer substantially under-complied relative to its FSL of 300 kW. If a customer did not under-comply in previous events, it is not expected that it would under-comply on an ex ante basis. Therefore, the ex ante impacts are based on the estimated reference load and the FSL after adjusting for over/under performance.

Over/under performance is calculated at the industry level. Therefore, a customer in a given industry is assumed to perform similar to the recent historical performance of customers in its industry. This over/under performance adjustment in the ex ante analysis is necessary simply because there is limited (if any) event history for individual customers. Because very few actual BIP events have been called since 2006 (the exception being annual test events), we only have historical performance data for one to three BIP events for most participants. Furthermore, this analysis does not consider the performance data of customers on interruptible programs that existed prior to BIP.

The over/under performance analysis is conducted separately for each IOU in this year's evaluation. Prior to 2011, the statewide BIP evaluations pooled SCE and PG&E historical event data together in order to develop the over/under performance estimates that were incorporated into the ex ante analysis. Now that SCE and PG&E have provisions in their BIP tariffs to provide for annual test events, each IOU has its own historical event data to incorporate into the ex ante analysis. Considering that each IOU now has recent data for events under these conditions, it is possible to estimate over/under performance based on IOU-specific event data, which improves the accuracy of the ex ante results because there are differences in the design and customer mix between the two BIP programs. If SCE or PG&E call an actual system-wide BIP event in the near future, that data can be pooled with the recent test event data for each IOU because the event conditions from the customer perspective are similar. In fact, as in the recent test events that simulated peaking conditions, customers performed very well during the last actual system-wide BIP event for SCE and PG&E in 2006.

4 SCE Load Impact Analysis

This section presents 2013 ex post load impact estimates and 2014–2024 ex ante load impact estimates for SCE's BIP program. The discussion of load impacts provided below focuses on the high level – average participant and aggregate impacts. The remainder of the hourly ex post and ex ante load impact estimates that are required by the Protocols, including uncertainty-adjusted estimates, can be found in the electronic table generators provided under separate cover.

4.1 Ex Post Load Impact Estimates

SCE held a system-wide test event for 646 BIP participants on September 19 from 3 to 5 PM. Although participants are required to respond within 15 to 30 minutes for actual BIP events, advance notice was provided for the test event the Friday before the week of the event. The advance notice advised participants that there would be a test event sometime in the coming week, but the exact timing of the test event was not provided by the advance notice. SCE started providing final notification of the event at 3 PM on September 19 and customers were required to curtail load within 15 or 30 minutes of receiving notification, depending on their BIP program option.

Figure 4-1 shows the average load impact per customer in each hour on September 19. As seen, the average load drop over the two-hour event period was 1,063 kW. There were also significant load impacts after the event, as the average participant load slowly ramped back up after the event and was still roughly 10% below the reference load at the end of the day.

Figure 4-2 shows the aggregate load impact in each hour of the day. The aggregate load drop during the event period was 687 MW. This represents an 84% reduction relative to the reference load of 817 MW. From 4 to 5 PM, aggregate load fell to 130 MW and customers provided 94% of the expected load reduction given the aggregate FSL of 84.5 MW.

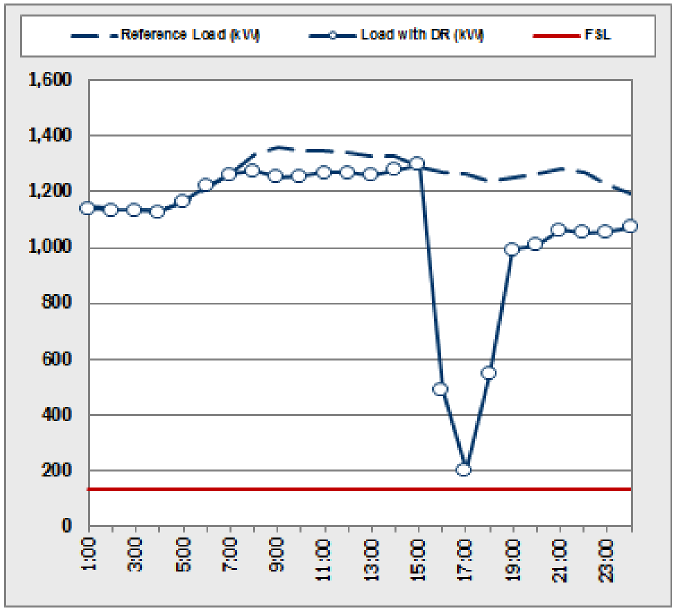
Figure 4-1: Average Ex Post Load Impact (kW) per Participant for SCE BIP Event (September 19, 2013)

TABLE 1: Menu Options

Type of Results	Average Enrolled Account
Event	Thursday, September 19, 2013
Customer Characteristic	All Customers

TABLE 2: Output

Number of Accounts	646
Average FSL (kW)	130.9



Hour Ending	Reference Load (kW)	Load with DR (kW)	Load Impact (kW)	Weighted Temp (°F)	Uncertainty-adjusted Impact - Percentiles				
					10th	30th	50th	70th	90th
1:00	1150.4	1141.4	9.1	63.7	-60.5	-19.4	9.1	37.5	78.6
2:00	1142.6	1134.4	8.2	62.7	-61.3	-20.2	8.2	36.7	77.8
3:00	1133.5	1133.0	0.5	61.7	-69.1	-28.0	0.5	29.0	70.1
4:00	1138.2	1127.5	10.7	61.1	-58.9	-17.8	10.7	39.2	80.3
5:00	1163.8	1167.3	-3.5	60.3	-73.0	-32.0	-3.5	25.0	66.0
6:00	1212.9	1218.9	-6.0	59.8	-75.5	-34.4	-6.0	22.5	63.5
7:00	1260.7	1260.6	0.1	59.9	-69.4	-28.3	0.1	28.6	69.6
8:00	1334.8	1274.0	60.8	61.1	-9.3	32.1	60.8	89.5	130.9
9:00	1358.1	1251.0	107.1	63.8	37.2	78.5	107.1	135.7	177.0
10:00	1348.2	1254.7	93.5	66.9	23.7	64.9	93.5	122.1	163.3
11:00	1346.1	1269.2	76.8	70.6	6.8	48.2	76.8	105.5	146.9
12:00	1341.8	1268.8	73.1	74.1	3.1	44.4	73.1	101.7	143.0
13:00	1326.1	1259.4	66.7	76.7	-3.1	38.2	66.7	95.3	136.6
14:00	1330.6	1278.0	52.6	78.6	-17.3	24.0	52.6	81.3	122.6
15:00	1287.9	1297.4	-9.6	79.7	-79.4	-38.2	-9.6	19.0	60.3
16:00	1272.2	486.9	785.2	79.3	715.3	756.6	785.2	813.9	855.2
17:00	1263.9	200.5	1063.3	77.6	993.2	1034.6	1063.3	1092.0	1133.4
18:00	1239.5	545.0	694.4	75.2	624.6	665.9	694.4	723.0	764.2
19:00	1249.7	990.7	259.0	71.4	189.1	230.4	259.0	287.6	328.9
20:00	1263.1	1007.8	255.3	68.2	185.4	226.7	255.3	283.9	325.2
21:00	1279.9	1062.4	217.5	66.5	147.7	188.9	217.5	246.1	287.3
22:00	1270.2	1052.2	218.0	65.3	148.1	189.4	218.0	246.6	287.9
23:00	1223.3	1057.1	166.2	64.7	96.8	137.8	166.2	194.6	235.6
0:00	1194.1	1073.7	120.4	64.5	50.9	92.0	120.4	148.9	189.9

	Reference Energy Use (kWh)	Energy Use with DR (kWh)	Change in Energy Use (kWh)	Cooling Degree Hours (Base 70)	Uncertainty-adjusted Impact - Percentiles				
					10th	30th	50th	70th	90th
Daily	30,131.7	25,812.0	4,319.7	53.2	3977.9	4179.8	4319.7	4459.5	4661.5

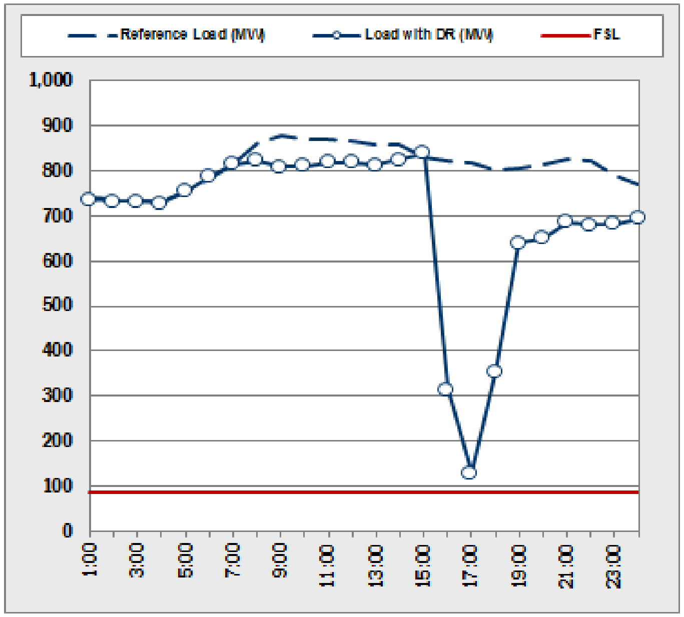
Figure 4-2: Aggregate Ex Post Load Impact (MW) for SCE BIP Event (September 19, 2013)

TABLE 1: Menu Options

Type of Results	Aggregate
Event	Thursday, September 19, 2013
Customer Characteristic	All Customers

TABLE 2: Output

Number of Accounts	646
Aggregate FSL (MW)	84.5



Hour Ending	Reference Load (MW)	Load with DR (MW)	Load Impact (MW)	Weighted Temp (°F)	Uncertainty-adjusted Impact - Percentiles				
					10th	30th	50th	70th	90th
1:00	743.2	737.3	5.9	63.7	-39.1	-12.5	5.9	24.2	50.8
2:00	738.1	732.8	5.3	62.7	-39.6	-13.1	5.3	23.7	50.3
3:00	732.2	731.9	0.3	61.7	-44.6	-18.1	0.3	18.7	45.3
4:00	735.3	728.4	6.9	61.1	-38.0	-11.5	6.9	25.3	51.9
5:00	751.8	754.1	-2.3	60.3	-47.2	-20.6	-2.3	16.1	42.7
6:00	783.5	787.4	-3.9	59.8	-48.8	-22.2	-3.9	14.5	41.0
7:00	814.4	814.4	0.1	59.9	-44.8	-18.3	0.1	18.5	45.0
8:00	862.3	823.0	39.3	61.1	-6.0	20.7	39.3	57.8	84.5
9:00	877.4	808.2	69.2	63.8	24.0	50.7	69.2	87.7	114.3
10:00	871.0	810.6	60.4	66.9	15.3	41.9	60.4	78.9	105.5
11:00	869.6	819.9	49.6	70.6	4.4	31.1	49.6	68.1	94.9
12:00	866.8	819.6	47.2	74.1	2.0	28.7	47.2	65.7	92.4
13:00	856.7	813.6	43.1	76.7	-2.0	24.7	43.1	61.6	88.2
14:00	859.6	825.6	34.0	78.6	-11.2	15.5	34.0	52.5	79.2
15:00	832.0	838.1	-6.2	79.7	-51.3	-24.6	-6.2	12.3	38.9
16:00	821.8	314.6	507.3	79.3	462.1	488.8	507.3	525.7	552.4
17:00	816.5	129.6	686.9	77.6	641.6	668.4	686.9	705.4	732.2
18:00	800.7	352.1	448.6	75.2	403.5	430.2	448.6	467.1	493.7
19:00	807.3	640.0	167.3	71.4	122.1	148.8	167.3	185.8	212.4
20:00	816.0	651.0	164.9	68.2	119.8	146.4	164.9	183.4	210.1
21:00	826.8	686.3	140.5	66.5	95.4	122.1	140.5	159.0	185.6
22:00	820.5	679.7	140.8	65.3	95.7	122.4	140.8	159.3	186.0
23:00	790.2	682.9	107.4	64.7	62.6	89.0	107.4	125.7	152.2
0:00	771.4	693.6	77.8	64.5	32.9	59.4	77.8	96.2	122.7
	Reference Energy Use (MWh)	Energy Use with DR (MWh)	Change in Energy Use (MWh)	Cooling Degree Hours (Base 70)	Uncertainty-adjusted Impact - Percentiles				
					10th	30th	50th	70th	90th
Daily	19,465.1	16,674.5	2,790.5	53.2	2569.7	2700.2	2790.5	2880.9	3011.3

Table 4-1 shows the average load impact per customer across the event period by industry group and Table 4-2 shows the aggregate impact by industry. The overall results were primarily driven by participants in the Manufacturing sector, which accounted for 58% of event participants and 67% of the aggregate load reduction. The Agriculture, Mining & Construction segment was the only other industry group to provide more than 6% of the aggregate load reduction. Although customers in this segment account for less than 9% of event participants, they produced 19% of the aggregate load reduction because Agriculture, Mining & Construction customers have the highest reference load per customer (over 2.4 MW) and largest percent load reduction (95%). Customers in the Retail Stores and Schools segments show the lowest event performance, providing less than 65% of the expected load reduction.

Table 4-1: Average Customer Load Impact by Industry for September 19, 2013 SCE Event

Industry	Number of Customers	Reference Load (kW)	Load with DR (kW)	Load Reduction (kW)	Average FSL (kW)	Performance (%)
Agriculture, Mining & Construction	56	2,480.4	134.6	2,345.8	141.1	100
Manufacturing	373	1,471.2	228.7	1,242.4	157.1	95
Wholesale, Transport & Other Utilities	69	782.6	161.1	621.6	104.8	92
Retail Stores	40	482.1	226.8	255.3	79.6	63
Offices, Hotels, Finance & Services	35	805.2	173.1	632.1	126.1	93
Schools	68	343.5	146.6	196.9	22.1	61
Institutional/Government	5	796.6	97.6	699.0	338.2	152
All Customers	**646**	**1,263.9**	**200.5**	**1,063.3**	**130.9**	**94**

Table 4-2: Aggregate Load Impact by Industry for September 19, 2013 SCE Event

Industry	Number of Customers	Reference Load (MW)	Load with DR (MW)	Load Reduction (MW)	% Load Reduction	% of Aggregate Load Reduction
Agriculture, Mining & Construction	56	138.9	7.5	131.4	95	19
Manufacturing	373	548.8	85.3	463.4	84	67
Wholesale, Transport & Other Utilities	69	54.0	11.1	42.9	79	6
Retail Stores	40	19.3	9.1	10.2	53	1
Offices, Hotels, Finance & Services	35	28.2	6.1	22.1	79	3
Schools	68	23.4	10.0	13.4	57	2
Institutional/Government	5	4.0	0.5	3.5	88	1
All Customers	**646**	**816.5**	**129.6**	**686.9**	**84**	**100**

Tables 4-3 and 4-4 show the breakdown of load impacts by LCA. Although customers in the LA Basin LCA had the lowest average load reduction per customer (781.7 kW), this LCA accounted for 72% of the aggregate load reduction because 551 of 646 event participants were located there. Customers in the Outside LA Basin LCA provided the largest average load reduction per participant (3.4 MW) and highest percent load reduction (86%). As a result, this area accounted for 13% of the aggregate load reduction even though only 3.6% of event participants were in that LCA.

Table 4-3: Average Customer Load Impact by Local Capacity Area for September 19, 2013 SCE Event

Local Capacity Area	Number of Customers	Reference Load (kW)	Load with DR (kW)	Load Reduction (kW)	Average FSL (kW)	Performance (%)
LA Basin	551	1,108.3	205.5	902.8	133.1	93
Outside LA Basin	23	4,042.3	182.3	3,860.0	136.0	99
Ventura	72	1,566.6	168.4	1,398.2	112.1	96
All Customers	**646**	**1,263.9**	**200.5**	**1,063.3**	**130.9**	**94**

Table 4-4: Aggregate Load Impact by Local Capacity Area for September 19, 2013 SCE Event

Local Capacity Area	Number of Customers	Reference Load (MW)	Load with DR (MW)	Load Reduction (MW)	% Load Reduction	% of Aggregate Load Reduction
LA Basin	551	610.7	113.2	497.5	81	72
Outside LA Basin	23	93.0	4.2	88.8	95	13
Ventura	72	112.8	12.1	100.7	89	15
All Customers	**646**	**816.5**	**129.6**	**686.9**	**84**	**100**

Due to the closure of the San Onofre Nuclear Generating Station (SONGS), load impacts have been estimated for the transmission planning areas that are most affected by the generation outage, South Orange County and South of Lugo. Figure 4-3 and 4-4 shows the aggregate load impact for each hour of the event day in these areas. The aggregate hourly impact from 4 to 5 PM was 22 MW for the 34 South Orange County BIP participants and 103 MW for the 179 South of Lugo BIP participants. This represents a 71% and 72% reduction, respectively. As shown by the figures and aggregate load impact estimates, BIP is a substantial resource in both of these supply-constrained regions.

Figure 4-3: Average Ex Post Load Impact (kW) per Participant in South Orange County for SCE BIP Event (September 19, 2013)

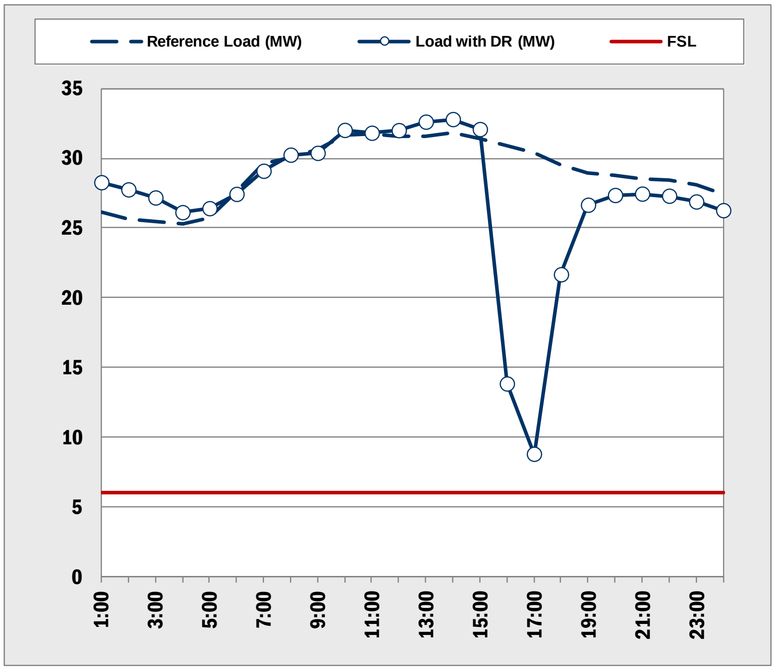
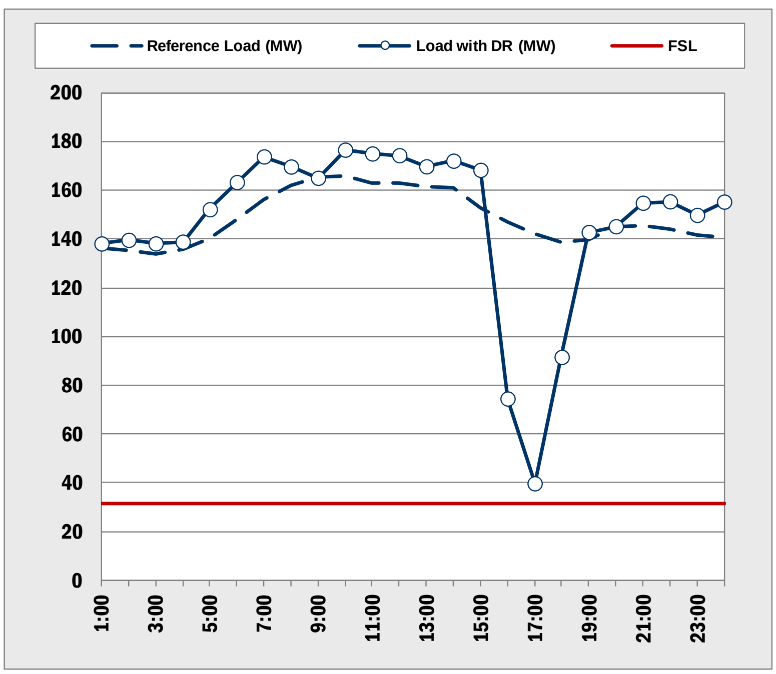


Figure 4-4: Average Ex Post Load Impact (kW) per Participant in South of Lugo for SCE BIP Event (September 19, 2013)



4.2 Over/Under Performance Analysis

For SCE’s over/under performance analysis, data for the 2011, 2012 and 2013 SCE test events was used. Table 4-5 shows the results of the over/under performance analysis by industry for SCE BIP customers.

A value over 100% means that customers in that industry over performed whereas a value under 100% means that customers in that industry under performed. For all industries combined, customers provided 93% of the expected load reduction given their FSL during the events. This performance level differs from the reported performance in Table 4-1 and Table 4-3 because of two reasons. Firstly, it incorporates the performance for past year's events, not just the September 19 event. Secondly, it does not use the first hour of the BIP event. SCE starts providing final notification in the first event hour and customers are required to curtail load within 15 or 30 minutes of receiving notification, depending on their BIP program option. Therefore, curtailment begins at earliest 15 minutes into the hour, and at the latest, 30 minutes into the hour. Therefore, this hour is not used to determine event impacts but is instead used to determine load shapes in the hour preceding the event. After identifying the specific intervals for which each individual customer was required to respond, participants achieved 93% performance overall.

Performance varies substantially by industry. Customers in the Agriculture, Mining & Construction and Manufacturing segments underperform slightly during the events, which drives much of the overall result for all customers. Retail Stores and Schools generally underperform, providing less than 75% of the expected load reduction.

Although the main purpose of this exercise was to determine over/under performance by industry during the event hours, it also provided information on electric load during pre-event and post-event hours, which was incorporated into the ex ante estimates. The hour before the event reflects the load reduction that occurs as customers are receiving event notifications from SCE. After the event, aggregate load does not return to the level of the reference load until the end of the day or later. This means that there are substantial load impacts after the event ends.

Table 4-5: SCE BIP Over/Under Performance Percentages by Industry and Event Hour 2011-2013 SCE System wide BIP Events

Industry	% Over/Under Performance			
	Hour Before Event	First Hour of Event	Last Hour of Event	Hour After Event
Agriculture, Mining & Construction	47%	99%	99%	66%
Manufacturing	45%	94%	94%	63%
Wholesale, Transport & Other Utilities	42%	91%	91%	46%
Retail Stores	28%	65%	65%	37%
Offices, Hotels, Finance & Services	39%	83%	83%	50%
Schools	33%	71%	71%	55%
Institutional/Government	36%	124%	124%	75%
All Customers	**44%**	**93%**	**93%**	**61%**

4.3 Ex Ante Load Impact Estimates

SCE projects that BIP enrollment will decline to 610 customers by the end of 2014, where it will remain constant till 2024. Figures 4-5 and 4-6 show the reference load and estimated load with DR for the average customer on a typical event day based on 1-in-2 and 1-in-10 year weather conditions for the year 2016. Impacts are reported for 2016 instead of 2014 because it is the year in which BIP load growth reaches a steady state through 2024. For a 1-in-2 typical event day, the estimated load impact for the average participant is 1,065.2 kW from 1 to 6 PM. This represents an 83.3% impact relative to the average reference load of 1,278.2 kW. Based on 1-in-10 year weather conditions, the load impact pattern over the event period is nearly identical to that of a 1-in-2 weather year because BIP customer usage is not sensitive to temperature.

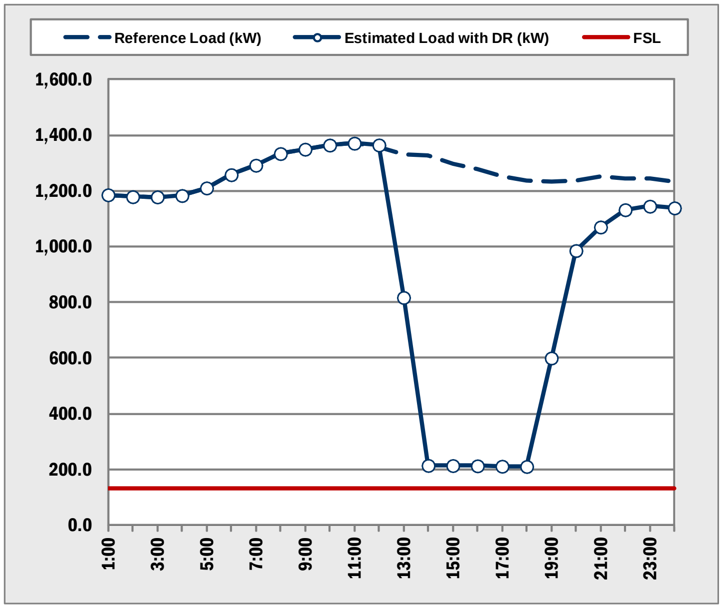
Figure 4-5: SCE BIP Average Load Impact (kW) per Customer in 2016 for a Typical Event Day Based on 1-in-2 Year Weather Conditions

TABLE 1: Menu options

Type of Results	Average Enrolled Account
Weather Year	1-in-2
Forecast Year	2016-2024
Day Type	Typical Event Day
Customer Characteristic	All Customers

TABLE 2: Output

Number of Accounts	610
Average FSL (kW)	132.9
Proxy Date	-
Average Load Impact (kW) (1-6pm)	1,065.2
% Load Impact (1-6pm)	83.3%



Hour Ending	Reference Load (kW)	Estimated Load with DR (kW)	Load Impact (kW)	Weighted Temp (F)	Uncertainty Adjusted Impact - Percentiles 10th	30th	50th	70th	90th
1:00	1185.9	1185.9	0.0	69.2	-73.2	-30.0	0.0	30.0	73.2
2:00	1179.1	1179.1	0.0	68.2	-73.2	-29.9	0.0	29.9	73.2
3:00	1178.4	1178.4	0.0	66.9	-73.2	-30.0	0.0	30.0	73.2
4:00	1183.4	1183.4	0.0	66.3	-73.2	-30.0	0.0	30.0	73.2
5:00	1210.5	1210.5	0.0	65.5	-73.2	-30.0	0.0	30.0	73.2
6:00	1258.1	1258.1	0.0	65.0	-73.3	-30.0	0.0	30.0	73.3
7:00	1292.0	1292.0	0.0	65.5	-73.2	-30.0	0.0	30.0	73.2
8:00	1333.8	1333.8	0.0	68.9	-73.6	-30.1	0.0	30.1	73.6
9:00	1349.5	1349.5	0.0	74.4	-73.5	-30.1	0.0	30.1	73.5
10:00	1364.3	1364.3	0.0	79.6	-73.6	-30.1	0.0	30.1	73.6
11:00	1370.5	1371.1	-0.6	83.9	-74.1	-30.7	-0.6	29.5	73.0
12:00	1357.4	1364.7	-7.3	87.1	-80.7	-37.3	-7.3	22.8	66.2
13:00	1331.5	817.5	514.0	89.5	440.6	483.9	514.0	544.1	587.5
14:00	1325.8	214.6	1111.2	91.2	1037.8	1081.1	1111.2	1141.2	1184.6
15:00	1298.1	214.3	1083.9	91.8	1010.6	1053.9	1083.9	1113.9	1157.2
16:00	1278.9	213.3	1065.6	91.9	992.2	1035.6	1065.6	1095.7	1139.0
17:00	1252.3	211.9	1040.3	90.8	967.0	1010.3	1040.3	1070.4	1113.7
18:00	1235.8	211.0	1024.8	88.6	951.4	994.8	1024.8	1054.9	1098.2
19:00	1231.8	600.2	631.6	85.4	558.2	601.5	631.6	661.6	704.9
20:00	1235.5	985.8	249.8	81.7	176.4	219.7	249.8	279.8	323.1
21:00	1251.2	1070.4	180.8	77.6	107.4	150.7	180.8	210.8	254.2
22:00	1243.4	1132.3	111.1	75.1	37.6	81.0	111.1	141.1	184.5
23:00	1244.0	1145.0	99.0	73.2	25.7	69.0	99.0	129.0	172.3
0:00	1231.2	1138.9	92.3	71.4	19.1	62.3	92.3	122.3	165.5
	Reference Energy Use (kWh)	Energy Use with DR (kWh)	Change in Energy Use (kWh)	Cooling Degree Hours (Base 70)	Uncertainty Adjusted Impact - Percentiles 10th	30th	50th	70th	90th
Daily	30,422.3	23,225.9	7,196.4	213.1	6837.0	7049.3	7196.4	7343.5	7555.8

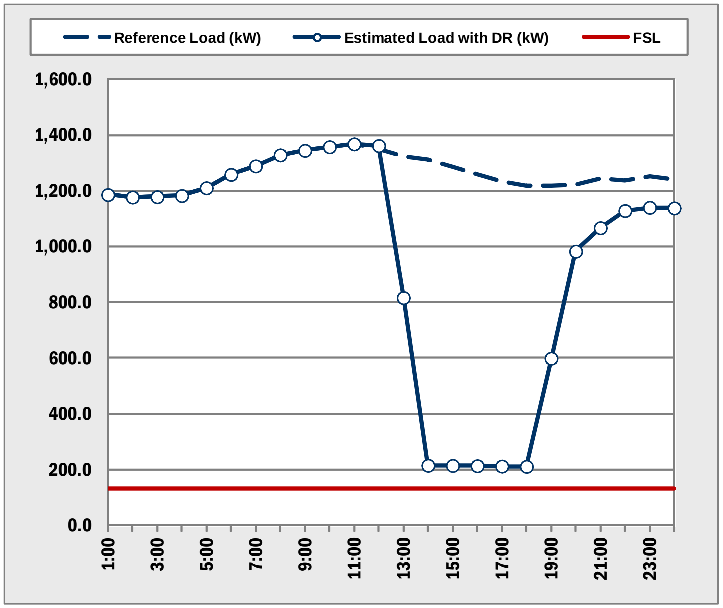
Figure 4-6: SCE BIP Average Load Impact (kW) per Customer in 2016 for a Typical Event Day Based on 1-in-10 Year Weather Conditions

TABLE 1: Menu options

Type of Results	Average Enrolled Account
Weather Year	1-in-10
Forecast Year	2016-2024
Day Type	Typical Event Day
Customer Characteristic	All Customers

TABLE 2: Output

Number of Accounts	610
Average FSL (kW)	132.9
Proxy Date	-
Average Load Impact (kW) (1-6pm)	1,047.2
% Load Impact (1-6pm)	83.0%



Hour Ending	Reference Load (kW)	Estimated Load with DR (kW)	Load Impact (kW)	Weighted Temp (F)	Uncertainty Adjusted Impact - Percentiles				
					10th	30th	50th	70th	90th
1:00	1186.3	1186.3	0.0	76.1	-73.7	-30.1	0.0	30.1	73.7
2:00	1177.4	1177.4	0.0	74.6	-73.6	-30.1	0.0	30.1	73.6
3:00	1178.7	1178.7	0.0	73.7	-73.7	-30.1	0.0	30.1	73.7
4:00	1182.9	1182.9	0.0	72.9	-73.6	-30.1	0.0	30.1	73.6
5:00	1210.9	1210.9	0.0	72.3	-73.7	-30.1	0.0	30.1	73.7
6:00	1258.6	1258.6	0.0	71.8	-73.7	-30.2	0.0	30.2	73.7
7:00	1289.2	1289.2	0.0	72.0	-73.7	-30.1	0.0	30.1	73.7
8:00	1328.7	1328.7	0.0	74.7	-74.0	-30.3	0.0	30.3	74.0
9:00	1344.8	1344.8	0.0	79.0	-73.8	-30.2	0.0	30.2	73.8
10:00	1357.9	1357.9	0.0	83.0	-73.9	-30.2	0.0	30.2	73.9
11:00	1367.5	1368.1	-0.6	86.1	-74.5	-30.9	-0.6	29.6	73.3
12:00	1351.0	1362.0	-11.0	88.5	-84.7	-41.2	-11.0	19.2	62.7
13:00	1322.7	817.0	505.7	90.7	432.0	475.6	505.7	535.9	579.5
14:00	1311.7	215.7	1096.0	92.3	1022.4	1065.9	1096.0	1126.2	1169.7
15:00	1284.7	215.1	1069.6	93.1	996.1	1039.6	1069.6	1099.7	1143.1
16:00	1260.3	214.2	1046.1	92.7	972.5	1016.0	1046.1	1076.3	1119.7
17:00	1232.3	212.8	1019.4	91.4	945.8	989.3	1019.4	1049.6	1093.1
18:00	1216.6	211.8	1004.8	89.2	931.2	974.7	1004.8	1035.0	1078.5
19:00	1217.4	599.6	617.8	85.9	544.2	587.7	617.8	647.9	691.4
20:00	1221.7	983.5	238.2	81.8	164.6	208.1	238.2	268.4	311.9
21:00	1242.8	1067.5	175.3	78.2	101.7	145.2	175.3	205.5	249.0
22:00	1236.6	1129.0	107.6	76.1	33.8	77.4	107.6	137.7	181.3
23:00	1250.0	1140.6	109.4	74.3	35.6	79.2	109.4	139.6	183.2
0:00	1238.7	1138.5	100.2	73.2	26.5	70.1	100.2	130.4	173.9
	Reference Energy Use (kWh)	Energy Use with DR (kWh)	Change in Energy Use (kWh)	Cooling Degree Hours (Base 70)	Uncertainty Adjusted Impact - Percentiles				
					10th	30th	50th	70th	90th
Daily	30,269.2	23,190.4	7,078.8	263.4	6717.7	6931.0	7078.8	7226.5	7439.8

Table 4-6 shows the aggregate on-peak ex ante load impact estimates for each day type by weather year and forecast year. In accordance with the revised resource adequacy hours, the peak period is defined as 1 to 6 PM for the typical event day and the April through October monthly peak days and 4 to 9 PM for the November through March monthly peak days. The change in peak period timing does not affect SCE BIP customers substantially because they have a relatively flat load shape. Load impacts are lower during the November through March time period because usage is relatively low during those months, not because of the change in peak period timing. Aggregate load impacts for all forecast years are lowest for the December monthly peak day, which is likely due to the holiday season when many manufacturing facilities operate at less than full capacity.

Once load growth reaches a steady state in the 2015 through 2024 time period, the program is expected to be capable of delivering up to 657.6 MW, which occurs during the June monthly peak under 1-in-2 weather conditions.

Table 4-6: SCE BIP Aggregate On-Peak Load Impacts (MW) for Each Day Type by Weather Year and Forecast Year

Weather Year	Day Type	Peak Period	2014	2015	2016-2024
1-in-2	Typical Event Day	1 to 6 PM	656.6	649.7	649.7
	January Peak	4 to 9 PM	558.8	554.4	554.4
	February Peak	4 to 9 PM	588.3	584.6	584.6
	March Peak	4 to 9 PM	583.6	580.7	580.7
	April Peak	1 to 6 PM	618.0	614.9	614.9
	May Peak	1 to 6 PM	638.8	634.7	634.7
	June Peak	1 to 6 PM	662.8	657.6	657.6
	July Peak	1 to 6 PM	652.6	646.6	646.6
	August Peak	1 to 6 PM	647.7	640.9	640.9
	September Peak	1 to 6 PM	663.2	655.3	655.3
	October Peak	1 to 6 PM	612.8	604.8	604.8
	November Peak	4 to 9 PM	595.2	586.7	586.7
	December Peak	4 to 9 PM	529.9	530.6	530.6
1-in-10	Typical Event Day	1 to 6 PM	645.5	638.8	638.8
	January Peak	4 to 9 PM	548.2	544.0	544.0
	February Peak	4 to 9 PM	578.6	575.0	575.0
	March Peak	4 to 9 PM	589.4	586.5	586.5
	April Peak	1 to 6 PM	605.6	602.6	602.6
	May Peak	1 to 6 PM	629.8	625.8	625.8

Weather Year	Day Type	Peak Period	2014	2015	2016-2024
	June Peak	1 to 6 PM	650.6	645.5	645.5
	July Peak	1 to 6 PM	639.4	633.5	633.5
	August Peak	1 to 6 PM	637.3	630.7	630.7
	September Peak	1 to 6 PM	659.4	651.6	651.6
	October Peak	1 to 6 PM	617.0	608.9	608.9
	November Peak	4 to 9 PM	589.5	580.9	580.9
	December Peak	4 to 9 PM	522.1	522.9	522.9

Table 4-7 provides the 2014 and 2016–2024 average and aggregate load impact estimates by LCA for a typical event day under 1-in-2 weather conditions. Throughout the forecast period, aggregate load impacts are primarily concentrated in SCE's LA Basin, accounting for roughly 71.5% of aggregate impacts. However, this LCA accounts for roughly 86% of the participant population. On the other hand, the Outside LCA accounts for about 3% of the population but is responsible for 14% of aggregate load reduction.

Table 4-7: 2014 and 2016–2024 Average and Aggregate Load Impacts by LCA Typical Event Day under 1-in-2 Weather Conditions, 1 PM to 6 PM

Forecast Year	LCA	Number of Customers	Reference Load (kW)	Load with DR (kW)	Avg. Load Impact (kW)	Aggregate Load Impact (MW)	% of Total Aggregate Load Impact
2014	LA Basin	534	1,085.4	205.9	879.5	469.6	72
	Outside	21	4,606.3	384.6	4,221.8	88.7	14
	Ventura	67	1,693.2	209.3	1,483.9	99.4	15
	All Customers	**621**	**1,269.7**	**212.3**	**1,057.4**	**656.6**	**100**
2016-2024	LA Basin	524	1,092.2	206.5	885.6	464.1	71
	Outside	21	4,635.0	386.2	4,248.8	89.2	14
	Ventura	66	1,709.2	210.0	1,499.2	98.9	15
	All Customers	**610**	**1,278.2**	**213.0**	**1,065.2**	**649.7**	**100**

4.4 Comparison of Ex Post to Ex Ante Estimates

BIP Ex ante load impact estimates developed by combining three key pieces of information. The complete estimation process is described with more detail in Section 3, but it can be summarized as follows:

A. Estimate reference load for continuing or new BIP participants under 1-in-2 and 1-in-10 weather conditions for 12 day types (typical peak days for each month of the year). These estimates of reference load under varying weather and month conditions are obtained by using the models developed in the ex post analysis.

B. Obtain the FSLs for all continuing or new BIP participants that will be in effect in 2014. These FSLs may or may not be the same as those in effect during the 2013 test events for continuing customers, since customers have the opportunity to change their FSLs in November every year.

C. Apply historic over/under-performance factors to FSLs. Over/under-performance is estimated for each industry for each IOU. Load impact is derived by deducting the expected performance (the kW level customers are expected to reach during event hours, obtained in Step B above) from the estimated reference load obtained in Step A above.

Before comparing the 2013 ex post load impacts to 2014 ex ante estimates, it is helpful to review ex post load impacts for 2012 and 2013 side by side. Table 4-8 presents three years of BIP ex post load impact estimates for SCE. Since 2011, there has been a downward trend in BIP enrollment at SCE; in 2011 there were 661 BIP participants and by 2013 there were 646. While the number of enrolled customers has decreased, the reference load of the participating customers has increased from 1,126 kW to 1,264 kW. This 12% increase in reference load more than compensates for the 2.3% reduction in enrolled customers since 2011. Load reduction has also significantly increased, which is both a function of the increased reference load but also of increased performance relative to the FSL; performance is up from 92% in 2011 to 94% in 2013. In total, these changes have produced 15% more MW of load reduction in 2013 relative to 2011. It is important to keep in mind that when comparing ex post load impact estimates across three years of BIP program history, there is only one system-wide event each year that can be used to form the basis of conclusions.

Table 4-8: Multiyear Comparison of SCE BIP Ex Post Load Impacts

Event Date	Number of Customers	Reference Load (kW)	Load Reduction (kW)	Aggregate Load Reduction (MW)	Load Reduction (%)	Performance (%)	Total CDH
9/19/2013	646	1,263.9	1,063.3	686.9	84	94	53
9/26/2012	667	1,154.9	947.0	631.6	82	93	58
9/21/2011	661	1,125.9	901.2	595.7	80	92	60

Table 4-9 shows the ex post and ex ante load impact estimates produced in this 2013 load impact evaluation side by side. Modest change is projected for load impacts in July 2014 under 1-in-2 or 1-in-10 weather conditions relative to 2013 ex post load impacts. First , fewer customers are presently projected to be subject to BIP events or test events in 2014 – 621 versus 646 in 2013. These customers are projected to have slightly lower reference load than the 2013 BIP population, about 0.5% to 2% less, depending on the assumptions used to represent 1-in-2 and 1-in-10 weather conditions. The FSL for the average customer will also be a little higher in 2014 – 133 kW compared to 131 in 2013. This change in FSL is a combination of changes in FSLs that continuing customers have elected and of the fact that some customers who participated in 2013 are no longer enrolled in BIP for 2014. FSL performance is also projected to fall in 2014 because some customers have left and the average FSL performance of the remaining customers is slightly lower. In total, these small changes result in a 5-7% reduction in MWs, depending on the weather assumption. Note that the value for cooling degree hours (CDH) is only 53 for the 2013 ex post load impact estimate because the estimate is for only one hour of test event duration. The ex ante estimates assume five hours of event duration, from 1 to 6 PM, in July.

Table 4-9: Ex Ante Estimates vs. Ex Post Estimates from the 2013 Evaluation

Result Type	Weather Year / Date	Number of Customers	FSL (kW)	Reference Load (kW)	Performance (%)	Agg. Load Reduction (MW)	Total CDH
Ex Ante (2014)	1-in-2, July Monthly Peak	621	133.0	1,257.8	93	653	211
Ex Ante (2014)	1-in-10, July Monthly Peak	621	133.0	1,237.8	93	639	271
Ex Post (2013)	9/19/2013	646	130.9	1,263.9	94	687	53

Figure 4-7 and Table 4-10 present the differences between ex ante load impact estimates from the 2013 and 2012 BIP load impact evaluations. The 2012 estimates show the effects of load and customer growth assumption in the earliest year of the forecast but is generally 14 MW or about 2% lower than the 2013 ex ante estimate. Although forecasted enrollment is lower for the 2013 ex ante estimates, this negative effect on aggregate load reduction is countered by an increase in per customer load reduction, driven by higher average reference loads. There is a 79 kW increase, or equivalently an 8% increase, in per customer load reduction from 2012 to 2013, translating to 641 MWs forecasted to be delivered by 610 customers on an August system peak day in 2023, compared to 627.0 MW forecasted for the same scenario in the 2012 load impact evaluation. This represents an overall increase of 2.2% in MWs forecasted to be delivered in August 2023 from the 2012 evaluation to the 2013 evaluation.

Figure 4-7: Ex Ante Aggregate Impacts for a 1-in-2 Weather Year, August Monthly Peak Day by Evaluation Year and Forecast Year

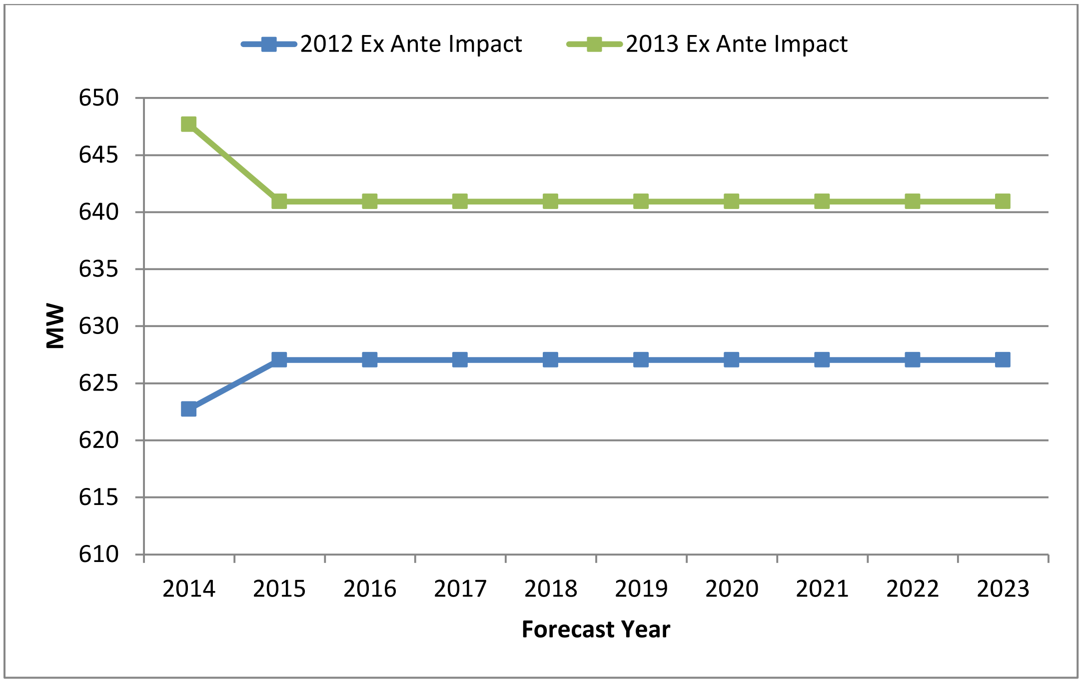


Table 4-10: Ex Ante 1-in-2 Weather Year, August Monthly Peak Day Estimations for Forecast Year 2023 by Evaluation Year

Evaluation Year	Number of Customers	FSL (kW)	Reference Load (kW)	Performance (%)	Agg. Load Reduction (MW)
2013	610	132.9	1,265.0	93	640.9
2012	647	130.2	1,177.5	93	627.0

5 PG&E Load Impact Analysis

This section presents 2013 ex post load impact estimates and 2014–2024 ex ante load impact estimates for the PG&E BIP. The discussion of load impacts provided below focuses on high-level average and aggregate impacts. The remainder of the hourly ex post and ex ante load impact estimates that are required by the CPUC Load Impact Protocols, including uncertainty-adjusted estimates, can be found in the electronic table generators provided under separate cover.

5.1 Ex Post Load Impact Estimates

The ex post load impact estimates presented in this section are for PG&E's system-wide BIP test event that occurred on July 2 from 3 to 7 PM in addition to the limited retest event that occurred on August 27 from 2 to 6 PM. The July test event included all 280 customers that were enrolled in BIP at that time. The retest event that occurred on August 27 only included 63 customers. This group of customers is a subset of those customers that did not meet their FSL commitment during the first system-wide event.

Figure 5-1 shows the average load impact per customer in each hour of the system-wide event day. The average load drop over the four-hour event period was 771.6 kW. In the hour prior to the event, the average load reduction equaled 189.5 kW, and in the first hour after the event, load was still 420.5 kW below the reference load.

Figure 5-2 shows the aggregate load impact in each hour of the system-wide event day. The aggregate load drop during the event period was 216.0 MW. This represents a 74% reduction relative to the reference load of 290.7 MW. On aggregate, customers provided around 95% of the expected load reduction given the aggregate FSL of 63.5 MW.

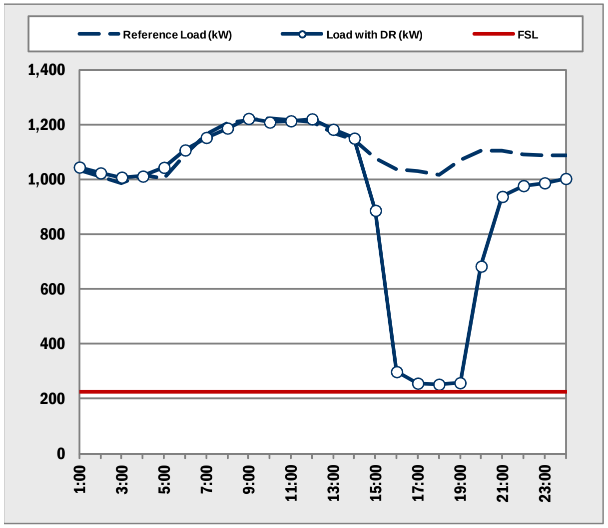
Figure 5-1: Average Ex Post Load Impact (kW) per Participant for PG&E BIP System-wide Event (July 2, 2013)

TABLE 1: Menu Options

Type of Results	Average Enrolled Account
Event	Tuesday, July 02, 2013
Customer Characteristic	All Customers

TABLE 2: Output

Number of Accounts	280
Average FSL (kW)	226.7



Hour Ending	Reference Load (kW)	Load with DR (kW)	Load Impact (kW)	Weighted Temp. (°F)	Uncertainty-adjusted Impact - Percentiles 10th	30th	50th	70th	90th
1:00	1034.4	1044.8	-10.4	78.0	-55.8	-29.0	-10.4	8.1	34.9
2:00	1008.5	1023.4	-14.9	76.6	-60.5	-33.6	-14.9	3.7	30.7
3:00	986.0	1008.0	-22.0	75.6	-67.5	-40.6	-22.0	-3.4	23.5
4:00	1015.2	1011.8	3.4	74.6	-47.7	-17.5	3.4	24.3	54.5
5:00	1004.1	1043.7	-39.6	73.6	-85.8	-58.6	-39.6	-20.7	6.6
6:00	1091.9	1107.0	-15.1	72.9	-61.5	-34.1	-15.1	3.8	31.2
7:00	1165.7	1152.7	13.0	72.6	-34.1	-6.3	13.0	32.3	60.2
8:00	1206.5	1187.1	19.4	75.1	-27.3	0.3	19.4	38.5	66.1
9:00	1215.8	1222.0	-6.2	78.9	-51.7	-24.8	-6.2	12.4	39.3
10:00	1222.3	1208.8	13.5	83.4	-32.0	-5.1	13.5	32.1	59.0
11:00	1214.8	1213.4	1.4	86.8	-43.3	-16.9	1.4	19.7	46.2
12:00	1208.0	1220.4	-12.4	89.7	-56.9	-30.6	-12.4	5.8	32.1
13:00	1170.4	1182.3	-12.0	92.7	-56.3	-30.1	-12.0	6.2	32.4
14:00	1144.9	1150.3	-5.4	94.9	-49.4	-23.4	-5.4	12.6	38.6
15:00	1076.4	886.9	189.5	96.2	145.8	171.6	189.5	207.4	233.2
16:00	1035.5	298.9	736.6	96.6	693.0	718.8	736.6	754.4	780.2
17:00	1029.0	256.7	772.3	95.4	728.7	754.5	772.3	790.1	815.9
18:00	1017.8	252.8	764.9	93.5	721.3	747.0	764.9	782.8	808.5
19:00	1071.0	258.5	812.5	90.1	768.5	794.5	812.5	830.5	856.4
20:00	1104.0	683.5	420.5	85.7	376.6	402.5	420.5	438.4	464.3
21:00	1105.7	937.7	168.1	82.0	124.1	150.1	168.1	186.1	212.0
22:00	1092.0	977.1	114.9	78.6	70.7	96.8	114.9	133.0	159.1
23:00	1087.2	987.3	99.9	76.6	55.7	81.8	99.9	118.0	144.1
0:00	1087.4	1003.1	84.4	74.6	40.1	66.2	84.4	102.5	128.7
	Reference Energy Use (kWh)	Energy Use with DR (kWh)	Change in Energy Use (kWh)	Cooling Degree Hours (Base 70)	Uncertainty-adjusted Impact - Percentiles 10th	30th	50th	70th	90th
Daily	26,394.2	22,318.1	4,076.1	314.6	3855.2	3985.7	4076.1	4166.5	4297.0

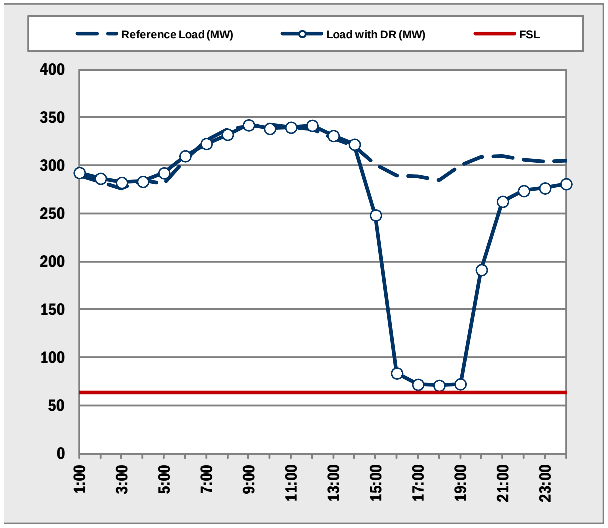
Figure 5-2: Aggregate Load Impact (MW) for PG&E BIP System-wide Event (July 2, 2013)

TABLE 1: Menu Options

Type of Results	Aggregate
Event	Tuesday, July 02, 2013
Customer Characteristic	All Customers

TABLE 2: Output

Number of Accounts	280
Aggregate FSL (MW)	63.5



Hour Ending	Reference Load (MW)	Load with DR (MW)	Load Impact (MW)	Weighted Temp. (°F)	Uncertainty-adjusted Impact - Percentiles 10th	30th	50th	70th	90th
1:00	289.6	292.5	-2.9	78.0	-15.6	-8.1	-2.9	2.3	9.8
2:00	282.4	286.6	-4.2	76.6	-16.9	-9.4	-4.2	1.0	8.6
3:00	276.1	282.2	-6.2	75.6	-18.9	-11.4	-6.2	-1.0	6.6
4:00	284.3	283.3	1.0	74.6	-13.4	-4.9	1.0	6.8	15.3
5:00	281.1	292.2	-11.1	73.6	-24.0	-16.4	-11.1	-5.8	1.8
6:00	305.7	310.0	-4.2	72.9	-17.2	-9.6	-4.2	1.1	8.7
7:00	326.4	322.8	3.7	72.6	-9.6	-1.8	3.7	9.1	16.9
8:00	337.8	332.4	5.4	75.1	-7.6	0.1	5.4	10.8	18.5
9:00	340.4	342.2	-1.7	78.9	-14.5	-6.9	-1.7	3.5	11.0
10:00	342.2	338.5	3.8	83.4	-9.0	-1.4	3.8	9.0	16.5
11:00	340.2	339.8	0.4	86.8	-12.1	-4.7	0.4	5.5	12.9
12:00	338.2	341.7	-3.5	89.7	-15.9	-8.6	-3.5	1.6	9.0
13:00	327.7	331.1	-3.3	92.7	-15.8	-8.4	-3.3	1.7	9.1
14:00	320.6	322.1	-1.5	94.9	-13.8	-6.6	-1.5	3.5	10.8
15:00	301.4	248.3	53.1	96.2	40.8	48.1	53.1	58.1	65.3
16:00	289.9	83.7	206.3	96.6	194.0	201.3	206.3	211.2	218.5
17:00	288.1	71.9	216.2	95.4	204.0	211.3	216.2	221.2	228.4
18:00	285.0	70.8	214.2	93.5	202.0	209.2	214.2	219.2	226.4
19:00	299.9	72.4	227.5	90.1	215.2	222.5	227.5	232.5	239.8
20:00	309.1	191.4	117.7	85.7	105.5	112.7	117.7	122.8	130.0
21:00	309.6	262.6	47.1	82.0	34.7	42.0	47.1	52.1	59.4
22:00	305.8	273.6	32.2	78.6	19.8	27.1	32.2	37.2	44.5
23:00	304.4	276.4	28.0	76.6	15.6	22.9	28.0	33.0	40.3
0:00	304.5	280.9	23.6	74.6	11.2	18.5	23.6	28.7	36.0
	Reference Energy Use (MWh)	Energy Use with DR (MWh)	Change in Energy Use (MWh)	Cooling Degree Hours (Base 70)	Uncertainty-adjusted Impact - Percentiles 10th	30th	50th	70th	90th
Daily	7,390.4	6,249.1	1,141.3	314.6	1079.5	1116.0	1141.3	1166.6	1203.2

Table 5-1 shows the average load impact per customer across the event period by industry group and Table 5-2 shows the aggregate impact by industry. Among the seven industry groups included in Table 5-1, only the Agriculture, Mining & Construction segment performed at 100% or above, meaning they reduced load at or below their FSL. Notably low-performing segments were Retail Stores with 13% performance and Institutional/Government with 53%. Performance for Schools is not cited for the 2013 system-wide test event. On the day of the test event, schools enrolled in BIP were part of an aggregator's portfolio and were evidently not in session and were operating with electric load well below their FSL. The schools did not have to reduce load at all to meet their FSL on this day. It should be noted that PG&E does not have control over which individual accounts aggregators dispatch for BIP events. In terms of actual kW of load reduction, the Manufacturing segment performs the best out of all the industries with an average load reduction of 1,413 kW per customer and an aggregate load reduction of 136 MW. Manufacturing also accounts for 63% of the total aggregate load reduction.

Table 5-1: Average Customer Load Impact by Industry for July 2, 2013 PG&E Event

Industry	Number of Customers	Reference Load (kW)	Load with DR (kW)	Load Reduction (kW)	Average FSL (kW)	Performance (%)
Agriculture, Mining & Construction	44	952.8	285.6	667.2	308.7	104
Manufacturing	96	1,669.8	256.5	1,413.3	200.1	96
Wholesale, Transport & Other Utilities	55	793.9	260.9	533.1	227.0	94
Retail Stores	34	211.7	198.6	13.1	109.1	13
Offices, Hotels, Finance & Services	21	1,581.2	644.7	936.5	561.5	92
Schools	20	92.7	72.1	20.6	115.0	NA
Institutional/Government	10	257.9	141.5	116.4	39.4	53
All Customers	**280**	**1,038.3**	**266.7**	**771.6**	**226.7**	**95**

Table 5-2: Aggregate Load Impact by Industry for July 2, 2013 PG&E Event

Industry	Number of Customers	Reference Load (MW)	Load with DR (MW)	Load Reduction (MW)	% Load Reduction	% of Aggregate Load Reduction
Agriculture, Mining & Construction	44	41.9	12.6	29.4	70.0	14
Manufacturing	96	160.3	24.6	135.7	84.6	63
Wholesale, Transport & Other Utilities	55	43.7	14.3	29.3	67.1	14
Retail Stores	34	7.2	6.8	0.4	6.2	0
Offices, Hotels, Finance & Services	21	33.2	13.5	19.7	59.2	9
Schools	20	1.9	1.4	0.4	22.2	0
Institutional/Government	10	2.6	1.4	1.2	45.1	1
All Customers	**280**	**290.7**	**74.7**	**216.0**	**74.3**	**100**

Tables 5-3 and 5-4 show the breakdown of load impacts by LCA. Roughly 47% of customers are located in the Other/Combined LCAs regions and another 24% are located in the Greater Bay Area. The largest kW and percent reductions were produced by customers in the Other/Combined LCAs. This means that customers in these LCAs reduce a greater amount of load and reduce a greater percentage of their reference load. Around half of the customers in the manufacturing segment are located in the Other/Combined LCAs which would explain its high kW reductions as well as its high percentage of aggregate reductions. Manufacturing customers are larger than the average customer and therefore contribute more to the aggregate load reduction. Stockton's high level of performance is somewhat artificial – the group of BIP customers in the Stockton LCA has a relatively large proportion of schools. These customers were largely already operating under their FSL on the test event day, which puts downward pressure on the Stockton average load with DR. With a depressed average load with DR, relative to the average Stockton FSL, performance is artificially lifted.

Table 5-3: Average Customer Load Impact by Local Capacity Area for July 2, 2013 PG&E Event

Local Capacity Area	Number of Customers	Reference Load (kW)	Load with DR (kW)	Load Reduction (kW)	Average FSL (kW)	Performance (%)
Greater Bay Area	66	413.1	227.4	185.7	170.2	76
Kern	26	703.6	249.4	454.2	178.7	87
Northern Coast	16	591.3	352.5	238.8	281.1	77
Other / Combined LCAs	132	1,675.2	322.3	1,352.9	278.6	94
Stockton	40	364.3	125.2	239.2	158.1	116
All Customers	**280**	**1,038.3**	**266.7**	**771.6**	**226.7**	**95**

Table 5-4: Aggregate Load Impact by Local Capacity Area for July 2, 2013 PG&E Event

Local Capacity Area	Number of Customers	Reference Load (MW)	Load with DR (MW)	Load Reduction (MW)	% Load Reduction	% of Aggregate Load Reduction
Greater Bay Area	66	27.3	15	12.3	44.9	6
Kern	26	18.3	6.5	11.8	64.5	5
Northern Coast	16	9.5	5.6	3.8	40.4	2
Other / Combined LCAs	132	221.1	42.5	178.6	0.8	83
Stockton	40	14.6	5	9.6	65.6	4
All Customers	**280**	**290.7**	**74.7**	**216**	**74.3**	**100**

Figure 5-3 shows the average load impact in each hour of the retest event day. The average load drop over the four-hour event period was 133.6 kW. This represents a 29% reduction relative to the reference load of 461.6 kW. On average, retested customers provided around 46% of the expected load reduction given the average FSL of 174 kW. These customers' performance during the retest event is an improvement over their performance during the system-wide event when they provided 35% of their expected load reduction. The retest event day load impacts should not be directly compared with system-wide event days; the few customers that did participate in the 2013 retest event date are not representative of the overall program population.

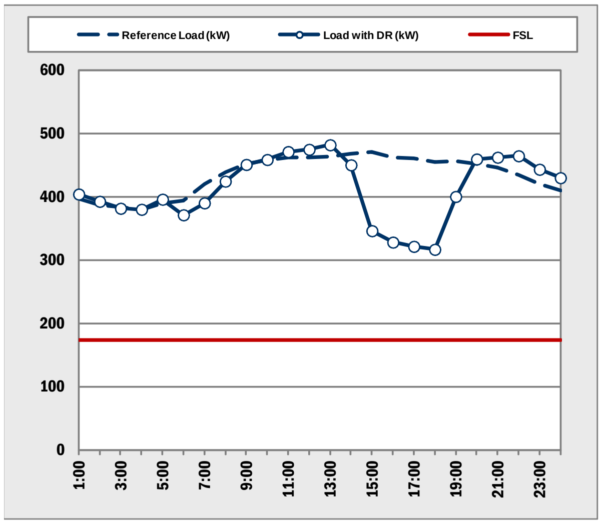
Figure 5-3: Average Load Impact (kW) for PG&E BIP Retest Event (August 27, 2013)

TABLE 1: Menu Options

Type of Results	Average Enrolled Account
Event	Tuesday, August 27, 2013
Customer Characteristic	All Customers

TABLE 2: Output

Number of Accounts	63
Average FSL (kW)	174.0



Hour Ending	Reference Load (kW)	Load with DR (kW)	Load Impact (kW)	Weighted Temp. (°F)	Uncertainty-adjusted Impact - Percentiles				
					10th	30th	50th	70th	90th
1:00	396.5	403.9	-7.4	65.4	-31.7	-17.3	-7.4	2.5	16.8
2:00	386.5	392.4	-5.9	64.2	-30.2	-15.9	-5.9	4.0	18.4
3:00	383.7	381.4	2.2	63.4	-22.1	-7.7	2.2	12.2	26.6
4:00	379.3	379.8	-0.4	62.4	-24.8	-10.4	-0.4	9.5	23.9
5:00	389.3	395.7	-6.4	61.9	-30.9	-16.4	-6.4	3.6	18.0
6:00	393.9	371.2	22.7	61.4	-1.9	12.7	22.7	32.8	47.3
7:00	419.1	389.9	29.2	61.2	4.7	19.2	29.2	39.2	53.7
8:00	438.3	424.3	14.0	62.9	-10.5	4.0	14.0	24.0	38.4
9:00	451.4	450.6	0.7	66.0	-23.7	-9.3	0.7	10.7	25.2
10:00	457.2	458.5	-1.3	69.4	-25.8	-11.3	-1.3	8.7	23.2
11:00	461.7	471.0	-9.3	73.0	-33.9	-19.3	-9.3	0.8	15.4
12:00	461.1	474.4	-13.4	76.3	-38.2	-23.5	-13.4	-3.2	11.4
13:00	463.3	481.7	-18.5	79.6	-43.0	-28.5	-18.5	-8.4	6.0
14:00	467.3	450.0	17.3	82.1	-7.0	7.3	17.3	27.3	41.6
15:00	469.8	346.1	123.7	83.4	99.5	113.8	123.7	133.6	147.9
16:00	461.7	328.0	133.7	83.7	109.5	123.8	133.7	143.6	157.9
17:00	459.8	321.3	138.4	82.8	114.3	128.6	138.4	148.3	162.6
18:00	455.0	316.6	138.4	81.1	114.2	128.5	138.4	148.3	162.6
19:00	456.1	400.1	56.0	78.2	31.8	46.1	56.0	65.9	80.2
20:00	451.5	459.2	-7.8	75.1	-31.9	-17.6	-7.8	2.1	16.4
21:00	445.3	462.1	-16.7	72.5	-40.9	-26.6	-16.7	-6.8	7.4
22:00	433.6	464.3	-30.7	70.9	-54.8	-40.6	-30.7	-20.8	-6.5
23:00	419.7	443.0	-23.3	69.6	-47.5	-33.2	-23.3	-13.4	0.9
0:00	409.2	429.7	-20.6	68.4	-44.7	-30.5	-20.6	-10.7	3.6
	Reference Energy Use (kWh)	Energy Use with DR (kWh)	Change in Energy Use (kWh)	Cooling Degree Hours (Base 70)	Uncertainty-adjusted Impact - Percentiles				
					10th	30th	50th	70th	90th
Daily	10,410.2	9,895.3	514.8	98.7	395.6	466.0	514.8	563.6	634.1

5.2 Over/Under Performance Analysis

For PG&E's over/under performance analysis, data was pooled across the annual system wide PG&E BIP test events from 2011 to 2013. This data included four different event days. For customers who participated in the 2013 retest event, an average of the performance over the two 2013 events was used. This was done so that the retest customers did not disproportionally affect the impact calculations. The 2011 test event for PG&E provided data for 221 PG&E customers and data for 252 customers was included from the 2012 test event. Finally, this year's over/under performance analysis was updated with 280 customers that participated in the 2013 PG&E system-wide test event; PG&E's over/under performance analysis and ex ante load impact estimates incorporate data for multiple years because they were all called under similar conditions.

After pooling the event data, the load shape pattern is determined for each industry by calculating average performance per hour. These performance values are applied to the ex ante reference loads that were estimated using the same regression model used in ex post. Table 5-5 shows the results of the over/under performance analysis by industry for PG&E BIP customers. A value over 100% means that customers in that industry over performed whereas a value under 100% means that customers in that industry under performed. For all industries combined, customers provided 96% of the expected load reduction given their FSL in the first hour of the event and 99% in the last hour of the event.

Performance varies substantially by industry. Customers in Agriculture, Mining & Construction, Wholesale, Transport & Other Utilities and Schools over perform up to 46% during event hours. However, for this year and last year, the high level of performance in the school segment is greatly due to the fact that reference load, let alone observed load, is below the FSL. This makes sense because events tend to take place later in the day when schools aren't in session. Retail stores under perform substantially, providing less than 15% of the expected load reduction. The largest BIP industry (manufacturing) under performs slightly, which drives a large portion of the overall result for all customers.

Although the main purpose of this exercise was to determine over/under performance by industry during the event hours, it also provided information on electric load during pre-event and post-event hours, which was incorporated into the ex ante estimates. As a result, PG&E ex ante load impact estimates show moderate load reductions in the pre-event hours. After the event, aggregate load does not return to the level of the reference load until the end of the day or later. This means that there are substantial load impacts after the event ends.

Table 5-5: PG&E BIP Over/Under Performance Percentages by Industry and Event Hour PG&E System-wide BIP Events from 2011-2013

Industry	% Over/Under Performance			
	Hour Before Event	First Hour of Event	Last Hour of Event	Hour After Event
Agriculture, Mining & Construction	53%	102%	103%	69%
Manufacturing	40%	97%	100%	61%
Wholesale, Transport & Other Utilities	45%	113%	114%	44%
Retail Stores	-3%	6%	14%	11%
Offices, Hotels, Finance & Services	24%	89%	93%	38%
Schools	64%	132%	146%	151%
Institutional/Government	3%	40%	42%	26%
All Customers	**39%**	**96%**	**99%**	**57%**

5.3 Ex Ante Load Impact Estimates

PG&E does not expect enrollments to change or customer load growth due to improving economic conditions for the ex ante forecast horizon 2014-2024. Figures 5-4 and 5-5 show the reference load and estimated load with DR for the average customer on a typical event day based on 1-in-2 and 1-in-10 year weather conditions for 2017-2024. For a 1-in-2 typical event day, the estimated load impact for the average participant is 1,061.6 kW from 1 PM to 6 PM. This represents a 79.2% impact relative to the average reference load of 1,340.3 kW. Based on 1-in-10 year weather conditions, the load impact pattern over the event period is very similar to that in a 1-in-2 weather year, except that the average 1-in-10 weather year load impacts are a little higher – 1,067.5 kW – than in the 1-in-2 weather year.

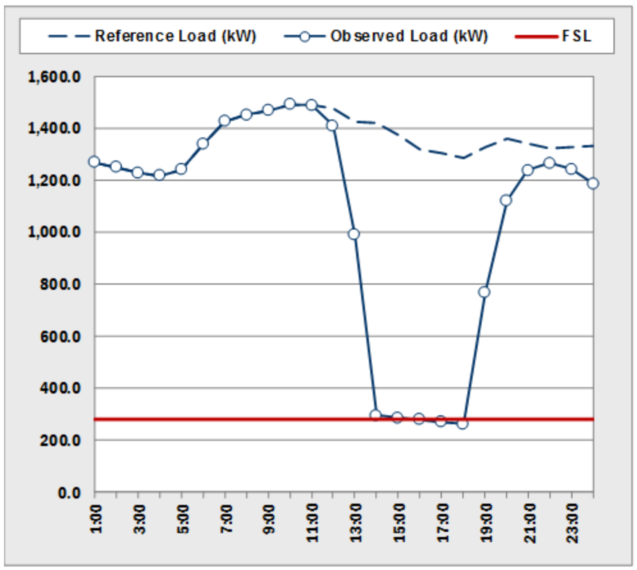
Figure 5-4: PG&E BIP Average Load Impact (kW) per Customer during 2017–2024 for a Typical Event Day Based on 1-in-2 Year Weather Conditions

TABLE 1: Menu Options

Type of Results	Average Enrolled Account
Weather Year	1-in-2
Forecast Year	2017-2024
Day Type	Typical Event Day
Customer Characteristic	All Customers
Demand Category	All Customers

TABLE 2: Output

Number of Accounts	218
Average FSL (kW)	279.9
Proxy Date	-



Note: 1 to 6pm is the event window for the Typical Event Day.

Hour Ending	Reference Load (kW)	Observed Load (kW)	Load Impact (kW)	Weighted Temp (°F)	Uncertainty-adjusted Impact - Percentiles				
					10th	30th	50th	70th	90th
1:00	1266.4	1266.4	0.0	71.3	-56.3	-23.0	0.0	23.0	56.3
2:00	1249.0	1249.0	0.0	67.0	-56.1	-22.9	0.0	22.9	56.1
3:00	1228.2	1228.2	0.0	65.4	-56.1	-23.0	0.0	23.0	56.1
4:00	1216.7	1216.7	0.0	64.3	-56.1	-23.0	0.0	23.0	56.1
5:00	1240.0	1240.0	0.0	63.5	-56.1	-23.0	0.0	23.0	56.1
6:00	1336.8	1336.8	0.0	62.9	-56.1	-22.9	0.0	22.9	56.1
7:00	1426.3	1426.3	0.0	63.0	-56.1	-23.0	0.0	23.0	56.1
8:00	1450.2	1450.2	0.0	66.5	-56.3	-23.0	0.0	23.0	56.3
9:00	1466.4	1466.4	0.0	72.1	-56.7	-23.2	0.0	23.2	56.7
10:00	1489.3	1489.3	0.0	77.4	-56.6	-23.2	0.0	23.2	56.6
11:00	1487.0	1487.0	0.0	82.4	-56.8	-23.2	0.0	23.2	56.8
12:00	1473.5	1410.1	63.5	86.8	6.7	40.2	63.5	86.7	120.3
13:00	1426.0	989.6	436.4	89.9	379.8	413.2	436.4	459.6	493.0
14:00	1418.7	296.0	1122.8	92.2	1066.5	1099.7	1122.8	1145.8	1179.1
15:00	1375.4	286.9	1088.4	94.1	1032.4	1065.5	1088.4	1111.4	1144.5
16:00	1316.5	278.1	1038.4	94.9	982.4	1015.5	1038.4	1061.4	1094.5
17:00	1305.0	269.3	1035.7	94.6	979.8	1012.8	1035.7	1058.6	1091.6
18:00	1285.9	263.4	1022.5	93.3	966.5	999.6	1022.5	1045.4	1078.4
19:00	1326.2	767.6	558.6	90.8	502.3	535.6	558.6	581.6	614.8
20:00	1357.2	1122.4	234.8	86.6	178.3	211.7	234.8	257.9	291.3
21:00	1340.3	1236.5	103.8	81.6	47.3	80.7	103.8	126.9	160.3
22:00	1322.2	1264.7	57.5	77.8	0.9	34.3	57.5	80.7	114.2
23:00	1324.6	1242.2	82.3	75.1	25.5	59.1	82.3	105.6	139.1
0:00	1329.4	1187.1	142.3	73.1	85.8	119.2	142.3	165.4	198.8
	Average Event Reference Load (kW)	Average Event Observed Energy Load (kW)	Average Event Impact (kW)	Cooling Degree Hours (Base 70)	Uncertainty-adjusted Impact - Percentiles				
					10th	30th	50th	70th	90th
Daily	1,340.3	278.7	1,061.6	243.9	1,005.5	1,038.6	1,061.6	1,084.5	1,117.6

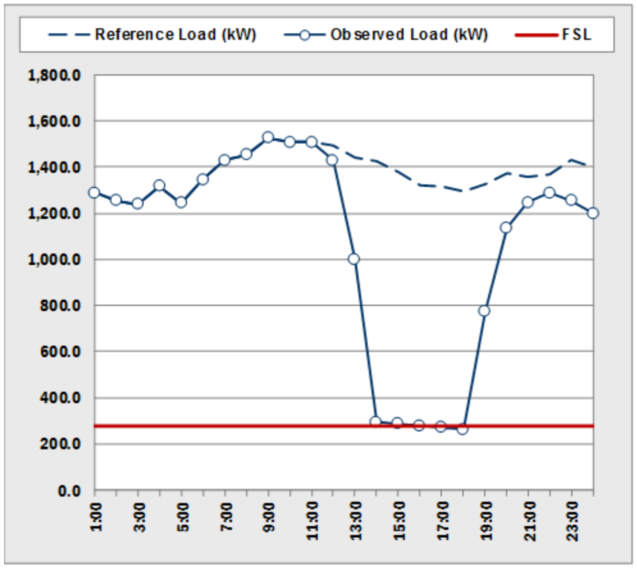
Figure 5-5: PG&E BIP Average Load Impact (kW) per Customer during 2017–2024 for a Typical Event Day Based on 1-in-10 Year Weather Conditions

TABLE 1: Menu Options

Type of Results	Average Enrolled Account
Weather Year	1-in-10
Forecast Year	2017-2024
Day Type	Typical Event Day
Customer Characteristic	All Customers
Demand Category	All Customers

TABLE 2: Output

Number of Accounts	218
Average FSL (kW)	279.9
Proxy Date	-



Note: 1 to 6pm is the event window for the Typical Event Day.

Hour Ending	Reference Load (kW)	Observed Load (kW)	Load Impact (kW)	Weighted Temp (°F)	Uncertainty-adjusted Impact - Percentiles				
					10th	30th	50th	70th	90th
1:00	1288.0	1288.0	0.0	75.3	-58.9	-24.1	0.0	24.1	58.9
2:00	1253.7	1253.7	0.0	73.9	-59.6	-24.4	0.0	24.4	59.6
3:00	1236.9	1236.9	0.0	72.8	-59.2	-24.2	0.0	24.2	59.2
4:00	1316.6	1316.6	0.0	71.5	-86.4	-35.4	0.0	35.4	86.4
5:00	1244.2	1244.2	0.0	70.6	-57.8	-23.6	0.0	23.6	57.8
6:00	1344.5	1344.5	0.0	69.7	-57.6	-23.6	0.0	23.6	57.6
7:00	1428.1	1428.1	0.0	69.5	-58.1	-23.8	0.0	23.8	58.1
8:00	1452.9	1452.9	0.0	72.0	-57.7	-23.6	0.0	23.6	57.7
9:00	1526.2	1526.2	0.0	77.1	-64.8	-26.5	0.0	26.5	64.8
10:00	1508.2	1508.2	0.0	82.0	-60.9	-24.9	0.0	24.9	60.9
11:00	1506.0	1506.0	0.0	86.2	-58.6	-24.0	0.0	24.0	58.6
12:00	1493.1	1428.5	64.7	90.0	6.7	41.0	64.7	88.4	122.6
13:00	1440.7	1001.6	439.1	93.1	381.4	415.5	439.1	462.8	496.9
14:00	1424.4	296.6	1127.8	95.4	1070.5	1104.4	1127.8	1151.3	1185.1
15:00	1378.7	286.8	1091.9	96.7	1035.1	1068.7	1091.9	1115.2	1148.8
16:00	1322.4	278.9	1043.6	97.6	986.8	1020.4	1043.6	1066.8	1100.3
17:00	1315.8	271.4	1044.5	97.6	987.7	1021.2	1044.5	1067.7	1101.2
18:00	1294.2	264.6	1029.6	96.7	972.7	1006.3	1029.6	1052.9	1086.5
19:00	1327.8	775.2	552.6	94.4	495.1	529.1	552.6	576.1	610.0
20:00	1371.8	1135.4	236.3	90.5	178.2	212.6	236.3	260.1	294.4
21:00	1359.3	1246.9	112.4	86.3	53.1	88.1	112.4	136.7	171.7
22:00	1365.6	1288.6	77.0	83.1	16.4	52.2	77.0	101.7	137.5
23:00	1431.9	1254.2	177.7	80.6	112.0	150.8	177.7	204.6	243.4
0:00	1399.5	1197.6	201.8	78.9	132.7	173.6	201.8	230.1	270.9

	Average Event Reference Load (kW)	Average Event Observed Energy Load (kW)	Average Event Impact (kW)	Cooling Degree Hours (Base 70)	Uncertainty-adjusted Impact - Percentiles				
					10th	30th	50th	70th	90th
Daily	1,347.1	279.6	1,067.5	322.5	1,010.6	1,044.2	1,067.5	1,090.8	1,124.4

Table 5-6 shows the aggregate on-peak ex ante load impact estimates for each day type by weather year and forecast year. In accordance with the revised Resource Adequacy hours, the peak period is defined as 1 to 6 PM for the typical event day and the April through October monthly peak days and 4 to 9 PM for the November through March monthly peak days. Throughout the forecast period (2014–2024), the program is expected to be capable of delivering up to 245.9 MW, which occurs during the August monthly peak under 1-in-10 weather conditions in 2017 through 2024. As in the typical event day estimates, the aggregate impacts are higher in a 1-in-10 weather year than in a 1-in-2 weather year for many months. This trend is driven by the weather variables in the model because other factors do not change by weather year within each day type and forecast. The 1-in-10 weather patterns are generally more extreme (hotter in the summer and colder in the winter), which leads to a slight increase in load.

Table 5-6: PG&E BIP Aggregate On-Peak Load Impacts (MW) for Each Day Type by Weather Year and Forecast Year

Weather Year	Day Type	Peak Period	2014	2015	2016	2017–2024
1-in-2	Typical Event Day	1 to 6 PM	231.4	231.4	231.4	231.4
	January Peak	4 to 9 PM	183.3	183.3	183.3	183.3
	February Peak	4 to 9 PM	195.0	195.0	195.0	195.0
	March Peak	4 to 9 PM	197.0	197.0	197.0	197.0
	April Peak	1 to 6 PM	226.8	226.8	226.8	226.8
	May Peak	1 to 6 PM	219.3	219.3	219.3	219.3
	June Peak	1 to 6 PM	228.4	228.4	228.4	228.4
	July Peak	1 to 6 PM	232.8	232.8	232.8	232.8
	August Peak	1 to 6 PM	243.6	243.6	243.6	243.6
	September Peak	1 to 6 PM	230.1	230.1	230.1	230.1
	October Peak	1 to 6 PM	211.1	211.1	211.1	211.1
	November Peak	4 to 9 PM	202.1	202.1	202.1	202.1
	December Peak	4 to 9 PM	186.3	186.3	186.3	186.3
1-in-10	Typical Event Day	1 to 6 PM	232.7	232.7	232.7	232.7
	January Peak	4 to 9 PM	183.3	183.3	183.3	183.3
	February Peak	4 to 9 PM	195.0	195.0	195.0	195.0
	March Peak	4 to 9 PM	197.0	197.0	197.0	197.0
	April Peak	1 to 6 PM	228.4	228.4	228.4	228.4
	May Peak	1 to 6 PM	221.7	221.7	221.7	221.7
	June Peak	1 to 6 PM	231.2	231.2	231.2	231.2
	July Peak	1 to 6 PM	233.1	233.1	233.1	233.1
	August Peak	1 to 6 PM	245.9	245.9	245.9	245.9
	September Peak	1 to 6 PM	230.6	230.6	230.6	230.6
	October Peak	1 to 6 PM	212.4	212.4	212.4	212.4
	November Peak	4 to 9 PM	202.1	202.1	202.1	202.1
	December Peak	4 to 9 PM	186.3	186.3	186.3	186.3

Table 5-7 provides the 2014 and 2017-2024 average and aggregate load impact estimates by LCA for a typical event day under 1-in-2 weather conditions. Throughout the forecast period, aggregate load impacts are primarily concentrated in PG&E's Other and Combined LCAs, accounting for roughly 55% of aggregate impacts. These LCAs contain 62% of customers but customers in the Other/Combined LCAs provide the largest average load reduction per customer. In 2014 and 2017-2024, the Other/Combined LCAs customers provide an average load reduction of over 1,439 kW, whereas the average load impact for the remaining LCAs does not exceed 600 kW.

Table 5-7: 2014 and 2017-2024 Average and Aggregate Load Impacts by LCA Typical Event Day under 1-in-2 Weather Conditions, 1 PM to 6 PM

Forecast Year	LCA	Number of Customers	Reference Load (kW)	Load with DR (kW)	Avg. Load Impact (kW)	Aggregate Load Impact (MW)	% of Total Aggregate Load Impact
2014	Greater Bay Area	40	633.0	238.3	394.6	15.8	6.8
	Kern	23	807.4	234.5	572.9	13.2	5.7
	Other / Combined LCAs	135	1757.5	318.5	1439.1	194.3	83.9
	Stockton	20	572.8	144.4	428.4	8.6	3.7
	All Customers	**218**	**1340.3**	**278.7**	**1061.6**	**231.4**	**100**
2017-2024	Greater Bay Area	40	633.0	238.3	394.6	15.8	6.8
	Kern	23	807.4	234.5	572.9	13.2	5.7
	Other / Combined LCAs	135	1757.5	318.5	1439.1	194.3	55.0
	Stockton	20	572.8	144.4	428.4	8.6	3.7
	All Customers	**218**	**1340.3**	**278.7**	**1061.6**	**231.4**	**100**

5.4 Comparison of Ex Post to Ex Ante Estimates

BIP Ex ante load impact estimates developed by combining three key pieces of information. The complete estimation process is described with more detail in Section 3, but it can be summarized as follows:

A. Estimate reference load for continuing or new BIP participants under 1-in-2 and 1-in-10 weather conditions for 12 day types (typical peak days for each month of the year). These estimates of reference load under varying weather and month conditions are obtained by using the models developed in the ex post analysis.

B. Obtain the FSLs for all continuing or new BIP participants that will be in effect in 2014. These FSLs may or may not be the same as those in effect during the 2013 test events for continuing customers, since customers have the opportunity to change their FSLs in November every year.

C. Apply historic over/under-performance factors to FSLs. Over/under-performance is estimated for each industry and uses the information from the test event as well as the retest event for the subset of customers that did not comply in the first test. Load impact is derived by deducting the expected performance (the kW level customers are expected to reach during event hours, obtained in Step B above) from the estimated reference load obtained in Step A above.

Before comparing the 2013 ex post load impacts to 2014 ex ante estimates, it is helpful to review ex post load impacts for 2012 and 2013 side by side. Table 5-8 presents three years of BIP ex post load impact estimates for PG&E. Since 2011, there has been an increasing trend in BIP enrollment at PG&E; in 2011 there were 222 BIP participants and by 2013 there were 280. While the number of enrolled customers has increased, the reference load of the participating customers has also increased from 995 kW to 1,038 kW. This 4.3% increase in average reference load and 26% increase in enrollment are forces that drive higher delivered load impacts, but they are mitigated by the fact that performance has also fallen from 100% to 95% between 2011 and 2013. In total, these changes have produced 18% more MW of load reduction in 2013 relative to 2011. It is important to keep in mind that when comparing ex post load impact estimates across three years of BIP history, there is only one system-wide event each year that can be used to form the basis of conclusions.

Table 5-8: Multiyear Comparison of PG&E BIP Ex Post Load Impacts

Event Date	Number of Customers	Reference Load (kW)	Load Reduction (kW)	Aggregate Load Reduction (MW)	Load Reduction (%)	Performance (%)	Total CDH
7/2/2013	280	1038.3	771.6	216.0	74	95	315
8/10/2012	252	1103.0	877.0	221.0	80	100	232
9/7/2011	222	995.1	827.5	183.7	83	100	192

Table 5-9 shows the ex post and ex ante results from this load impact evaluation side by side. Aggregate ex ante results are higher than those seen ex post by 7.9% even though PG&E's BIP is projected to have fewer customers and higher FSLs in 2014. This outcome is due to two important factors. First, the 62 customers who have departed the program since the 2013 test event were mostly small customers who have demonstrated low performance in the past. This is evidenced by the fact that the performance factor under ex ante conditions is 100% while FSL performance was 95% for the July 2, 2013 test event. The departure of many small customers has also driven the average reference load up to 1,347 kW under 1-in-2 conditions for a July month peak day in 2014. There is a second important factor to consider in comparing the ex ante and ex post estimates: the 2013 BIP test event day was also a CPP day. BIP customers who dually enroll in CPP make up 29% of the BIP population and the presence of the CPP event depressed BIP reference load on July 2. In other words, these customers were already actively engaged in lowering their reference load before the BIP event was called because they were in the midst of a CPP event. To make a more meaningful comparison between the ex post and ex ante estimates would require some reporting adjustments. On the ex post side, the reference load on the day of the July 2 event for only those 218 customers continuing on the program into 2014 is 1,310 kW. On the ex ante side, the reference load can be estimated assuming that a CPP day is in effect, in which case the reference load estimate for a July monthly peak under 1-in-2 weather is 1,303 kW and 1,304 kW under 1-in-10 weather, only 6-7 kW (less than half a percent) different than the comparable ex post estimate of 1,310 kW.

Table 5-9: PG&E Ex Ante Estimates vs. Ex Post Estimates from the 2013 Evaluation

Result Type	Weather Year / Date	Number of Customers	FSL (kW)	Reference Load (kW)	Performance (%)	Agg. Load Reduction (MW)	Total CDH
ExAnte (2014)	1-in-2, July Monthly Peak	218	279.9	1,347.4	100	233	300
ExAnte (2014)	1-in-10, July Monthly Peak	218	279.9	1,348.3	100	233	369
ExPost (2013)	7/2/2013	280	226.7	1,038.3	95	216	315

Figure 5-6 and Table 5-10 present the differences between ex ante load impact estimates from the 2013 and 2012 BIP load impact evaluations. The 2012 estimates show the effect of the load growth assumptions in the early years of the forecast, and is generally 45 MW or about 15% higher than the 2013 ex ante estimate. This difference is the compound result of a number of factors. The first and most important difference in the forecasted aggregate load impacts is enrollment. The 2013 enrollment forecast is 30% lower than the 2012 enrollment forecast. In addition, the 2012 estimate applied an economic growth factor of 1% annual growth in reference load for each year from 2013 to 2016. But the change in forecasted aggregate load impacts is only 15% (rather than 30%) because other changes to the program population have occurred as well: the reference load in the 2013 evaluation is forecasted to be 229 kW higher in the 2012 forecast, and the FSL is also expected to be 45.8 kW higher in the 2013 forecast than the 2012 forecast. Together, this means that the average BIP customer must reduce load by 1,116.1 kW, as forecasted in this year's evaluation. The same load reduction was forecast to be 931.1 kW in 2012. So, lower enrollments were counteracted with higher forecasted load impact per customer and the combine to produce a lower aggregate load impact in the 2013 evaluation than in the 2012 evaluation.

Figure 5-6: Ex Ante Aggregate Impacts for a 1-in-2 Weather Year, August Monthly Peak Day by Evaluation Year and Forecast Year

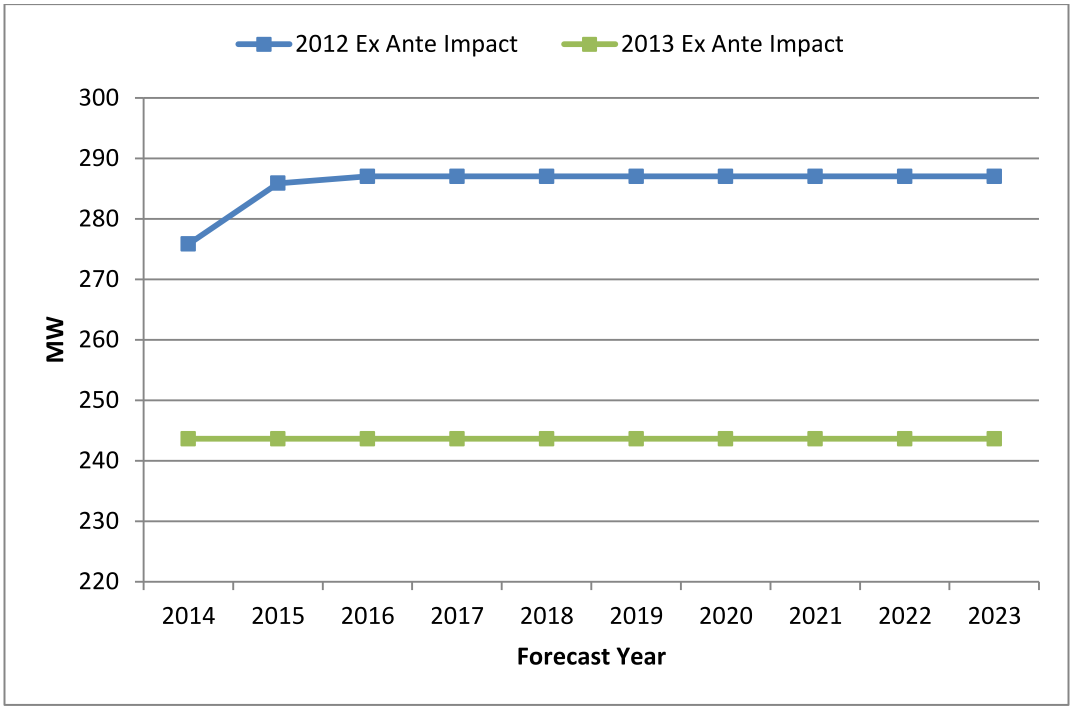


Table 5-10: Ex Ante 1-in-2 Weather Year, August Monthly Peak Day Estimations for Forecast Year 2023 by Evaluation Year

Evaluation Year	Number of Customers	FSL (kW)	Reference Load (kW)	Performance (%)	Agg. Load Reduction (MW)
2013	218	279.9	1396.0	100	243.6
2012	312	234.0	1165.2	99	287.0

6 SDG&E Load Impact Analysis

This section presents 2013 ex post load impact estimates and 2014 through 2024 ex ante load impact estimates for SDG&E's BIP program. The discussion of load impacts provided below focuses on high level – average and aggregate impacts. The remainder of the hourly ex post and ex ante load impact estimates that are required by the Protocols, including uncertainty-adjusted estimates, can be found in the electronic table generator provided under separate cover.

6.1 Ex Post Load Impact Estimates

SDG&E called a BIP event on September 5 that lasted from 1 to 5 PM for all customers. All customers received 30-minute notice of the event. In total, seven customers participated in the event.

Figure 6-1 shows the aggregate impacts in each hour on September 5. The average aggregate load drop from 1 to 5 PM was 1.7 MW. Overall, the load impact represents roughly a 53% reduction relative to the reference load of 3.2 MW. SDG&E's BIP customers demonstrated much improved performance in 2013 relative to 2012: in 2012, customers reduced load to 2.1 MW in aggregate relative to an 0.5 MW FSL, representing 34% FSL compliance. This year, BIP participants at SDG&E reduced load down to their FSL of 1.5MW, providing slightly more than 100% of the necessary reductions.

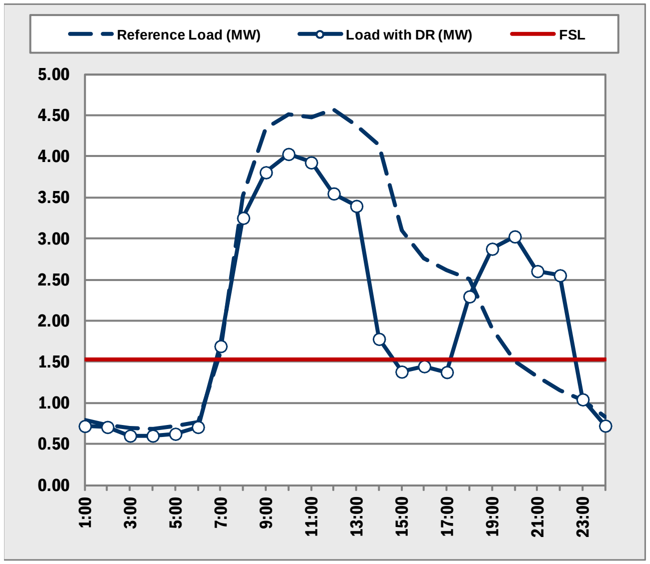
Figure 6-1: Aggregate Load Impact (MW) for SDG&E BIP Event (September 5, 2013)

TABLE 1: Menu options

Type of Results	Aggregate
Event	Thursday, September 05, 2013
Customer Characteristic	All Customers

TABLE 2: Output

Number of Accounts	7
Aggregate FSL (MW)	1.5



Hour Ending	Reference Load (MW)	Load with DR (MW)	Load Impact (MW)	Weighted Temp (F)	Uncertainty Adjusted Impact - Percentiles				
					10th	30th	50th	70th	90th
1:00	0.8	0.7	0.1	72.3	-0.5	-0.2	0.1	0.3	0.7
2:00	0.7	0.7	0.0	70.4	-0.6	-0.2	0.0	0.3	0.6
3:00	0.7	0.6	0.1	71.1	-0.5	-0.1	0.1	0.3	0.7
4:00	0.7	0.6	0.1	71.1	-0.5	-0.2	0.1	0.3	0.7
5:00	0.7	0.6	0.1	70.6	-0.5	-0.1	0.1	0.3	0.7
6:00	0.8	0.7	0.1	71.4	-0.5	-0.2	0.1	0.3	0.6
7:00	1.6	1.7	-0.1	74.3	-0.7	-0.3	-0.1	0.1	0.5
8:00	3.5	3.3	0.3	78.6	-0.3	0.0	0.3	0.5	0.9
9:00	4.3	3.8	0.5	84.6	-0.1	0.3	0.5	0.8	1.1
10:00	4.5	4.0	0.5	87.1	-0.1	0.2	0.5	0.7	1.1
11:00	4.5	3.9	0.5	87.3	-0.1	0.3	0.5	0.8	1.1
12:00	4.6	3.5	1.0	87.4	0.4	0.8	1.0	1.3	1.6
13:00	4.4	3.4	1.0	88.3	0.4	0.7	1.0	1.2	1.6
14:00	4.1	1.8	2.4	88.9	1.7	2.1	2.4	2.6	3.0
15:00	3.1	1.4	1.7	89.0	1.1	1.5	1.7	2.0	2.4
16:00	2.8	1.4	1.3	88.1	0.7	1.1	1.3	1.6	2.0
17:00	2.6	1.4	1.2	85.6	0.6	1.0	1.2	1.5	1.9
18:00	2.5	2.3	0.2	84.3	-0.4	0.0	0.2	0.5	0.9
19:00	1.9	2.9	-1.0	81.9	-1.6	-1.2	-1.0	-0.7	-0.4
20:00	1.5	3.0	-1.5	80.0	-2.1	-1.8	-1.5	-1.3	-0.9
21:00	1.3	2.6	-1.3	75.7	-1.9	-1.5	-1.3	-1.0	-0.7
22:00	1.2	2.6	-1.4	73.9	-2.0	-1.6	-1.4	-1.2	-0.8
23:00	1.0	1.0	0.0	72.3	-0.6	-0.3	0.0	0.2	0.6
0:00	0.8	0.7	0.1	71.1	-0.5	-0.1	0.1	0.3	0.7
	Reference Energy Use (MWh)	Energy Use with DR (MWh)	Change in Energy Use (MWh)	Cooling Degree Hours (Base 70)	Uncertainty Adjusted Impact - Percentiles				
					10th	30th	50th	70th	90th
Daily	54.7	48.7	5.9	225.3	3.0	4.7	5.9	7.1	8.9

Table 6-1 shows the aggregate load impact for all SDG&E BIP participants. The seven event participants span four industry categories, with three or fewer customers within each category. Impacts for specific industries are excluded from this report to protect the confidentiality of the participants' identities.

Table 6-1: Aggregate Load Impact for September 5, 2013 SDG&E Event

Customer Category	Number of Customers	Hour Ending	Ref. Load (MW)	Load with DR (MW)	Load Reduction (MW)	Aggregate FSL (MW)	Performance (%)
All Customers	7	14	4.1	1.8	2.4	1.5	90
		15	3.1	1.4	1.7	1.5	109
		16	2.8	1.4	1.3	1.5	107
		17	2.6	1.4	1.2	1.5	114
		Avg.	**3.2**	**1.5**	**1.7**	**1.5**	**102**

6.2 Over/Under Performance Analysis

The 2013 BIP event was the only historic BIP event used for SDG&E's over/underperformance analysis. Data for multiple years was not pooled with the data from 2013 as in SCE and PG&E's over/under performance analysis. No new customers joined or left the program since the 2013 event and enrollment has shrunk significantly in the past years making customer performance from past events not representative of the performance of the current participant group.

6.3 Ex Ante Load Impact Estimates

Figures 6-2 and 6-3 present aggregate reference load and estimated load with DR on a typical event day based on 1-in-2 and 1-in-10 year weather conditions for the year 2015. For a 1-in-2 typical event day, the estimated load impact is 1.8 MW from 1 to 6 PM. This represents a 54% impact relative to the reference load of 3.4 MW. Load impacts over the event period under 1-in-10 weather conditions are very similar to those in a 1-in-2 weather year because BIP customer usage is not sensitive to temperature. The average load impact across the event period during a 1-in-10 weather year is 1.9 MW.

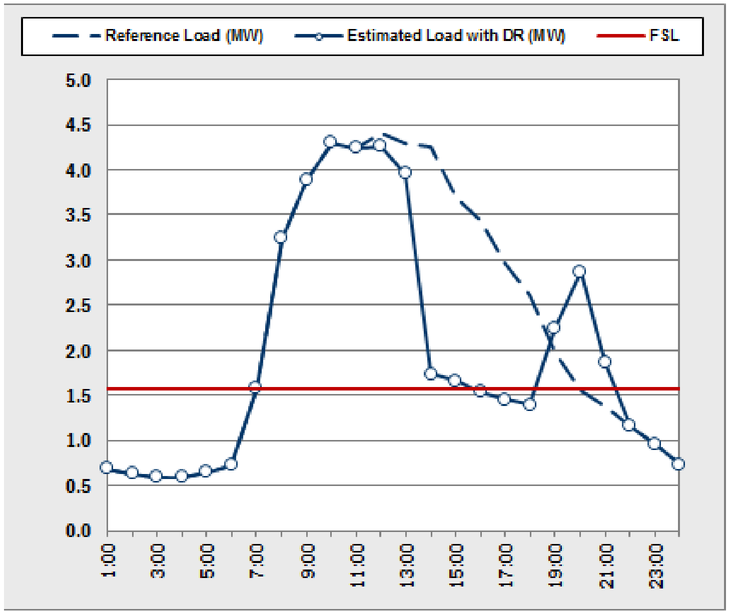
Figure 6-2: SDG&E BIP Aggregate Load Impact (MW) in 2015 for a Typical Event Day Based on 1-in-2 Year Weather Conditions

TABLE 1: Menu Options

Type of Results	Aggregate
Weather Year	1-in-2
Forecast Year	2015 - 2023
Day Type	Typical Event Day
Customer Characteristic	All Customers

TABLE 2: Output

Aggregate FSL (MW)	1.6
Proxy Date	N/A
Average Load Impact (MW) (1-6pm)	1.8
% Load Impact (1-6pm)	54.1%



Hour Ending	Reference Load (MW)	Estimated Load with DR (MW)	Load Impact (MW)	Weighted Temp. (°F)	Uncertainty-adjusted Impact - Percentiles 10th	30th	50th	70th	90th
1:00	0.7	0.7	0.0	69.4	-0.6	-0.2	0.0	0.2	0.6
2:00	0.6	0.6	0.0	68.6	-0.6	-0.2	0.0	0.2	0.6
3:00	0.6	0.6	0.0	67.9	-0.6	-0.2	0.0	0.2	0.6
4:00	0.6	0.6	0.0	67.6	-0.6	-0.2	0.0	0.2	0.6
5:00	0.6	0.6	0.0	67.6	-0.6	-0.2	0.0	0.2	0.6
6:00	0.7	0.7	0.0	67.9	-0.6	-0.2	0.0	0.2	0.6
7:00	1.6	1.6	0.0	68.0	-0.6	-0.2	0.0	0.2	0.6
8:00	3.2	3.2	0.0	72.6	-0.6	-0.2	0.0	0.2	0.6
9:00	3.9	3.9	0.0	78.2	-0.6	-0.2	0.0	0.2	0.6
10:00	4.3	4.3	0.0	83.2	-0.6	-0.2	0.0	0.2	0.6
11:00	4.2	4.2	0.0	88.3	-0.6	-0.2	0.0	0.2	0.6
12:00	4.4	4.3	0.1	89.0	-0.5	-0.1	0.1	0.4	0.7
13:00	4.3	4.0	0.3	88.1	-0.3	0.1	0.3	0.6	0.9
14:00	4.3	1.7	2.5	86.7	1.9	2.3	2.5	2.8	3.1
15:00	3.7	1.7	2.0	86.4	1.4	1.8	2.0	2.3	2.6
16:00	3.4	1.5	1.9	85.5	1.3	1.6	1.9	2.1	2.5
17:00	3.0	1.4	1.5	84.4	0.9	1.3	1.5	1.8	2.1
18:00	2.6	1.4	1.2	81.8	0.6	1.0	1.2	1.5	1.8
19:00	2.0	2.2	-0.3	78.5	-0.9	-0.5	-0.3	0.0	0.3
20:00	1.6	2.9	-1.3	75.0	-1.9	-1.6	-1.3	-1.1	-0.7
21:00	1.4	1.9	-0.5	72.9	-1.1	-0.7	-0.5	-0.3	0.1
22:00	1.2	1.2	0.0	72.1	-0.6	-0.2	0.0	0.2	0.6
23:00	1.0	1.0	0.0	71.5	-0.6	-0.2	0.0	0.2	0.6
0:00	0.7	0.7	0.0	70.1	-0.6	-0.2	0.0	0.2	0.6
	Reference Energy Use (MWh)	Energy Use with DR (MWh)	Change in Energy Use (MWh)	Cooling Degree Hours (Base 70)	Uncertainty-adjusted Impact - Percentiles 10th	30th	50th	70th	90th
Daily	54.5	46.9	7.5	174.2	4.6	6.4	7.5	8.7	10.5

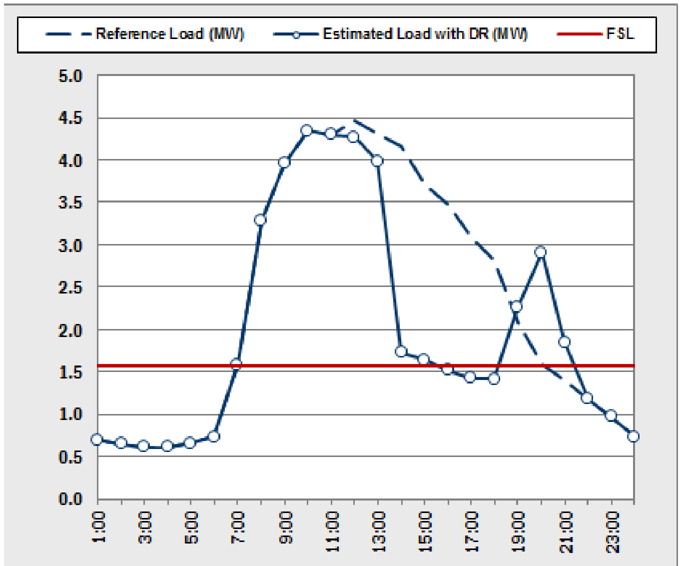
Figure 6-3 SDG&E BIP Aggregate Load Impact (MW) in 2015 for a Typical Event Day Based on 1-in-10 Year Weather Conditions

TABLE 1: Menu Options

Type of Results	Aggregate
Weather Year	1-in-10
Forecast Year	2015 - 2023
Day Type	Typical Event Day
Customer Characteristic	All Customers

TABLE 2: Output

Aggregate FSL (MW)	1.6
Proxy Date	N/A
Average Load Impact (MW) (1-6pm)	1.9
% Load Impact (1-6pm)	55.2%



Hour Ending	Reference Load (MW)	Estimated Load with DR (MW)	Load Impact (MW)	Weighted Temp. (°F)	Uncertainty-adjusted Impact - Percentiles				
					10th	30th	50th	70th	90th
1:00	0.7	0.7	0.0	72.2	-0.6	-0.2	0.0	0.2	0.6
2:00	0.6	0.6	0.0	71.6	-0.6	-0.2	0.0	0.2	0.6
3:00	0.6	0.6	0.0	71.2	-0.6	-0.2	0.0	0.2	0.6
4:00	0.6	0.6	0.0	70.3	-0.6	-0.2	0.0	0.2	0.6
5:00	0.7	0.7	0.0	70.1	-0.6	-0.2	0.0	0.2	0.6
6:00	0.7	0.7	0.0	69.9	-0.6	-0.2	0.0	0.2	0.6
7:00	1.6	1.6	0.0	70.7	-0.6	-0.2	0.0	0.2	0.6
8:00	3.3	3.3	0.0	75.2	-0.6	-0.2	0.0	0.2	0.6
9:00	4.0	4.0	0.0	79.2	-0.6	-0.3	0.0	0.3	0.6
10:00	4.3	4.3	0.0	84.1	-0.6	-0.2	0.0	0.2	0.6
11:00	4.3	4.3	0.0	87.8	-0.6	-0.2	0.0	0.2	0.6
12:00	4.5	4.3	0.2	89.7	-0.4	-0.1	0.2	0.4	0.8
13:00	4.3	4.0	0.3	89.6	-0.3	0.1	0.3	0.6	0.9
14:00	4.2	1.7	2.4	89.9	1.8	2.2	2.4	2.7	3.1
15:00	3.7	1.6	2.1	89.6	1.4	1.8	2.1	2.3	2.7
16:00	3.5	1.5	2.0	88.1	1.3	1.7	2.0	2.2	2.6
17:00	3.1	1.4	1.6	86.0	1.0	1.4	1.6	1.9	2.3
18:00	2.8	1.4	1.4	83.9	0.8	1.1	1.4	1.7	2.0
19:00	2.1	2.3	-0.2	80.6	-0.8	-0.4	-0.2	0.1	0.4
20:00	1.6	2.9	-1.3	76.7	-1.9	-1.6	-1.3	-1.1	-0.7
21:00	1.4	1.9	-0.5	75.2	-1.0	-0.7	-0.5	-0.2	0.1
22:00	1.2	1.2	0.0	74.4	-0.6	-0.2	0.0	0.2	0.6
23:00	1.0	1.0	0.0	73.0	-0.6	-0.2	0.0	0.2	0.6
0:00	0.7	0.7	0.0	72.0	-0.6	-0.2	0.0	0.2	0.6
	Reference Energy Use (MWh)	Energy Use with DR (MWh)	Change in Energy Use (MWh)	Cooling Degree Hours (Base 70)	Uncertainty-adjusted Impact - Percentiles				
					10th	30th	50th	70th	90th
Daily	55.4	47.3	8.1	211.0	5.2	6.9	8.1	9.3	11.0

Table 6-4 shows the aggregate on-peak ex ante load impact estimates for each day type by weather year and forecast year. In accordance with the revised Resource Adequacy hours, the peak period is defined as 1 to 6 PM for the typical event day occurring on April through October monthly peak days and 4 to 9 PM for the November through March monthly peak days. Aggregate impacts fluctuate throughout the year as a result of the change in peak period timing. Aggregate load impacts for the 1-in-10 weather year vary from 0.1 MW to 0.4 MW in November through March and 0.4 MW to 2.0 MW in April through October. This variation is due to the fact that BIP participants' electricity usage is higher from 1 to 6 PM than it is from 4 to 9 PM, as shown in Figures 6-2 and 6-3.

Table 6-4: SDG&E BIP Aggregate On-peak Load Impacts (MW) for each Day Type by Weather Year and Forecast Year

Weather Year	Day Type	Peak Period	2014	2015	2016–2024
1-in-2	Typical Event Day	1 to 6 PM	1.8	1.8	1.8
	January Peak	4 to 9 PM	0.1	0.1	0.1
	February Peak	4 to 9 PM	0.2	0.2	0.2
	March Peak	4 to 9 PM	0.3	0.3	0.3
	April Peak	1 to 6 PM	0.9	0.9	0.9
	May Peak	1 to 6 PM	1.1	1.1	1.1
	June Peak	1 to 6 PM	1.1	1.1	1.1
	July Peak	1 to 6 PM	1.0	1.0	1.0
	August Peak	1 to 6 PM	1.8	1.8	1.8
	September Peak	1 to 6 PM	1.3	1.3	1.3
	October Peak	1 to 6 PM	0.6	0.6	0.6
	November Peak	4 to 9 PM	0.4	0.4	0.4
	December Peak	4 to 9 PM	0.1	0.1	0.1
1-in-10	Typical Event Day	1 to 6 PM	1.9	1.9	1.9
	January Peak	4 to 9 PM	0.1	0.1	0.1
	February Peak	4 to 9 PM	0.2	0.2	0.2
	March Peak	4 to 9 PM	0.3	0.3	0.3
	April Peak	1 to 6 PM	1.2	1.2	1.2
	May Peak	1 to 6 PM	1.1	1.1	1.1
	June Peak	1 to 6 PM	1.1	1.1	1.1
	July Peak	1 to 6 PM	1.1	1.1	1.1
	August Peak	1 to 6 PM	2.0	2.0	2.0
	September Peak	1 to 6 PM	1.3	1.3	1.3
	October Peak	1 to 6 PM	0.4	0.4	0.4
	November Peak	4 to 9 PM	0.4	0.4	0.4
	December Peak	4 to 9 PM	0.1	0.1	0.1

6.4 Comparison of Ex Post to Ex Ante Estimates

BIP Ex ante load impact estimates developed by combining three key pieces of information. The complete estimation process is described with more detail in Section 3, but it can be summarized as follows:

A. Estimate reference load for continuing or new BIP participants under 1-in-2 and 1-in-10 weather conditions for 12 day types (typical peak days for each month of the year). These estimates of reference load under varying weather and month conditions are obtained by using the models developed in the ex post analysis.

B. Obtain the FSLs for all continuing or new BIP participants that will be in effect in 2014. These FSLs may or may not be the same as those in effect during the 2013 test events for continuing customers, since customers have the opportunity to change their FSLs in November every year.

C. Apply historic over/under-performance factors to FSLs. Over/under-performance is estimated for each industry for each IOU. Load impact is derived by deducting the expected performance (the kW level customers are expected to reach during event hours, obtained in Step B above) from the estimated reference load obtained in Step A above.

Before comparing the 2013 ex post load impacts to 2014 ex ante estimates, it is helpful to review ex post load impacts for 2012 and 2013 side by side. Table 6-5 presents two years of BIP ex post load impact estimates for SDG&E. There were four more customers participating in BIP SDG&E in 2012 than there are in 2013. However, the average SDG&E BIP participant's average load reduction greatly increased from 2012 to 2013 – from 0.8 MW in 2012 to 1.7 MW in 2013. During this period aggregate reference load increased from 2.9 MW in 2012 to 3.2 MW in 2013 and the aggregate FSL increased from 0.47 MW in 2012 to 1.5MW in 2013. Together, these changes reflect a strong improvement in performance: in 2012 performance stood at 34% and in 2013 it is 102%. That being said, with such small numbers of customers in the program, the uncertainty around the estimates of reference load are greater than they are for the other two IOUs. BIP performance at SDG&E should be cited in tandem with the sample size and uncertainty.

Table 6-5: Multiyear Comparison of SDG&E BIP Ex Post Load Impacts

Event Date	Number of Customers	Reference Load (kW)	Load Reduction (kW)	Aggregate Load Reduction (MW)	Load Reduction (%)	Performance (%)	Total CDH
9/5/2013	7	450.3	236.5	1.7	53	102	225
9/14/2012	11	267.7	76.2	0.8	28	34	261

Table 6-6 shows the ex post and ex ante results from this load impact evaluation side by side. Aggregate ex ante results are smaller than those seen ex post by 42% even though SDG&E's BIP program is projected to have the same number of customers and higher FSLs in 2014. This remarkable outcome is due to one important factor: weather. The total CDH during the September 5 event was roughly 28%

higher than the July monthly peak in 1-in-2 and 1-in-10 weather conditions. This causes a large increase in estimated customer reference loads. If customers are expected to have the same performance on a smaller reference load, they need to reduce their electricity usage by much less, therefore resulting in smaller aggregate load reductions.

Table 6-6: Ex Ante Estimates vs. Ex Post Estimates from the 2013 Evaluation

Result Type	Weather Year / Date	Number of Customers	FSL (kW)	Reference Load (kW)	Performance (%)	Agg. Load Reduction (MW)	Total CDH
ExAnte (2014)	1-in-2, July Monthly Peak	7	224.0	364.5	97	1	161
ExAnte (2014)	1-in-10, July Monthly Peak	7	224.0	379.8	100	1	182
ExPost (2013)	9/5/2013	7	218.4	450.3	102	2	225

Figure 6-4 and Table 6-7 present the differences between ex ante load impact estimates from the 2013 and 2012 BIP load impact evaluations. Both the 2012 and 2013 load impact evaluations assume no load growth for participating customers in addition to no enrollment growth. But a key difference is in the number of customers – the 2013 load impact evaluation assumes 36% fewer customers than in 2012. The FSL projected for the forecast horizon is also very different in the 2013 load impact evaluation: the 2012 ex ante FSL for the average customer was 42.9 kW while the 2013 ex ante FSL is 224 kW. Reference load is also far higher for the average customer while FSL performance has also dramatically increased to 101% in the 2013 evaluation from 34% in the 2012 evaluation. Despite the 36% drop in enrollment, in this 2013 evaluation, aggregate load impacts are forecast to be more than double the magnitude of load impacts forecast in 2012. The increased performance in 2013 is also likely due to SDG&E's efforts to encourage free-riders to exit the program: beginning in 2012, if a customer does not reduce its load below the FSL during an event the FSL is raised to the amount of energy the customer used during the event. Since the monthly capacity payment is equal to the average monthly on-peak energy use load minus the FSL, raising the FSL lowers future capacity payments to customers who did not perform during the event.

Figure 6-4: Ex Ante Aggregate Impacts for a 1-in-2 Weather Year, August Monthly Peak Day by Evaluation Year and Forecast Year

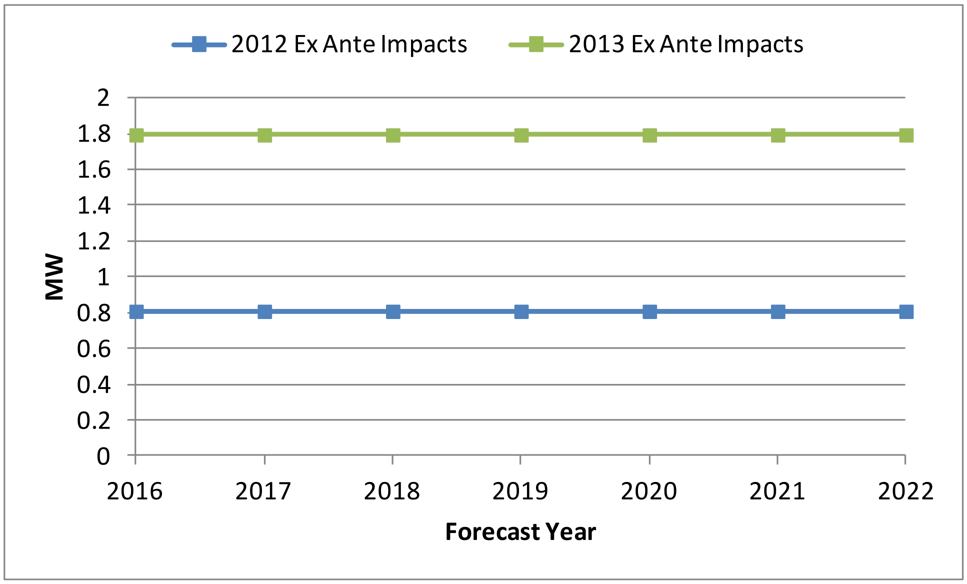


Table 6-6: Ex Ante 1-in-2 Weather Year, August Monthly Peak Day Estimations for Forecast Year 2023 by Evaluation Year

Evaluation Year	Number of Customers	FSL (kW)	Reference Load (kW)	Performance (%)	Agg. Load Reduction (MW)
2013	7	224	477.7	101	1.8
2012	11	42.9	259.5	34	0.8

7 Recommendations

The events in that were called in 2013 provided more information about how BIP customers respond to the call to reduce load during event hours, and this additional information improves the quality of the over/under performance analysis, which in turn, improves the quality of the ex ante estimates. We recommend that all IOUs continue to call at least one event each year, especially in light of the fact that the mix of customers on the program can and does change from year to year. When calling a test event, all the IOUs need to consider the event conditions that they are attempting to simulate. If a BIP test event is meant to simulate a generation supply shortage, we recommend giving at least one day notice, but not the exact timing of the event. If a BIP test event is meant to simulate a transmission or distribution outage, no day-ahead notice should be given.

Appendix A Table of Hourly Values for Figure 3-1

In Figure 3-1, the magnitude of the difference between predicted and actual kW is unclear because the two lines for each IOU are close together on the graph. Table A-1 provides the underlying hourly predicted and actual kW values that are reflected in Figure 3-1.

Table of Hourly Values for Figure 3-1

Table A-1: Hourly Predicted and Actual kW Values Reflected in Figure 3-1

Hour	SCE				PG&E				SDG&E			
	Actual kW	Predicted kW	Error	% Error	Actual kW	Predicted kW	Error	% Error	Actual kW	Predicted kW	Error	% Error
1	1,110.7	1,138.6	-27.9	-2.5%	1,047.8	1,046.3	1.6	0.1%	99.5	93.5	6.0	6%
2	1,100.3	1,135.6	-35.3	-3.2%	1,028.2	1,022.2	6.0	0.6%	94.9	92.7	2.3	2%
3	1,096.7	1,126.5	-29.8	-2.7%	1,000.7	998.5	2.2	0.2%	90.2	87.8	2.3	3%
4	1,102.3	1,127.2	-24.9	-2.3%	996.0	987.7	8.3	0.8%	89.6	86.2	3.4	4%
5	1,124.8	1,151.3	-26.6	-2.4%	1,025.1	1,017.0	8.1	0.8%	92.3	86.9	5.4	6%
6	1,176.8	1,193.2	-16.4	-1.4%	1,100.9	1,084.1	16.8	1.5%	103.5	97.0	6.4	6%
7	1,209.8	1,227.8	-18.1	-1.5%	1,158.8	1,149.6	9.2	0.8%	229.7	228.7	1.0	0%
8	1,253.1	1,274.0	-20.9	-1.7%	1,172.9	1,177.1	-4.2	-0.4%	462.1	483.3	-21.3	-5%
9	1,271.8	1,294.8	-23.1	-1.8%	1,179.6	1,197.9	-18.2	-1.6%	564.0	593.2	-29.2	-5%
10	1,286.3	1,298.5	-12.2	-0.9%	1,186.0	1,201.3	-15.3	-1.3%	602.1	624.0	-21.9	-4%
11	1,297.6	1,296.3	1.3	0.1%	1,185.6	1,197.8	-12.1	-1.0%	615.1	596.7	18.4	3%
12	1,278.2	1,278.4	-0.2	0.0%	1,188.6	1,198.3	-9.7	-0.8%	624.4	611.4	13.0	2%
13	1,251.9	1,263.2	-11.3	-0.9%	1,162.9	1,171.3	-8.3	-0.7%	574.1	598.7	-24.6	-4%
14	1,243.7	1,260.8	-17.1	-1.4%	1,144.4	1,162.5	-18.1	-1.6%	549.9	583.9	-34.0	-6%
15	1,219.8	1,232.5	-12.7	-1.0%	1,112.6	1,129.6	-17.1	-1.5%	484.5	476.4	8.0	2%
16	1,192.0	1,212.1	-20.2	-1.7%	1,077.0	1,089.0	-12.0	-1.1%	447.4	438.9	8.5	2%
17	1,171.5	1,190.7	-19.2	-1.6%	1,071.6	1,084.1	-12.6	-1.2%	435.5	410.2	25.3	6%
18	1,154.8	1,165.7	-10.9	-0.9%	1,053.1	1,069.8	-16.8	-1.6%	445.5	388.5	57.0	13%
19	1,160.4	1,166.9	-6.6	-0.6%	1,081.5	1,100.5	-18.9	-1.8%	333.8	294.3	39.4	12%
20	1,174.8	1,171.6	3.1	0.3%	1,109.6	1,120.8	-11.3	-1.0%	253.7	236.5	17.2	7%
21	1,195.8	1,183.7	12.1	1.0%	1,105.5	1,113.2	-7.7	-0.7%	209.0	193.2	15.8	8%
22	1,195.7	1,168.5	27.2	2.3%	1,098.8	1,104.3	-5.6	-0.5%	173.1	164.9	8.2	5%
23	1,173.2	1,172.5	0.7	0.1%	1,098.2	1,098.5	-0.2	0.0%	136.0	139.1	-3.1	-2%
24	1,173.7	1,161.9	11.7	1.0%	1,097.7	1,095.8	1.9	0.2%	100.2	98.5	1.7	2%
Avg. (1-6 PM)	**1,196.4**	**1,212.4**	**-16**	**-1.3%**	**1,091.7**	**1,107.0**	**-15.3**	**-1.4%**	**472.5**	**459.6**	**13**	**3.2%**