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2011 Load Impact Evaluation of California's Statewide Base Interruptible Program

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1 Executive Summary

Each of California's three major investor-owned utilities, Pacific Gas and Electric (PG&E), Southern California Edison (SCE) and San Diego Gas & Electric (SDG&E), offer the Base Interruptible Program (BIP). Although minor differences in the tariffs exist across the three utilities, for all three, BIP is a tariff based, emergency-triggered demand response (DR) program that the utilities can dispatch for California Independent System Operator (CAISO) system emergencies and local emergencies. 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 penalty assessed on a kWh basis. As of May 2012, enrollment in BIP equaled 656 accounts for SCE, 230 accounts for PG&E and 17 accounts for SDG&E.

One of the most important issues facing the statewide BIP program is the cap on emergency DR programs that was adopted in 2010 by the utilities, CAISO and the California Public Utilities 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 2012, the limit will be 3% 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 utility. Considering that SCE is near its allocation of the cap, BIP enrollment is projected to remain constant throughout the ex ante forecast period (2012-2022). PG&E and SDG&E have more room for growth in emergency DR within their cap allocations. PG&E expects enrollment in its BIP program to increase over the next few years, reaching 248 participants by the end of 2022. SDG&E BIP enrollment is expected to equal 105 in by the end of 2014 and then remain constant afterwards.

This report documents the ex post and ex ante load impact estimates associated with BIP for all three of California's major investor-owned utilities. Ex post estimates are provided for 2011 events. Ex ante estimates are provided for the years 2012 through 2022.

1.1 Ex Post Load Impact Estimates

This report provides ex post load impact estimates for events called in 2011. Each utility called a territory-wide test BIP event in 2011. SCE called a test event on September 21 from 2 PM to 4 PM. PG&E implemented a test event on September 7 from 3 PM to 5 PM. In addition to this territory-wide test event, PG&E called an actual, localized event on March 11 for the nine participants in group 8 who are located in the Humboldt region.[2] SDG&E called a BIP test event on August 18 that lasted from 12 PM to 4 PM for BIP option A customers and 3 PM to 6 PM for the single BIP option B customer.

SCE held a system-wide test event with 24-hour advance notice for BIP on September 21 from 2 PM to 4 PM, which was the first SCE BIP event since 2009. Overall, 661 customers participated in the event. The average load drop over the two-hour event period was 790 kW. The aggregate load drop during the

1 CPUC Rulemaking 07-01-041, Phase 3, Appendix A. February 2, 2010.

2 For the PG&E BIP program, customers are divided into different geographical groups that can be dispatched individually for local emergencies such as this one in the Humboldt region on March 11.

event period was 522 MW. This represents nearly a 70% reduction relative to the estimated reference load of 751 MW. From 3 PM to 4 PM, aggregate load lowered to 149 MW and customers provided 91% of the expected load reduction given the aggregate FSL of 97 MW.

PG&E's system-wide BIP test event was held on September 7, 2011 and lasted from 3 PM to 5 PM. The event included all 222 customers who were enrolled in BIP at that time. Some of the PG&E account representatives might have perceived a high likelihood of the event ahead of time given the weather conditions and the timing of prior test events, and some of the BIP customers might have been reminded about their event preparedness. The event and its start-time were not officially communicated until the event notice was issued 30 minutes before the event. The average load drop over the two-hour event period was 827.5 kW. The aggregate load drop during the event period was 183.7 MW. This represents roughly an 83% reduction relative to the reference load of 220.9 MW. On aggregate, customers performed as expected as the event-period load of 37.2 MW was nearly the same as the aggregate FSL of 36.7 MW.

In addition to this system-wide test event, PG&E called an actual, localized event on March 11 for the nine participants in group 8 who are located in the Humboldt region. This was a short event lasting from 7:35 AM to 8:08 AM, as a result of the tsunami warning for the coastal areas of California and Oregon and the Humboldt Bay Generation Station shutdown. All 9 participants fully complied during the event time period by reducing load below their FSLs, with an average load impact of 677.8 kW per customer. The aggregate load impact specifically for the event time period was around 6.1 MW.

SDG&E called a BIP test event on August 18, 2011 that lasted from 12 PM to 4 PM for BIP option A customers and 3 PM to 6 PM for the single BIP option B customer. Option A customers received 30-minute notice of the event and Option B customers received 3 hours. These were the minimum notification times allowed by the tariff. In total, 21 customers participated in the event. From 3 PM to 4 PM when all customers were participating in the event, the average load drop was 114.1 kW. The aggregate load drop from 3 PM to 4 PM was 2.4 MW. This represents roughly a 35% reduction relative to the reference load of 6.9 MW. The 3 PM to 4 PM aggregate load of 4.5 MW was substantially higher than the aggregate FSL of 0.6 MW. BIP customers under performed during this event, providing only 38% of the 6.3 MW reduction that participants needed in order to be in compliance.

1.2 Ex Ante Load Impact Estimates

BIP is a large, statewide emergency resource that is expected to experience modest growth over the next few years. Figure 1-1 shows the amount of DR available from 2012 through 2022 by utility. For the August monthly peak day in a 1-in-2 weather year, the program is projected to deliver 778 MW in 2012. By 2018, the aggregate load impact is expected to grow by 10.2% to 854 MW. This growth is a result of increased enrollment among PG&E and SDG&E BIP customers and load growth among SCE and PG&E participants. From 2018 through 2022, the aggregate impact decreases slightly because PG&E anticipates a small decline in BIP enrollment and in usage among its large business customers in those years. In each forecast year, around 72% to 76% of the aggregate load reduction comes from SCE, 24% to 28% from PG&E and the remaining 0.2% to 0.7% from SDG&E. These results are not significantly different for 1-in-10 weather year conditions because BIP customers are not weather-sensitive on average.

Figure 1-1:
2012-2022 Aggregate Load Impacts by Utility and Forecast Year
August Monthly Peak Day in a 1-in-2 Weather Year

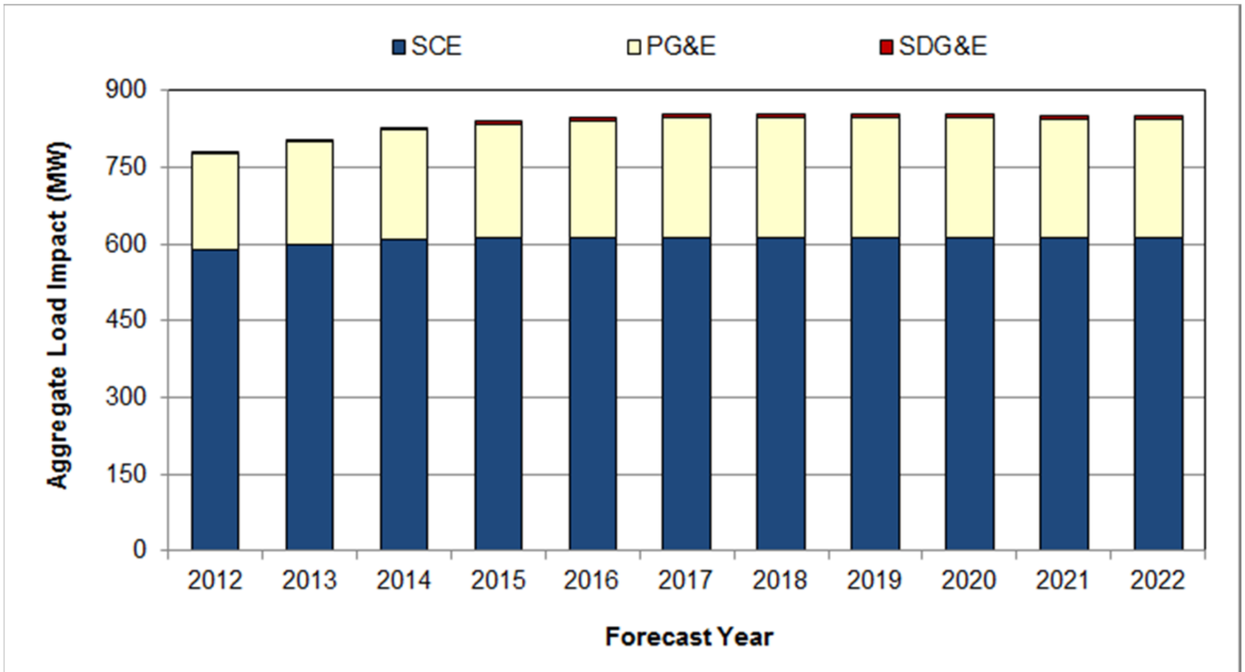
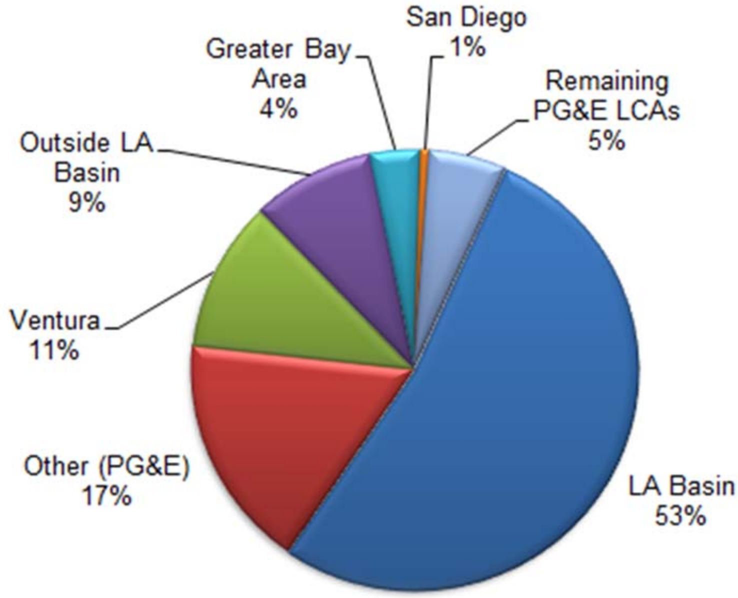


Figure 1-2 shows the distribution of statewide aggregate load impacts in 2015 by local capacity area (LCA). LCAs are CAISO-designated planning regions in which utilities must meet local resource adequacy requirements. For a typical event day in a 1-in-2 weather year in 2015, the statewide aggregate load impact is 830 MW. The LA Basin LCA in SCE's service territory comprises 53% of the statewide aggregate load impact. PG&E's Other LCA is the only area outside of SCE's territory that provides more than 4% of the statewide aggregate load impact.

Figure 1-2:
Distribution of 2015 Statewide Aggregate Load Impacts by Local Capacity Area
Typical Event Day under 1-in-2 Weather Conditions
Total Statewide Aggregate Impact = 839 MW



2 Introduction and Program Summary

This report documents the 2011 ex post load impact estimates for California's statewide Base Interruptible Program (BIP) and provides ex ante load impact estimates from 2012 through 2022. Each of California's three major investor-owned utilities, Southern California Edison (SCE), Pacific Gas and Electric (PG&E) and San Diego Gas & Electric (SDG&E), offer the BIP program. Although minor differences in the tariffs exist across the three utilities, for all three, BIP is a tariff based, emergency-triggered demand response (DR) program that the utilities can dispatch for California Independent System Operator (CAISO) system emergencies and local emergencies. 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 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[3] that the three utilities must modify their tariffs. The revised tariffs allow the utilities 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, Stage 2 alerts or test events) remain.

This report provides ex post load impact estimates for events called in 2011. Each utility called a BIP event in 2011. SCE called a test event on September 21 from 2 PM to 4 PM. PG&E implemented a test event on September 7 from 3 PM to 5 PM. In addition to this system-wide test event, PG&E called an actual, localized event for the nine group 8 participants located in the Humboldt region on March 11.[4] There was one test event held for SDG&E's BIP program in 2011. That event occurred on August 18 and lasted for four hours for option A customers (12 PM to 4 PM) and three hours for option B customers (3 PM to 6 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 2012 to 2022. The load impact estimates presented here are intended to conform to the requirements of the California Public Utilities Commission (CPUC) Demand Response Load Impact Protocols.[5]

2.1 Cap on Emergency DR Programs

One of the most important issues facing the statewide BIP program is the cap on emergency DR programs that was adopted in 2010 by the utilities, CAISO and CPUC.[6] This cap limits the growth of emergency DR programs to a certain percentage of the recorded all-time coincident CAISO peak load.

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

[4] For the PG&E BIP program, customers are divided into different geographical groups that can be dispatched individually for local emergencies such as this one in the Humboldt region on March 11th.

[5] CPUC D.08-04-050 issued on April 28, 2008 with Attachment A.

[6] CPUC Rulemaking 07-01-041, Phase 3, Appendix A. February 2, 2010.

For 2012, the limit will be 3% with a 10% tolerance band. The cap will gradually lower to 2% of CAISO peak load without a tolerance band from 2016 onwards. The cap will be allocated to the utilities *in proportion* to the following:

- PG&E: 400 MW;
- SCE: 800 MW; and
- SDG&E: 20 MW.

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

Although there are other emergency DR programs run by the utilities, 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 utility 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 2 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 180 hours per calendar year. An interruption event may be called at any time during the year.

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 May 2012, SCE had 656 service accounts enrolled in the BIP program, of which 90% were in the 30-minute notification option. As indicated in Table 2-1, the largest number of accounts is from the manufacturing sector (56% of the total).

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

Industry	Number of Accounts
Agriculture, Mining & Construction	62
Manufacturing	370
Wholesale, Transport & Other Utilities	67
Retail Stores	39
Offices, Hotels, Finance & Services	43
Schools	66
Institutional/Government	9
Total	**656**

SCE's service territory includes three CAISO local capacity areas (LCA).[7] The vast majority of service accounts (551 out of the 656 BIP accounts) are in the LA Basin LCA; 80 are located in the Ventura LCA and the remaining 25 are in the Outside LA Basin LCA.

In the ex ante analysis, it is assumed that enrollment remains the same from 2012 through 2022. 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 2011. That event occurred on September 21 and lasted for two hours, from 2 PM to 4 PM. Section 4.1 summarizes the ex post results for this event.

2.3 Overview of PG&E's BIP Program

Customers can enroll in PG&E's BIP program 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 120 event hours per calendar year. A curtailment event may be called under BIP at any time during the year.

As May 2012, there were 230 accounts[8] enrolled in PG&E's BIP program. Since the end of 2010, the number of participants has grown by 41 accounts. Table 2-2 shows the distribution of service accounts by industry grouping. As in SCE's BIP program, the largest number of accounts comes from the manufacturing sector (38% of the total).

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7 Local capacity area (or LCA) refers to a CAISO-designated load pocket or transmission constrained geographic area for which a utility is required to meet a Local Resource Adequacy capacity requirement. There are currently 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 being in the "Other" LCA region.

8 Officially, PG&E refers to these as "service agreements," but in order to be consistent with the terminology used for SCE and SDG&E, "accounts" is used.

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

Industry	Number of Accounts
Agriculture, Mining & Construction	35
Manufacturing	87
Wholesale, Transport & Other Utilities	45
Retail Stores	31
Offices, Hotels, Finance & Services	17
Schools	2
Institutional/Government	13
Total	**230**

Table 2-3 shows the distribution of PG&E BIP accounts across LCAs within PG&E's service area. Most BIP participation comes from the Other and Greater Bay Area LCAs.

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

Industry	Number of Accounts
Greater Bay Area	60
Greater Fresno	23
Humboldt	5
Kern	21
Northern Coast	26
Other	74
Sierra	11
Stockton	10
Total	**230**

PG&E expects enrollment in its BIP program to increase over the next few years. Enrollment peaks at 265 participants throughout 2015 and 2016 and then decreases gradually to 248 participants at the end of the ex ante forecast period (2022).

There were two events for PG&E's BIP program in 2011. The system-wide test event occurred on September 7 and lasted for two hours, from 3 PM to 5 PM. In addition to this system-wide test event, PG&E called an actual, localized event on March 11 for the nine participants in group 8 who are located in the Humboldt region. This was a short event lasting from 7:35 AM to 8:08 AM, as a result of the tsunami warning for the coastal areas of California and Oregon and the Humboldt Bay Generation Station shutdown. The ex post analysis for PG&E, presented in Section 5, pertains to these two events.

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. Currently, SDG&E offers two options that vary with respect to the notification period, number and duration of allowed events and incentive payments:

- BIP-A (Option A): Requires load reduction response within 30 minutes. Incentive payments are $7/kW. The maximum event length is 4 hours per day and the maximum number of events is 10 per month and 120 hours per calendar year; and
- BIP-B (Option B): Requires load reduction response within three hours. Incentive payments are $3/kW. The maximum event length is 3 hours per day and the maximum number of events is 10 per month and 90 hours per calendar year.

All SDG&E BIP customers are currently in Option A and Option B may be discontinued at the end of 2012. 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. In October 2010, SDG&E added customers to BIP for the first time in over a year. 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. Recently, a few customers dropped out of the program and as of May 2012, enrollment was at 17 customers. The current distribution of accounts by industry is shown in Table 2-4. There is only one LCA in SDG&E's service territory.

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

Industry	Number of Accounts
Agriculture, Mining & Construction	2
Manufacturing	6
Wholesale, Transport & Other Utilities	1
Retail Stores	5
Offices, Hotels, Finance & Services	3
Schools	0
Institutional/Government	0
Total	**17**

SDG&E plans to increase enrollment in its BIP program over the next few years. In May 2013, SDG&E BIP enrollment is expected to equal 51 participants and 105 in December 2014. Afterwards, enrollment is assumed to remain constant until the end of the ex ante forecast period (2022).

There was one event held for SDG&E's BIP program in 2011. That event occurred on August 18 and lasted for four hours for option A customers (12 PM to 4 PM) and three hours for option B customers (3 PM to 6 PM). Section 6 presents the ex post analysis for the 2011 SDG&E BIP event.

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 utility and Section 7 contains recommendations for improving the program. All of the required ex post and ex ante hourly load impact tables are included in the electronic appendices.

3 Methodology

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

3.1 Model Development

For demand response resources that have numerous events, regression analysis can be used to estimate the typical (absolute or percentage) load reduction associated with events as a function of event-day conditions (e.g., weather, day-of-week, etc.). These regression models can then be used to predict either ex ante or ex post impacts as a function of the conditions that occurred on those historical days or that are expected to occur on future days on which program events are most likely to be called.

With DR resources for which there is little event history like BIP, this regression-based method cannot be used to predict load reductions because there is not enough empirical event data for estimating the impact coefficients. However, for ex ante load impact estimation purposes, regression analysis can be used to predict the reference load (i.e., the load that would occur in the absence of a program event), and the expected load reductions from those customers given their FSL. For ex post load impact estimation purposes, regression analysis can be used to predict the reference load for the historical event day; the actual metered load for that day can be subtracted from the reference load to estimate the load impact.

For ex ante analysis, the estimated load reduction for BIP is 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 load is estimated using the regression model discussed below. 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. Although the number of events is too small to be used in a regression to predict the load with DR, it can be used to adjust load relative to the FSL. By subtracting the estimated load with DR from the reference load, the ex ante load impact can be estimated.

The regression models used to predict reference loads were developed with the primary goal of accurately predicting the average customer load given time-of-day, day-of-week, month and temperature. Given that all BIP customers are on TOU rates, rate-period variables were also included in the model specification. The estimated models were based on one year of hourly load data for each customer. Individual regressions with all 24 hours included were run for each customer.

The dependent variable in the regression model was the kW load in each hourly interval for each participant. The regression model contained hundreds of 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 when the underlying TOU rates changed during the day and season were also included to capture the change in load due to price variation. The regression model is as follows:

$$
\begin{aligned}
kW_t = {} & A + B \times SummerOn_t + C \times SummerMid_t + D \times SummerOff_t + E \times WinterMid_t \\
& + \sum_{i=1}^{24}\sum_{j=1}^{5} F_{ij} \times Hour_i \times DayType_j + \sum_{i=1}^{24}\sum_{j=1}^{12} G_{ij} \times Hour_i \times Month_j + \\
& + \sum_{i=1}^{24} H_{ij} \times Hour_i \times TotalCDH_t + \sum_{i=1}^{24} I_{ij} \times Hour_i \times TotalCDHsqr_t \\
& + \sum_{i=1}^{24} J_{ij} \times Hour_i \times TotalHDH_t + \sum_{i=1}^{24} K_{ij} \times Hour_i \times TotalHDHsqr_t \\
& + \sum_{i=1}^{24} L_i \times Hour_i \times Other\_Eventday_t \\
& + \sum_{i=1}^{24}\sum_{j=1}^{2} M_{ij} \times Hour_i \times BIP\_Eventday_j + e_t
\end{aligned}
$$

Table 3-1:
Variable Descriptions

Variable	Description
kW_t	hourly BIP customer load at time t
A	estimated constant term
B through M_{ij}	estimated parameters
$SummerOn_t$, $SummerMid_t$, $SummerOff_t$ and $WinterMid_t$	binary variables that indicate which TOU rate block is in effect for each hour
$Hour_i$	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
$DayType_j$	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
$TotalCDH_t$	total number of cooling degree hours (base 70) per day
$TotalCDHsqr_t$	total number of cooling degree hours per day squared
$TotalHDH_t$	total number of heating degree hours (base 70) per day
$TotalHDHsqr_t$	total number of heating degree hours squared
$Other\_Eventday_t$	binary variable for event days from other DR programs
$BIP\_Eventday_j$	binary variable representing each BIP event day;[9]
e_t	error term

[9] SCE and SDG&E had one event during the time period included in the estimation, whereas some PG&E BIP participants had two events.

Load was significantly lower in recent years for many BIP customers due to changes in overall economic conditions. If these conditions were not accounted for in the model, there would be a downward bias in the forecasted reference load for the ex ante analysis, assuming that economic growth rebounds from recent years. Each utility had its own assumptions concerning the economic recovery and its effect on BIP load in the ex ante analysis:

- SCE: BIP load is assumed to increase by 1.5% per year from 2012 through 2014 and then reach a steady state from 2015 through 2022;
- PG&E: BIP load is assumed to increase by 1.3% per year from 2012 through 2017 and then *decrease* by 0.1% per year from 2018 through 2022; and
- SDG&E: BIP load is assumed to remain the same. With so few customers in the program, it is difficult to determine whether a customer experienced a decline in load due to the economic downturn or had a permanent change in their business practices.

For SCE, the load growth assumption is based on an analysis of recent trends in aggregate BIP load. PG&E used its internal economic forecast for large business customers to project how BIP load will change from 2012 through 2022.

3.2 Model Accuracy and Validity Assessment

Although regressions were run for each individual customer in the BIP program, what matters most is that the reference loads for all customers combined, or for selected groups of customers (e.g., industry types, 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.

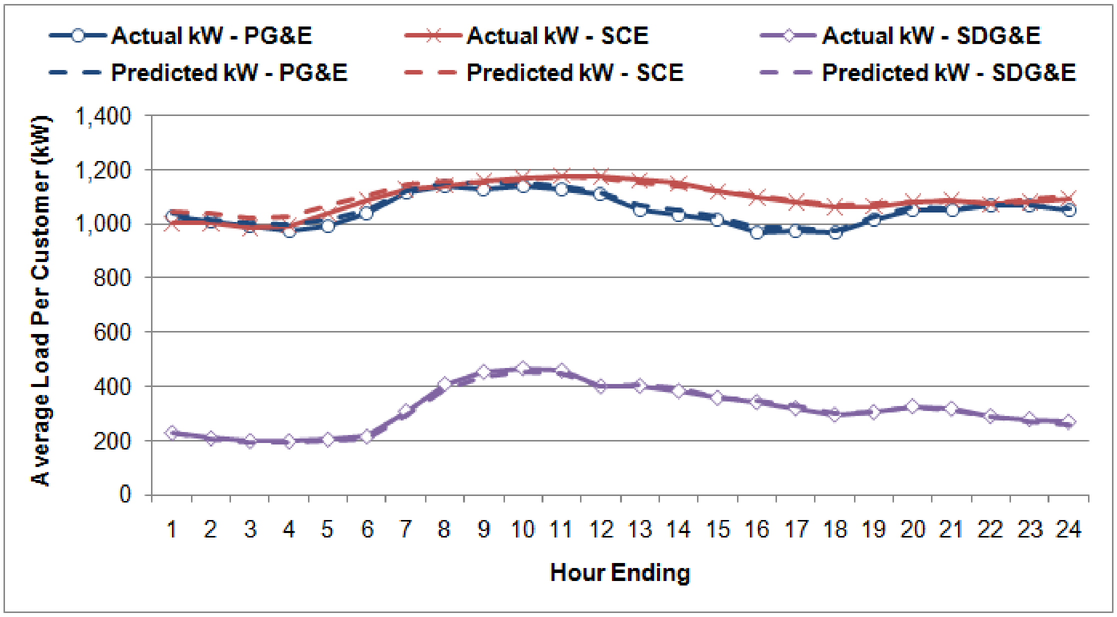
3.2.1 Out-of-Sample Validation

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 3-1 shows the results of the out-of-sample validation for 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 did not exceed 5.3% in any hour for each utility. More importantly, the percentage error is low during the afternoon when events are most likely to be called. Between 1 PM and 6 PM, the SCE model very slightly over predicts by 0.1%, the PG&E model over predicts by less than 1.4% and the SDG&E model is also over by 2.2%. Considering that BIP customers typically drop more than 70% of their load during events, an error up to 2.2% will have little effect on the accuracy of the load impact estimates.

Figure 3-1:
Actual v. Predicted Average Load by Utility
Out-of-Sample Validation for Top 9 System Load Days[10]



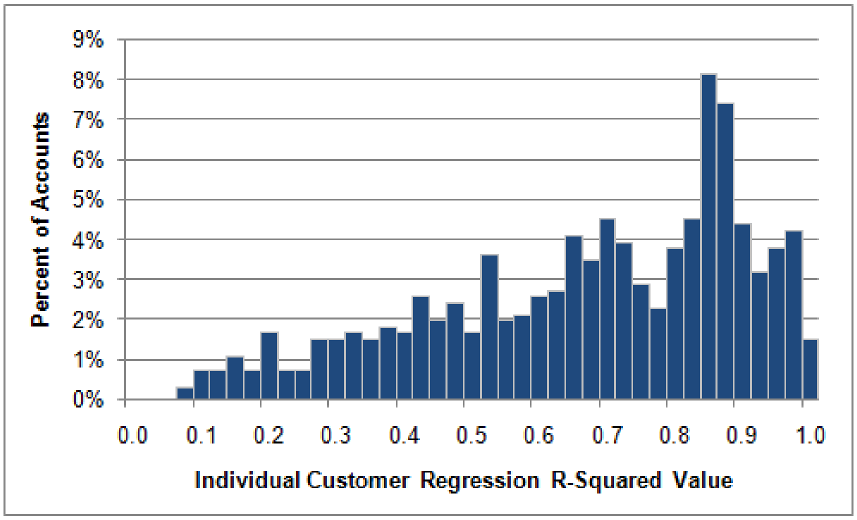
3.2.2 Goodness of Fit Measures

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.

[10] Note that there are two lines for each utility 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 utility is provided in Appendix A.

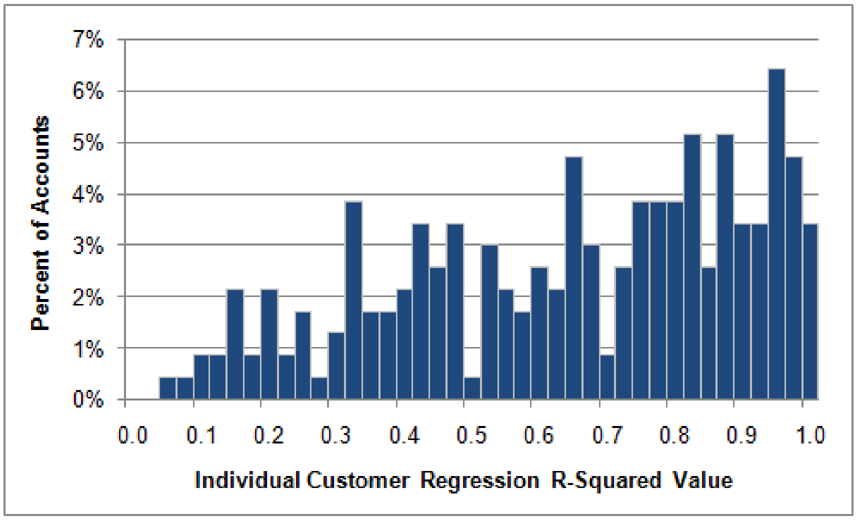
Figure 3-2 shows the distribution of R-squared values from the individual customer regressions for SCE BIP customers. Roughly half of the individual customer regressions had R-squared values above 0.7, which suggests that the model predicts well for most SCE BIP customers. The lower one-third of all individual regressions had R-squared statistics up to 0.6.

Figure 3-2:
Distribution of R-squared Values from Individual Regressions for SCE BIP Customers



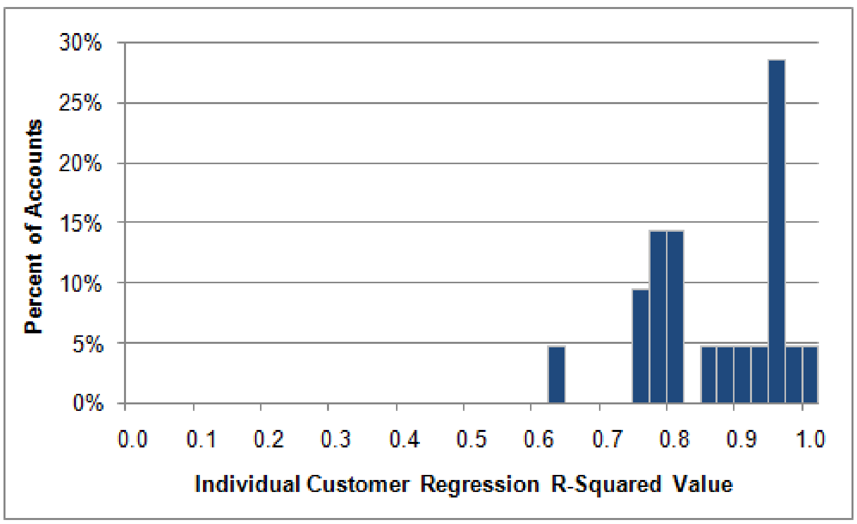
For PG&E BIP customers, the distribution of R-squared values from the individual customer regressions is more variable, as shown in Figure 3-3. About 69% of the individual customer regressions had R-squared values above 0.5. This result suggests that the model explains most of the variation in load for the majority of PG&E BIP customers. The lower one-third of all PG&E individual regressions had R-squared statistics below 0.5. The difference in the distribution of R-squared values between the utilities is primarily a function of the difference in industry mix. PG&E has a relatively large portion of BIP customers in the wholesale, transport & other utilities segment, which has load that is more difficult to explain.

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



As shown in Figure 3-4, the model has relatively high R-squared values for SDG&E BIP customers. All individual customer regressions have an R-squared value above 0.6.

Figure 3-4:
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:[11]

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

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 utility. For all customers, SCE and PG&E have an aggregate R-squared value of 0.7 and 0.78, which means that the model explains 70% and 78% of variation in aggregate BIP load for each utility. As suggested by the histograms above, SDG&E BIP customers have a higher R-squared of 0.9. Retail stores have the highest aggregate R-squared value for each utility, ranging from 0.96 for SCE to 0.99 for PG&E. In general, customers in the wholesale, transport & other utilities segment have usage that is relatively more difficult to explain, which is why their aggregate R-squared value is relatively low.

Table 3-3:
Aggregate R-Squared Values by Industry and Utility

Industry	SCE	PG&E	SDG&E
Agriculture, Mining & Construction	0.48	0.72	
Manufacturing	0.66	0.74	0.88
Wholesale, Transport & Other Utilities	0.37	0.62	
Retail Stores	0.96	0.99	0.98
Offices, Hotels, Finance & Services	0.88	0.90	0.83
Schools	0.93		
Institutional/Government	0.93	0.95	
All Customers	**0.70**	**0.78**	**0.90**

[11] 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 is presented in order to avoid the complication of tracking the number of observations and parameters from each individual regression.

Table 3-4 shows the aggregate R-Squared values by LCA. The explained variation varies from 42% to 90% across LCAs. Only 2 of the LCAs have an R-squared value below 0.6 – SCE's Outside LA Basin LCA (0.46) and PG&E's Kern LCA (0.42). As shown in Table 3-3, the model has a relatively low R-squared value for agriculture, mining & construction and wholesale, transport & other utilities customers. These two industries comprise 48% and 55% of the customer mix in the Outside LA Basin and Kern LCAs, respectively, which explains why the R-squared is relatively low.

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

Utility	Local Capacity Area	R-Squared
SCE	LA Basin	0.71
	Outside LA Basin	0.46
	Ventura	0.60
PG&E	Greater Bay Area	0.85
	Greater Fresno	0.80
	Humboldt	0.65
	Kern	0.42
	Northern Coast	0.84
	Other	0.68
	Sierra	0.87
	Stockton	0.79
SDG&E	San Diego	0.90

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 the ex ante results to adjust for over/under performance. 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 to 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 in the SCE and PG&E ex ante analysis. Therefore, a customer in a given industry is assumed to perform similar to the recent historical performance of customers in its industry. The SDG&E ex ante analysis focuses on over/under performance at the program level because there are so few customers in each industry category. Therefore, SDG&E BIP customers are assumed to perform similar to the recent historical performance of the overall program. 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 tests events), we only have historical performance data for one to three BIP events for most BIP program participants. Furthermore, this analysis does not consider the performance data of customers on interruptible programs that existed prior to BIP. As such, conclusions about such customer's performance should not be drawn from this particular analysis.

The over/under performance analysis is conducted separately for each utility in this year's evaluation. Previously, 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 applied test event protocols that simulate peaking conditions, each utility has its own historical event data to incorporate into the ex ante analysis. Considering that each utility now has recent data for events under these conditions, it is possible to estimate over/under performance based on utility-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 systemwide BIP event in the near future, that data can be pooled with the recent test event data for each utility 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 systemwide BIP event for SCE and PG&E in 2006.

4 SCE Load Impact Analysis

This section includes 2011 ex post load impact estimates and 2012-2022 ex ante load impact estimates for SCE's BIP program. The discussion of load impacts provided below focuses on the 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 appendices titled, “SCE 2011 BIP Ex Post Load Impact Tables" and "SCE 2011 BIP Ex Ante Load Impact Tables."

4.1 Ex Post Load Impact Estimates

SCE held a system-wide test event for BIP on September 21 from 2 PM to 4 PM, which was the first SCE BIP event since 2009. Overall, 661 customers participated in the event, of which 20% were participating in a BIP event for the first time. Although participants are required to respond within 15 to 30 minutes for actual BIP events, 24-hour advance notice was provided for this test event. In the 24-hour advance notice, the exact timing of the event was not provided. SCE started providing final notification of the event at 2 PM on September 21 and customers were required to curtail load within 15 or 30 minutes of receiving notification, depending on their BIP program option. Customers were instructed to curtail load until 4 PM.

Figure 4-1 shows the average load impact per customer in each hour on September 21. As seen, the average load drop over the two-hour event period was 790 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 nearly 11% 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 522 MW. This represents nearly a 70% reduction relative to the reference load of 751 MW. From 3 PM to 4 PM, aggregate load lowered to 149 MW and customers provided 91% of the expected load reduction given the aggregate FSL of 97 MW.

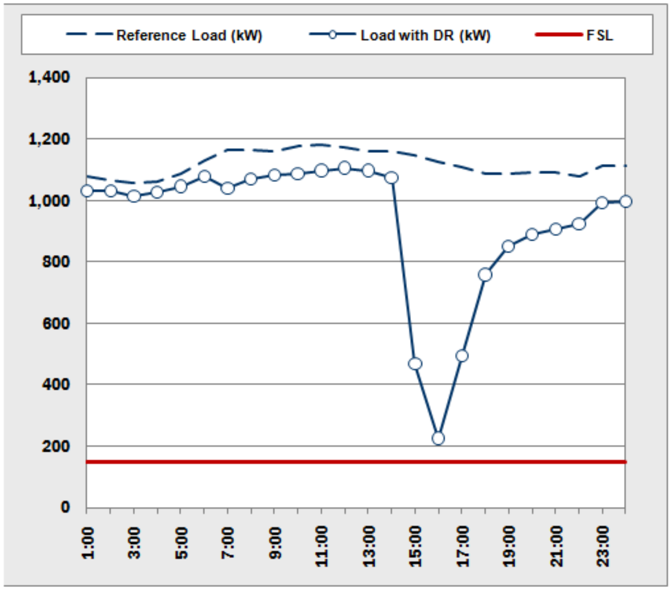
Figure 4-1:
Average Ex Post Load Impact (kW) per Participant for SCE BIP Event (September 21, 2011)

TABLE 1: Menu options

Type of Results	Average Enrolled Account
Event	Wednesday, September 21, 2011
Customer Characteristic	All Customers

TABLE 2: Output

Number of Accounts	661
Average FSL (kW)	146.6



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	1080.0	1029.4	50.7	62.7	5.9	32.3	50.7	69.0	95.4
2:00	1066.7	1029.9	36.8	62.0	-7.9	18.5	36.8	55.1	81.5
3:00	1054.5	1013.0	41.5	61.5	-3.3	23.2	41.5	59.8	86.3
4:00	1059.7	1026.2	33.5	60.9	-11.5	15.1	33.5	51.9	78.4
5:00	1085.2	1045.1	40.1	60.7	-4.8	21.8	40.1	58.5	85.0
6:00	1128.9	1077.3	51.5	60.3	6.6	33.2	51.5	69.9	96.4
7:00	1163.5	1040.2	123.3	61.1	78.4	104.9	123.3	141.7	168.2
8:00	1162.7	1068.3	94.4	63.6	49.6	76.0	94.4	112.7	139.2
9:00	1160.0	1083.1	76.9	67.6	32.8	58.9	76.9	95.0	121.1
10:00	1174.8	1085.9	88.8	72.6	44.6	70.7	88.8	106.9	133.0
11:00	1179.0	1097.0	82.0	76.4	37.9	64.0	82.0	100.1	126.1
12:00	1171.8	1105.6	66.2	78.0	22.2	48.2	66.2	84.1	110.1
13:00	1160.7	1097.2	63.5	79.5	19.5	45.5	63.5	81.5	107.4
14:00	1157.9	1074.0	83.9	80.0	40.0	65.9	83.9	101.9	127.8
15:00	1146.4	467.5	678.9	79.0	634.9	660.9	678.9	696.9	722.9
16:00	1125.9	224.8	901.2	77.6	857.2	883.2	901.2	919.1	945.1
17:00	1108.0	492.7	615.2	74.9	571.2	597.2	615.2	633.2	659.2
18:00	1086.5	758.4	328.1	72.1	284.1	310.1	328.1	346.1	372.1
19:00	1087.2	849.4	237.9	69.5	193.8	219.8	237.9	255.9	281.9
20:00	1089.4	888.8	200.6	68.0	156.6	182.6	200.6	218.7	244.7
21:00	1091.0	905.6	185.4	66.4	141.1	167.3	185.4	203.6	229.7
22:00	1078.9	922.6	156.3	65.5	112.0	138.2	156.3	174.4	200.6
23:00	1113.8	991.8	122.0	64.5	77.2	103.7	122.0	140.3	166.8
0:00	1113.6	996.1	117.6	64.1	72.9	99.3	117.6	135.8	162.2
	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	26,845.9	22,369.7	4,476.2	60.1	4258.8	4387.3	4476.2	4565.2	4693.6

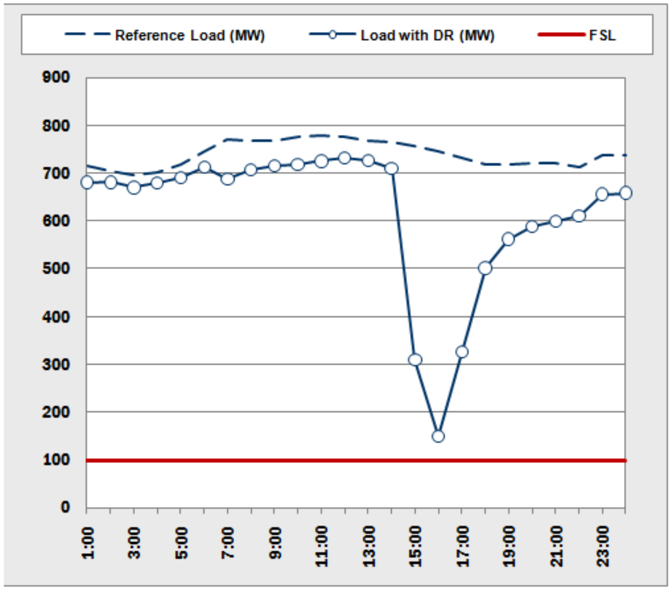
Figure 4-2:
Aggregate Ex Post Load Impact (MW) for SCE BIP Event (September 21, 2011)

TABLE 1: Menu options

Type of Results	Aggregate
Event	Wednesday, September 21, 2011
Customer Characteristic	All Customers

TABLE 2: Output

Number of Accounts	661
Aggregate FSL (MW)	96.9



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	713.9	680.4	33.5	62.7	3.9	21.4	33.5	45.6	63.1
2:00	705.1	680.7	24.3	62.0	-5.2	12.2	24.3	36.4	53.9
3:00	697.0	669.6	27.4	61.5	-2.2	15.3	27.4	39.5	57.0
4:00	700.4	678.3	22.1	60.9	-7.6	10.0	22.1	34.3	51.8
5:00	717.3	690.8	26.5	60.7	-3.1	14.4	26.5	38.7	56.2
6:00	746.2	712.1	34.1	60.3	4.4	21.9	34.1	46.2	63.8
7:00	769.1	687.6	81.5	61.1	51.8	69.3	81.5	93.7	111.2
8:00	768.5	706.1	62.4	63.6	32.8	50.3	62.4	74.5	92.0
9:00	766.8	715.9	50.9	67.6	21.7	38.9	50.9	62.8	80.0
10:00	776.5	717.8	58.7	72.6	29.5	46.8	58.7	70.7	87.9
11:00	779.3	725.1	54.2	76.4	25.1	42.3	54.2	66.1	83.4
12:00	774.5	730.8	43.7	78.0	14.7	31.8	43.7	55.6	72.8
13:00	767.2	725.2	42.0	79.5	12.9	30.1	42.0	53.8	71.0
14:00	765.4	709.9	55.5	80.0	26.4	43.6	55.5	67.3	84.5
15:00	757.8	309.0	448.7	79.0	419.7	436.8	448.7	460.6	477.8
16:00	744.2	148.6	595.7	77.6	566.6	583.8	595.7	607.5	624.7
17:00	732.4	325.7	406.7	74.9	377.6	394.8	406.7	418.6	435.8
18:00	718.2	501.3	216.9	72.1	187.8	205.0	216.9	228.8	245.9
19:00	718.7	561.4	157.2	69.5	128.1	145.3	157.2	169.1	186.3
20:00	720.1	587.5	132.6	68.0	103.5	120.7	132.6	144.5	161.7
21:00	721.1	598.6	122.6	66.4	93.3	110.6	122.6	134.5	151.8
22:00	713.1	609.8	103.3	65.5	74.0	91.3	103.3	115.3	132.6
23:00	736.2	655.6	80.6	64.5	51.0	68.5	80.6	92.8	110.2
0:00	736.1	658.4	77.7	64.1	48.2	65.6	77.7	89.8	107.2
	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	17,745.2	14,786.4	2,958.8	60.1	2815.1	2900.0	2958.8	3017.6	3102.5

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 for all customers were primarily driven by participants in the manufacturing sector, which accounted for 56.6% of event participants and 64.9% of the aggregate load reduction. Manufacturing customers also had the highest performance, providing 84.4% of the expected load reduction. The agriculture, mining & construction segment was the only other industry group to provide more than 7% of the aggregate load reduction. Although customers in this segment accounted for less than 10% of event participants, they comprised 19.3% of the aggregate load reduction because agriculture, mining & construction customers had the highest reference load per customer (over 2.1 MW) and largest percent load reduction (76.6%).

Table 4-1:
Average Customer Load Impact by Industry for September 21, 2011 SCE Event

Industry	Number of Customers	Reference Load (kW)	Load with DR (kW)	Load Reduction (kW)	Average FSL (kW)	Performance (%)
Agriculture, Mining & Construction	62	2,119.6	496.3	1,623.3	136.3	81.8
Manufacturing	374	1,246.4	340.5	905.9	172.5	84.4
Wholesale, Transport & Other Utilities	67	772.4	242.2	530.2	107.0	79.7
Retail Stores	39	617.8	357.8	260.0	83.9	48.7
Offices, Hotels, Finance & Services	43	836.3	437.4	399.0	232.0	66.0
Schools	67	532.9	272.8	260.1	22.9	51.0
Institutional/Government	9	659.7	381.4	278.4	224.4	64.0
All Customers	**661**	**1,136.2**	**346.2**	**790.0**	**146.6**	**79.8**

Table 4-2:
Aggregate Load Impact by Industry for September 21, 2011 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	62	131.4	30.8	100.6	76.6	19.3
Manufacturing	374	466.1	127.3	338.8	72.7	64.9
Wholesale, Transport & Other Utilities	67	51.8	16.2	35.5	68.6	6.8
Retail Stores	39	24.1	14.0	10.1	42.1	1.9
Offices, Hotels, Finance & Services	43	36.0	18.8	17.2	47.7	3.3
Schools	67	35.7	18.3	17.4	48.8	3.3
Institutional/Government	9	5.9	3.4	2.5	42.2	0.5
All Customers	**661**	**751.0**	**228.8**	**522.2**	**69.5**	**100.0**

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 (682.5 kW), this LCA accounted for 72.7% of the aggregate load reduction because 556 of 661 event participants were located there. Customers in the Outside LA Basin LCA provided the largest average load reduction per participant (2,357,8 kW) and highest percent load reduction (80.5%).

Table 4-3:
Average Customer Load Impact by Local Capacity Area for September 21, 2011 SCE Event

Local Capacity Area	Number of Customers	Reference Load (kW)	Load with DR (kW)	Load Reduction (kW)	Average FSL (kW)	Performance (%)
LA Basin	556	1,019.2	336.8	682.5	145.3	78.1
Outside LA Basin	24	2,927.4	569.6	2,357.8	291.9	89.5
Ventura	81	1,408.1	344.3	1,063.8	112.6	82.1
All Customers	**661**	**1,136.2**	**346.2**	**790.0**	**146.6**	**79.8**

Table 4-4:
Aggregate Load Impact by Local Capacity Area for September 21, 2011 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	556	566.7	187.3	379.4	67.0	72.7
Outside LA Basin	24	70.3	13.7	56.6	80.5	10.8
Ventura	81	114.1	27.9	86.2	75.5	16.5
All Customers	**661**	**751.0**	**228.8**	**522.2**	**69.5**	**100.0**

4.2 Over/Under Performance Analysis

For SCE's over/under performance analysis, data for the 2011 SCE test event was used. Data for multiple years was not pooled together, as in PG&E's over/under performance analysis, because SCE did not call a BIP event in 2010 and in 2009, the systemwide test event was called at the end of the summer (September 23) without any forewarning of the test. Although this 2009 event is useful for understanding BIP demand response in sudden, unexpected emergencies, it is not applicable to the over/under performance analysis that is incorporated into the ex ante load impact estimates. Although the notification lead time for BIP is much shorter than the 24-hour advance notice that SCE customers received for the 2011 test, this event simulated a situation when there are generation supply shortages during a long heat wave and customers expect a BIP event, which is the most applicable scenario for the ex ante analysis.

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 91.8% of the expected load reduction given their FSL during the event. This performance level differs from the reported performance in Table 4-1 and Table 4-3 because it accounts for the specific 15-minute time intervals for which each individual customer was required to respond. As discussed above, SCE started providing final notification at 2 PM and customers were required to curtail load within 15 or 30 minutes of receiving notification, depending on their BIP program option. This over/underperformance analysis used the 15-minute interval data and after identifying the specific intervals for which each individual customer was required to respond, participants achieved 91.8% performance overall. This is similar to the reported performance for the final hour of the 2011 event (91%) because nearly every customer was required to respond by 3 PM and were instructed to curtail load until 4 PM.

Performance varies substantially by industry. Customers in the agriculture, mining & construction and manufacturing segments underperform slightly during the event, which drives much of the overall result for all customers.. Retail stores and schools generally under perform, providing less than 65% 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. As a result, SCE 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 4-5:
SCE BIP Over/Under Performance Percentages by Industry and Event Hour
2011 SCE Systemwide BIP Event

Industry	N	% Over/Under Performance		
		Hour Before Event	During Event	Hour After Event
Agriculture, Mining & Construction	62	41.5	97.8	80.2
Manufacturing	374	47.5	95.3	67.0
Wholesale, Transport & Other Utilities	67	43.1	91.0	52.3
Retail Stores	39	30.7	62.3	29.4
Offices, Hotels, Finance & Services	43	37.0	76.1	43.6
Schools	67	29.4	64.6	41.3
Institutional/Government	9	18.3	86.0	31.8
All Customers	**661**	**44.1**	**91.8**	**64.2**

4.3 Ex Ante Load Impact Estimates

SCE projects that BIP enrollment will remain constant throughout the ex ante forecast period (2012-2022). Although enrollment does not change, ex ante load impact estimates increase slightly over time due to load growth. As discussed in Section 3.1, SCE BIP load is assumed to increase by 1.5% per year from 2012 through 2014 and then reach a steady state from 2015 through 2021. This 1.5% annual increase is applied to the estimated reference load, which in turn leads to a proportional increase in load impacts.

Figures 4-3 and 4-4 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 2015. Impacts are reported for 2015 because it is the year in which BIP load growth reaches a steady state through 2022. For a 1-in-2 typical event day, the estimated load impact for the average participant is 932.7 kW from 1 PM to 6 PM. This represents a 80.8% impact relative to the average reference load of 1,154.9 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.

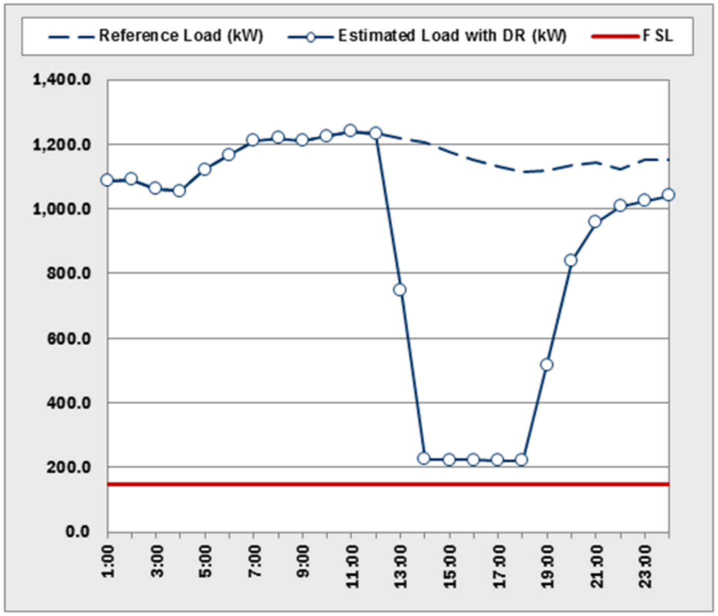
Figure 4-3:
SCE BIP Average Load Impact (kW) per Customer in 2015
for a Typical Event Day Based on 1-in-2 Year Weather Conditions

TABLE 1: Menu options

Type of Results	Average Enrolled Account
Weather Year	1-in-2
Forecast Year	2015-2022
Day Type	Typical Event Day
Customer Characteristic	All Customers

TABLE 2: Output

Number of Accounts	656
Average FSL (kW)	146.2
Proxy Date	N/A
Average Load Impact (kW) (1-6pm)	932.7
% Load Impact (1-6pm)	80.8%



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	1086.9	1086.9	0.0	69.2	-44.6	-18.2	0.0	18.2	44.6
2:00	1090.5	1090.5	0.0	68.1	-44.7	-18.3	0.0	18.3	44.7
3:00	1062.1	1062.1	0.0	66.9	-44.3	-18.1	0.0	18.1	44.3
4:00	1054.2	1054.2	0.0	66.3	-44.2	-18.1	0.0	18.1	44.2
5:00	1122.4	1122.4	0.0	65.5	-44.6	-18.3	0.0	18.3	44.6
6:00	1167.9	1167.9	0.0	65.0	-44.6	-18.3	0.0	18.3	44.6
7:00	1211.0	1211.0	0.0	65.5	-44.7	-18.3	0.0	18.3	44.7
8:00	1218.3	1218.3	0.0	68.9	-44.4	-18.2	0.0	18.2	44.4
9:00	1211.5	1211.5	0.0	74.5	-44.2	-18.1	0.0	18.1	44.2
10:00	1225.8	1225.8	0.0	79.7	-44.2	-18.1	0.0	18.1	44.2
11:00	1240.1	1240.1	0.0	84.0	-44.2	-18.1	0.0	18.1	44.2
12:00	1232.9	1231.3	1.6	87.2	-42.4	-16.4	1.6	19.6	45.7
13:00	1217.4	749.2	468.2	89.5	424.2	450.2	468.2	486.2	512.2
14:00	1204.3	224.3	980.1	91.2	936.1	962.1	980.1	998.1	1024.1
15:00	1174.7	222.6	952.1	91.8	908.2	934.2	952.1	970.1	996.1
16:00	1151.0	222.1	928.9	91.9	885.0	910.9	928.9	946.8	972.7
17:00	1131.9	221.4	910.5	90.8	866.7	892.6	910.5	928.4	954.3
18:00	1112.3	220.6	891.7	88.6	847.9	873.8	891.7	909.6	935.5
19:00	1116.9	517.5	599.4	85.4	555.7	581.5	599.4	617.4	643.2
20:00	1133.2	840.4	292.8	81.6	248.9	274.9	292.8	310.8	336.7
21:00	1142.9	957.0	185.9	77.6	141.8	167.9	185.9	203.9	230.0
22:00	1122.4	1006.7	115.7	75.1	71.8	97.7	115.7	133.7	159.6
23:00	1153.3	1025.1	128.2	73.2	83.6	109.9	128.2	146.4	172.8
0:00	1150.8	1041.6	109.2	71.3	65.0	91.1	109.2	127.3	153.4
	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	27,734.6	21,170.3	6,564.3	213.3	6347.8	6475.7	6564.3	6652.9	6780.8

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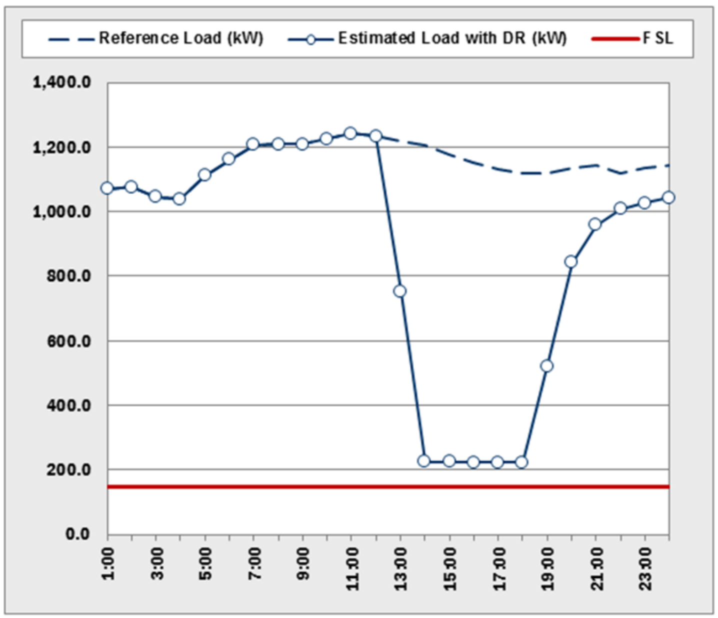
Figure 4-4:
SCE BIP Average Load Impact (kW) per Customer in 2015
for a Typical Event Day Based on 1-in-10 Year Weather Conditions

TABLE 1: Menu options

Type of Results	Average Enrolled Account
Weather Year	1-in-10
Forecast Year	2015-2022
Day Type	Typical Event Day
Customer Characteristic	All Customers

TABLE 2: Output

Number of Accounts	656
Average FSL (kW)	146.2
Proxy Date	N/A
Average Load Impact (kW) (1-6pm)	932.7
% Load Impact (1-6pm)	80.7%



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	1069.9	1069.9	0.0	76.1	-46.4	-19.0	0.0	19.0	46.4
2:00	1076.8	1076.8	0.0	74.6	-46.5	-19.0	0.0	19.0	46.5
3:00	1045.1	1045.1	0.0	73.6	-45.9	-18.8	0.0	18.8	45.9
4:00	1038.9	1038.9	0.0	72.8	-45.8	-18.8	0.0	18.8	45.8
5:00	1111.1	1111.1	0.0	72.2	-46.5	-19.0	0.0	19.0	46.5
6:00	1160.0	1160.0	0.0	71.8	-46.5	-19.0	0.0	19.0	46.5
7:00	1206.0	1206.0	0.0	72.0	-46.8	-19.1	0.0	19.1	46.8
8:00	1209.5	1209.5	0.0	74.6	-45.9	-18.8	0.0	18.8	45.9
9:00	1209.0	1209.0	0.0	79.0	-45.5	-18.6	0.0	18.6	45.5
10:00	1224.3	1224.3	0.0	83.0	-45.3	-18.6	0.0	18.6	45.3
11:00	1242.0	1242.0	0.0	86.1	-45.5	-18.6	0.0	18.6	45.5
12:00	1235.3	1232.5	2.8	88.5	-42.4	-15.7	2.8	21.3	48.0
13:00	1218.5	751.5	467.0	90.7	421.9	448.6	467.0	485.4	512.1
14:00	1204.6	224.8	979.8	92.3	934.9	961.4	979.8	998.3	1024.8
15:00	1174.4	224.1	950.3	93.0	905.4	931.9	950.3	968.6	995.2
16:00	1150.9	223.0	928.0	92.7	883.2	909.7	928.0	946.3	972.7
17:00	1132.7	222.4	910.3	91.4	865.6	892.0	910.3	928.6	955.0
18:00	1117.0	221.9	895.1	89.1	850.5	876.9	895.1	913.4	939.7
19:00	1117.7	519.3	598.4	85.9	553.8	580.2	598.4	616.7	643.1
20:00	1135.8	842.7	293.2	81.7	248.3	274.8	293.2	311.6	338.1
21:00	1144.9	958.0	186.9	78.1	141.6	168.4	186.9	205.4	232.2
22:00	1119.9	1008.0	111.9	76.0	66.9	93.5	111.9	130.4	157.0
23:00	1135.1	1026.0	109.1	74.3	62.1	89.9	109.1	128.4	156.2
0:00	1141.8	1042.4	99.3	73.2	53.7	80.7	99.3	118.0	145.0
	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	27,621.3	21,089.1	6,532.3	262.6	6309.0	6440.9	6532.3	6623.6	6755.5

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 PM to 6 PM for the typical event day and the April through October monthly peak days and 4 PM 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 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 to 2022 time period, the program is expected to be capable of delivering up to 647.4 MW, which occurs during the April monthly peak under 1-in-10 weather conditions. As a result of load growth, aggregate load impacts for the 1-in-2 typical event day grow from 588.3 MW in 2012 to 611.8 MW in 2015-2022. This percentage growth of 4% from 2012 to 2015 is similar across all of the day types.

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	2012	2013	2014	2015-2022
1-in-2	Typical Event Day	1-6 PM	588.3	598.3	608.4	611.8
	January Peak	4-9 PM	508.1	516.8	525.5	533.7
	February Peak	4-9 PM	568.0	577.5	587.3	595.5
	March Peak	4-9 PM	544.3	553.5	562.8	569.9
	April Peak	1-6 PM	616.6	627.0	637.5	644.6
	May Peak	1-6 PM	607.4	617.7	628.1	634.3
	June Peak	1-6 PM	583.5	593.4	603.5	608.5
	July Peak	1-6 PM	578.8	588.7	598.7	602.9
	August Peak	1-6 PM	588.5	598.4	608.6	612.0
	September Peak	1-6 PM	590.9	600.9	611.1	613.6
	October Peak	1-6 PM	572.2	582.0	591.9	593.5
	November Peak	4-9 PM	559.0	568.5	578.1	578.9
	December Peak	4-9 PM	473.6	481.7	489.9	489.9
1-in-10	Typical Event Day	1-6 PM	588.4	598.3	608.4	611.9
	January Peak	4-9 PM	495.3	503.7	512.2	520.2
	February Peak	4-9 PM	590.0	599.9	610.0	618.5
	March Peak	4-9 PM	592.0	602.0	612.1	619.8
	April Peak	1-6 PM	619.3	629.7	640.3	647.4
	May Peak	1-6 PM	609.5	619.8	630.3	636.4
	June Peak	1-6 PM	588.0	598.0	608.1	613.2
	July Peak	1-6 PM	576.5	586.3	596.3	600.5
	August Peak	1-6 PM	589.5	599.5	609.6	613.0
	September Peak	1-6 PM	590.7	600.6	610.8	613.4
	October Peak	1-6 PM	571.5	581.2	591.1	592.8
	November Peak	4-9 PM	566.5	576.0	585.8	586.6
	December Peak	4-9 PM	466.5	474.5	482.6	482.6

Table 4-7 provides the 2015-2022 average and aggregate load impact estimates by LCA for a typical event day under 1-in-2 weather conditions. The LA Basin LCA provides a 443.9 MW aggregate load impact, which accounts for 72.6% of the total for all customers. The Outside LA Basin LCA has the largest average load impact per customer (3,012.1 kW). As a result, the Outside LA Basin LCA accounts for 12.3% of the total aggregate load impact even though it has less than 4% of the total number of customers. The remaining 15.2% of the total aggregate load impact is located in the Ventura LCA.

Table 4-7:
2015-2022 Average and Aggregate Load Impacts by LCA
Typical Event Day under 1-in-2 Weather Conditions, 1 PM to 6 PM

LCA	Number of Customers	Reference Load (kW)	Load with DR (kW)	Avg. Load Impact (kW)	Aggregate Load Impact (MW)	% of Aggregate Load Impact
LA Basin	551	1,021.1	215.5	805.6	443.9	72.6
Outside LA Basin	25	3,471.8	459.7	3,012.1	75.3	12.3
Ventura	80	1,359.7	195.2	1,164.6	93.2	15.2
All Customers	**656**	**1,154.9**	**222.2**	**932.7**	**611.8**	**100.0**

5 PG&E Load Impact Analysis

This section includes 2011 ex post load impact estimates and 2012-2022 ex ante load impact estimates for PG&E's BIP program. The discussion of load impacts provided below focuses on the 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 appendices titled, "PG&E 2011 BIP Ex Post Load Impact Tables" and "BIP Ex Ante Table Generator."

5.1 Ex Post Load Impact Estimates

The ex post load impact estimates presented first in this section are for PG&E's system-wide BIP test event that occurred on September 7, 2011. That event lasted from 3 PM to 5 PM. It was a test event that included all of the 222 customers that were enrolled in BIP at that time. Figure 5-1 shows the average load impact per customer in each hour on September 7. As seen, the average load drop over the two-hour event period was 827.5 kW. In the hour prior to the event, the average load reduction equaled 366.8 kW, and in the first hour after the event, load was still nearly 450 kW below the reference load.

Figure 5-2 shows the aggregate load impact in each hour of the day. The aggregate load drop during the event period was 183.7 MW. This represents roughly a 83% reduction relative to the reference load of 220.9 MW. On aggregate, customers performed as expected as the event-period load of 37.2 MW was nearly the same as the aggregate FSL of 36.7 MW.

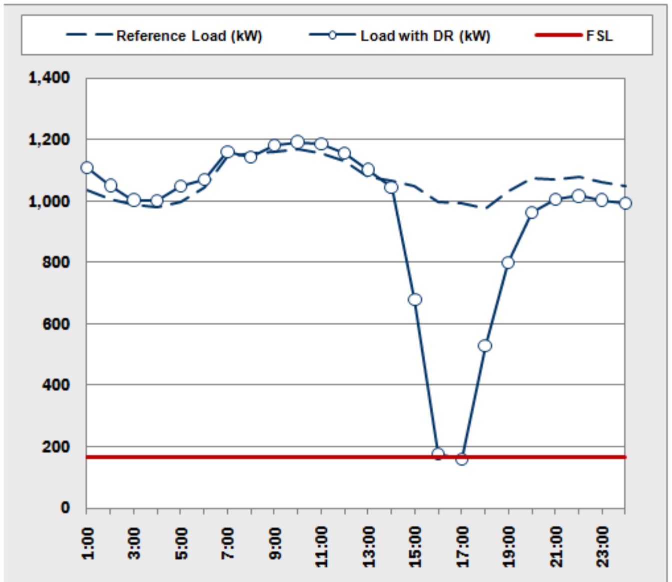
Figure 5-1:
Average Ex Post Load Impact (kW) per Participant for PG&E BIP Event (September 7, 2011)

TABLE 1: Menu options

Type of Results	Average Enrolled Account
Event	Wednesday, September 07, 2011
Customer Characteristic	All Customers

TABLE 2: Output

Number of Accounts	222
Average FSL (kW)	165.5



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	1033.9	1106.7	-72.8	67.3	-124.5	-93.9	-72.8	-51.6	-21.0
2:00	1002.9	1049.7	-46.7	65.9	-98.5	-67.9	-46.7	-25.6	5.0
3:00	988.0	1002.7	-14.8	64.9	-66.4	-35.9	-14.8	6.3	36.8
4:00	978.8	999.4	-20.6	63.5	-72.1	-41.7	-20.6	0.5	30.9
5:00	995.0	1046.8	-51.7	62.6	-103.1	-72.7	-51.7	-30.7	-0.4
6:00	1044.6	1070.1	-25.5	62.3	-77.0	-46.6	-25.5	-4.5	25.9
7:00	1140.6	1159.2	-18.6	61.9	-70.0	-39.6	-18.6	2.4	32.8
8:00	1156.0	1142.4	13.6	63.0	-37.8	-7.4	13.6	34.7	65.1
9:00	1158.8	1182.3	-23.4	67.1	-74.7	-44.4	-23.4	-2.5	27.8
10:00	1169.6	1191.1	-21.5	72.7	-72.8	-42.5	-21.5	-0.6	29.7
11:00	1154.7	1184.9	-30.2	77.6	-81.5	-51.2	-30.2	-9.1	21.2
12:00	1129.1	1156.1	-27.0	82.0	-77.9	-47.8	-27.0	-6.1	24.0
13:00	1076.7	1100.9	-24.2	85.8	-74.9	-45.0	-24.2	-3.5	26.5
14:00	1065.1	1044.1	21.0	89.3	-29.7	0.3	21.0	41.8	71.7
15:00	1046.1	679.3	366.8	91.5	316.3	346.1	366.8	387.5	417.3
16:00	997.7	176.6	821.2	92.3	770.6	800.5	821.2	841.9	871.8
17:00	992.5	158.7	833.8	92.3	783.4	813.2	833.8	854.5	884.3
18:00	976.9	528.6	448.3	91.1	397.7	427.6	448.3	469.0	498.8
19:00	1031.1	799.3	231.7	88.4	181.0	211.0	231.7	252.5	282.5
20:00	1075.1	963.0	112.1	83.0	61.1	91.2	112.1	133.0	163.1
21:00	1069.2	1006.2	63.0	78.4	11.9	42.1	63.0	83.9	114.0
22:00	1079.4	1016.1	63.3	74.9	12.2	42.4	63.3	84.2	114.4
23:00	1061.9	1002.2	59.7	72.1	8.6	38.8	59.7	80.6	110.7
0:00	1048.0	992.7	55.3	70.2	4.1	34.3	55.3	76.2	106.5

	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	25,471.8	22,759.0	2,712.8	191.6	2462.3	2610.3	2712.8	2815.2	2963.2

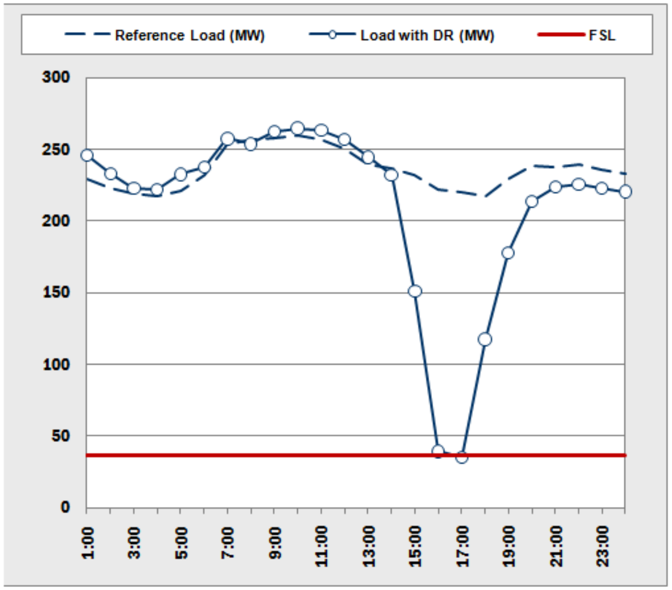
Figure 5-2:
Aggregate Load Impact (MW) for PG&E BIP Event (September 7, 2011)

TABLE 1: Menu options

Type of Results	Aggregate
Event	Wednesday, September 07, 2011
Customer Characteristic	All Customers

TABLE 2: Output

Number of Accounts	222
Aggregate FSL (MW)	36.7



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	229.5	245.7	-16.2	67.3	-27.6	-20.9	-16.2	-11.4	-4.7
2:00	222.7	233.0	-10.4	65.9	-21.9	-15.1	-10.4	-5.7	1.1
3:00	219.3	222.6	-3.3	64.9	-14.7	-8.0	-3.3	1.4	8.2
4:00	217.3	221.9	-4.6	63.5	-16.0	-9.3	-4.6	0.1	6.9
5:00	220.9	232.4	-11.5	62.6	-22.9	-16.1	-11.5	-6.8	-0.1
6:00	231.9	237.6	-5.7	62.3	-17.1	-10.3	-5.7	-1.0	5.7
7:00	253.2	257.3	-4.1	61.9	-15.5	-8.8	-4.1	0.5	7.3
8:00	256.6	253.6	3.0	63.0	-8.4	-1.6	3.0	7.7	14.4
9:00	257.3	262.5	-5.2	67.1	-16.6	-9.9	-5.2	-0.5	6.2
10:00	259.6	264.4	-4.8	72.7	-16.2	-9.4	-4.8	-0.1	6.6
11:00	256.4	263.0	-6.7	77.6	-18.1	-11.4	-6.7	-2.0	4.7
12:00	250.7	256.7	-6.0	82.0	-17.3	-10.6	-6.0	-1.4	5.3
13:00	239.0	244.4	-5.4	85.8	-16.6	-10.0	-5.4	-0.8	5.9
14:00	236.5	231.8	4.7	89.3	-6.6	0.1	4.7	9.3	15.9
15:00	232.2	150.8	81.4	91.5	70.2	76.8	81.4	86.0	92.6
16:00	221.5	39.2	182.3	92.3	171.1	177.7	182.3	186.9	193.5
17:00	220.3	35.2	185.1	92.3	173.9	180.5	185.1	189.7	196.3
18:00	216.9	117.4	99.5	91.1	88.3	94.9	99.5	104.1	110.7
19:00	228.9	177.5	51.4	88.4	40.2	46.8	51.4	56.1	62.7
20:00	238.7	213.8	24.9	83.0	13.6	20.3	24.9	29.5	36.2
21:00	237.4	223.4	14.0	78.4	2.6	9.3	14.0	18.6	25.3
22:00	239.6	225.6	14.1	74.9	2.7	9.4	14.1	18.7	25.4
23:00	235.7	222.5	13.2	72.1	1.9	8.6	13.2	17.9	24.6
0:00	232.7	220.4	12.3	70.2	0.9	7.6	12.3	16.9	23.6
	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	5,654.7	5,052.5	602.2	191.6	546.6	579.5	602.2	625.0	657.8

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. One industry group (schools) is excluded from the tables because it had less than four customers.

Among the six industry groups included in Table 5-1, customers in the agriculture, mining & construction and wholesale, transport & other utilities segments had the highest performance during the event. Both of these industries achieved performance above 100% (i.e., reduced load below their FSL). The performance for retail stores was substantially lower, only providing 9.2% of the expected load reduction. Customers in the manufacturing and wholesale, transport & other utilities segments provided the largest percentage load drop (around 88% of the reference load). In aggregate, the manufacturing sector provided 65.3% of the total load reduction on the event day. This result is consistent with the 2009 and 2010 ex post evaluations, where manufacturing customers provided over 65% of the aggregate load reduction for the past two annual test events.

Table 5-1:
Average Customer Load Impact by Industry for September 7, 2011 PG&E Event

Industry	Number of Customers	Reference Load (kW)	Load with DR (kW)	Load Reduction (kW)	Average FSL (kW)	Performance (%)
Agriculture, Mining & Construction	35	542.1	114.8	427.3	152.9	109.8
Manufacturing	82	1,654.8	191.5	1,463.3	196.0	100.3
Wholesale, Transport & Other Utilities	46	589.0	71.8	517.1	190.5	129.8
Retail Stores	30	216.8	203.2	13.6	69.7	9.2
Offices, Hotels, Finance & Services	14	2,053.5	439.9	1,613.6	296.8	91.9
Institutional/Government	14	261.7	124.6	137.1	22.4	57.3
All Customers	**222**	**995.1**	**167.6**	**827.5**	**165.5**	**99.7**

Table 5-2:
Aggregate Load Impact by Industry for September 7, 2011 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	35	19.0	4.0	15.0	78.8	8.1
Manufacturing	82	135.7	15.7	120.0	88.4	65.3
Wholesale, Transport & Other Utilities	46	27.1	3.3	23.8	87.8	12.9
Retail Stores	30	6.5	6.1	0.4	6.3	0.2
Offices, Hotels, Finance & Services	14	28.7	6.2	22.6	78.6	12.3
Institutional/Government	14	3.7	1.7	1.9	52.4	1.0
All Customers	**222**	**220.9**	**37.2**	**183.7**	**83.2**	**100.0**

Tables 5-3 and 5-4 show the breakdown of load impacts by LCA. Six of the eight LCAs within PG&E's service territory had 21 or fewer accounts enrolled in BIP at the time of the event. Around 35% of all accounts were located in the Other LCA and nearly 29% in the Greater Bay Area LCA. Half of the customers in the manufacturing segment were located in the Other LCA. This concentration of manufacturing customers explains why the average load reduction in the Other LCA was 860 kW higher than in any of the other areas. As a result, the Other LCA accounted for 69.4% of the aggregate load reduction. This result is consistent with the 2009 and 2010 ex post evaluations, where customers in the Other LCA provided around 70% of the aggregate load reduction for the past two annual test events.

Percent load reductions and performance relative to the FSL vary substantially by LCA. Customers in the Humboldt, Other and Sierra LCAs complied with their FSL and provided a percent load reduction of over 90%. In the Kern LCA, customers under performed slightly and provided a 79.3% load reduction. The Greater Fresno LCA was the only area in which performance was significantly below 75%, but these customers were relatively small (average reference load of 322.4 kW), so they did not have much of an impact on the overall ex post results for all customers.

Table 5-3:
Average Customer Load Impact by Local Capacity Area
for September 7, 2011 PG&E Event

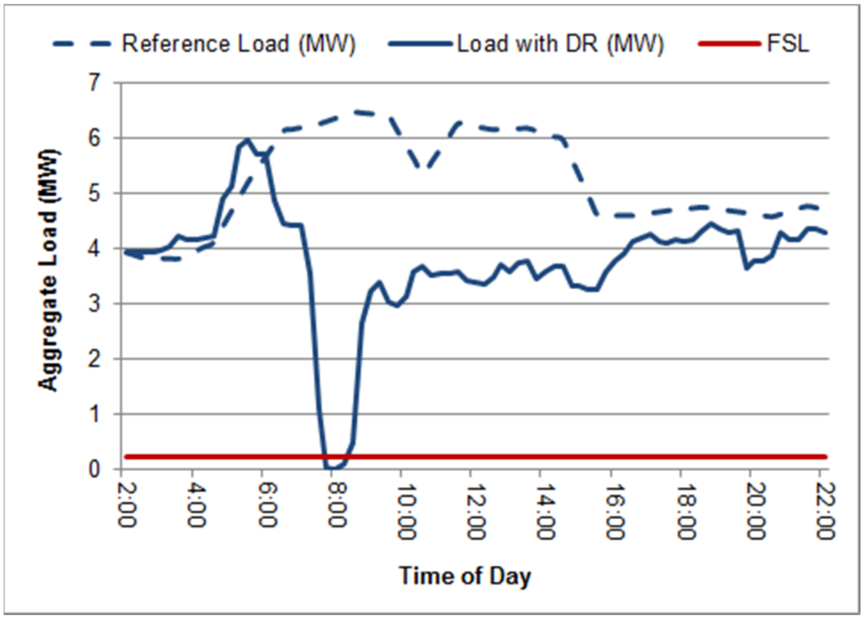
Local Capacity Area	Number of Customers	Reference Load (kW)	Load with DR (kW)	Load Reduction (kW)	Average FSL (kW)	Performance (%)
Greater Bay Area	64	648.3	239.1	409.2	132.2	79.3
Greater Fresno	16	322.4	171.5	150.9	66.8	59.0
Humboldt	7	466.1	18.7	447.4	25.7	101.6
Kern	21	627.8	130.0	497.8	125.0	99.0
Northern Coast	19	379.6	93.4	286.3	70.7	92.7
Other	78	1,808.5	173.2	1,635.3	279.1	106.9
Sierra	8	948.4	25.5	922.9	109.5	110.0
Stockton	9	217.1	90.4	126.7	47.8	74.8
All Customers	**222**	**995.1**	**167.6**	**827.5**	**165.5**	**99.7**

Table 5-4:
Aggregate Load Impact by Local Capacity Area for September 7, 2011 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	64	41.5	15.3	26.2	63.1	14.3
Greater Fresno	16	5.2	2.7	2.4	46.8	1.3
Humboldt	7	3.3	0.1	3.1	96.0	1.7
Kern	21	13.2	2.7	10.5	79.3	5.7
Northern Coast	19	7.2	1.8	5.4	75.4	3.0
Other	78	141.1	13.5	127.6	90.4	69.4
Sierra	8	7.6	0.2	7.4	97.3	4.0
Stockton	9	2.0	0.8	1.1	58.3	0.6
All Customers	**222**	**220.9**	**37.2**	**183.7**	**83.2**	**100.0**

In addition to this system-wide test event, PG&E called an actual, localized event on March 11 for the nine participants in group 8 who are located in the Humboldt region. This was a short event lasting from 7:35 AM to 8:08 AM, as a result of the tsunami warning for the coastal areas of California and Oregon and the Humboldt Bay Generation Station shutdown. Figure 5-3 shows the aggregate reference load, load with DR and FSL for this event. Results in this figure are presented at the 15-minute interval level because the event lasted less than an hour. As shown in the figure, participants fully complied during the event. Aggregate participant load was below the FSL from 7:30 AM to 8:15 AM and the aggregate load impact during that time period was 6.3 MW. In the hourly ex post load impact tables provided as an electronic appendix, the aggregate load reduction is less than 6.3 MW for 7 AM or 8 AM because the event only occurred during a portion of the hour.

Figure 5-3:
Aggregate Reference Load, Load with DR and FSL (MW)
for PG&E's Group 8 BIP Event (March 11, 2011)



5.2 Over/Under Performance Analysis

For PG&E's over/under performance analysis, data was pooled across the annual systemwide PG&E BIP test events from 2009 to 2011. This data included three different event days. The 2009 test event for PG&E provided data for 164 PG&E customers and data for 187 customers was included from the 2010 test event. Finally, this year's over/under performance analysis was updated with 222 customers that participated in the 2011 PG&E systemwide test event. PG&E's over/under performance analysis and ex ante load impact estimates incorporate data for multiple years because these three test events were consistently called under peaking conditions during the summer, which is reflective of the conditions for which BIP load reductions would most likely be needed.

After pooling the event data, the load shape pattern was determined for each industry and incorporated into the ex ante load impact estimates. Table 5-5 shows the results of the over/under performance analysis by industry for PG&E BIP customers. One industry group (schools) is excluded from the tables because it had less than four 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 97.5% of the expected load reduction given their FSL in the first hour of the event and 99.5% in the last hour of the event.

Performance varies substantially by industry. Customers in the agriculture, mining & construction and wholesale, transport & other utilities segments over perform by more than 10% during event hours. Retail stores under perform substantially, only providing less than 13% of the expected load reduction. The largest BIP industry (manufacturing) under performs slightly, which drives much 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 Systemwide BIP Events from 2009-2011

Industry	N	% Over/Under Performance			
		Hour Before Event	First Hour of Event	Last Hour of Event	Hour After Event
Agriculture, Mining & Construction	86	56.8	111.9	115.7	87.9
Manufacturing	218	45.3	97.9	99.6	72.8
Wholesale, Transport & Other Utilities	130	45.9	113.5	114.1	60.1
Retail Stores	69	-3.0	9.9	12.6	3.1
Offices, Hotels, Finance & Services	37	29.7	91.3	94.8	47.5
Institutional/Government	28	4.2	47.1	47.0	30.2
All Customers	**573**	**43.4**	**97.5**	**99.5**	**68.6**

5.3 Ex Ante Load Impact Estimates

PG&E expects enrollment in its BIP program to increase over the next few years. Enrollment peaks at 265 participants throughout 2015 and 2016 and then decreases gradually to 248 participants at the end of the ex ante forecast period (2022).

BIP load growth as the economy improves is another source of variation in ex ante load impacts throughout the forecast period (2012-2022). As discussed in Section 3.1, PG&E BIP load is assumed to increase by 1.3% per year from 2012 through 2017 and then *decrease* by 0.1% per year from 2018 through 2022. This pattern is consistent with PG&E's internal economic forecast of average load for large business customers. The 1.3% annual increase and 0.1% annual decrease are applied to the estimated reference load, which in turn leads to a proportional change in load impacts.

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 the year 2015. For a 1-in-2 typical event day, the estimated load impact for the average participant is 834.3 kW from 1 PM to 6 PM. This represents a 78.7% impact relative to the average reference load of 1,060.3 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 The average load impact across the event period is 814 kW, which is 2.4% less than in the 1-in-2 weather year. Reasons for the lower 1-in-10 load impacts are discussed below.

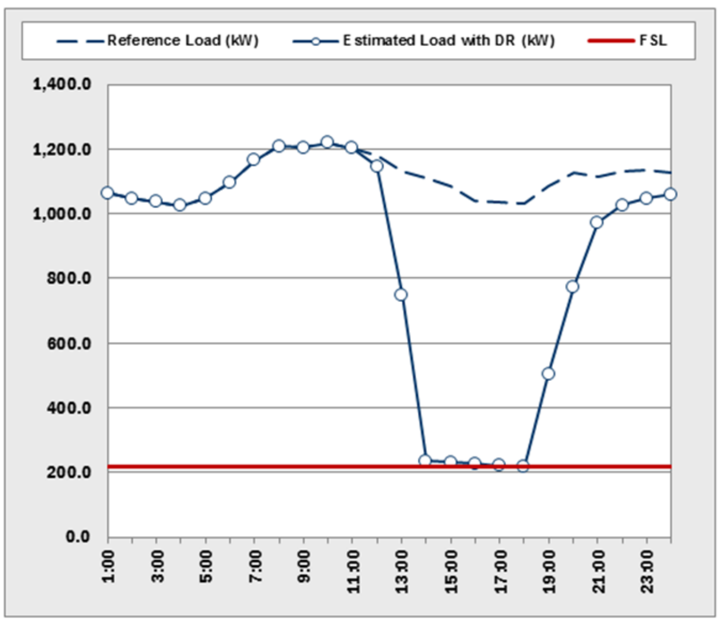
Figure 5-4:
PG&E BIP Average Load Impact (kW) per Customer in 2015
for a Typical Event Day Based on 1-in-2 Year Weather Conditions

TABLE 1: Menu options

Type of Results	Average Enrolled Account
Weather Year	1-in-2
Forecast Year	2015
Day Type	Typical Event Day
Customer Characteristic	All Customers

TABLE 2: Output

Number of Accounts	265
Average FSL (kW)	215.9
Proxy Date	N/A
Average Load Impact (kW) (1-6pm)	834.3
% Load Impact (1-6pm)	78.7%



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	1063.9	1063.8	0.1	71.2	-80.9	-33.1	0.1	33.2	81.0
2:00	1047.7	1047.7	0.0	66.8	-80.8	-33.0	0.0	33.1	80.9
3:00	1036.0	1035.9	0.1	65.3	-80.6	-33.0	0.1	33.1	80.8
4:00	1023.8	1023.7	0.1	64.1	-80.5	-32.9	0.1	33.1	80.7
5:00	1047.6	1047.5	0.1	63.4	-80.8	-33.0	0.1	33.3	81.1
6:00	1097.4	1097.4	0.0	62.8	-81.2	-33.2	0.0	33.3	81.3
7:00	1165.7	1165.8	-0.1	62.9	-81.3	-33.3	-0.1	33.2	81.2
8:00	1209.6	1209.5	0.1	66.4	-81.1	-33.1	0.1	33.4	81.4
9:00	1204.9	1205.3	-0.4	72.0	-81.4	-33.5	-0.4	32.7	80.6
10:00	1218.5	1218.9	-0.4	77.3	-81.1	-33.4	-0.4	32.6	80.3
11:00	1201.6	1201.9	-0.3	82.3	-80.9	-33.3	-0.3	32.8	80.4
12:00	1181.6	1145.6	36.0	86.8	-44.5	3.1	36.0	69.0	116.5
13:00	1129.6	749.2	380.3	90.0	299.8	347.4	380.3	413.3	460.9
14:00	1109.9	235.8	874.2	92.6	793.8	841.3	874.2	907.1	954.6
15:00	1085.7	231.1	854.6	94.5	774.6	821.9	854.6	887.4	934.7
16:00	1039.7	226.9	812.8	95.4	732.8	780.1	812.8	845.6	892.8
17:00	1034.8	220.4	814.4	95.0	734.6	781.8	814.4	847.1	894.2
18:00	1031.3	215.9	815.4	93.6	735.7	782.8	815.4	848.0	895.0
19:00	1087.1	504.9	582.2	91.0	502.4	549.5	582.2	614.8	661.9
20:00	1125.0	774.2	350.8	86.6	270.9	318.1	350.8	383.5	430.7
21:00	1116.2	971.9	144.3	81.5	64.3	111.6	144.3	177.1	224.4
22:00	1131.7	1027.0	104.7	77.6	24.5	71.9	104.7	137.6	185.0
23:00	1136.0	1046.2	89.8	74.9	9.6	57.0	89.8	122.6	170.0
0:00	1126.3	1059.6	66.7	73.0	-13.4	33.9	66.7	99.5	146.8
	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	26,651.7	20,725.9	5,925.8	245.4	2603.9	4547.2	5925.8	7212.3	9219.0

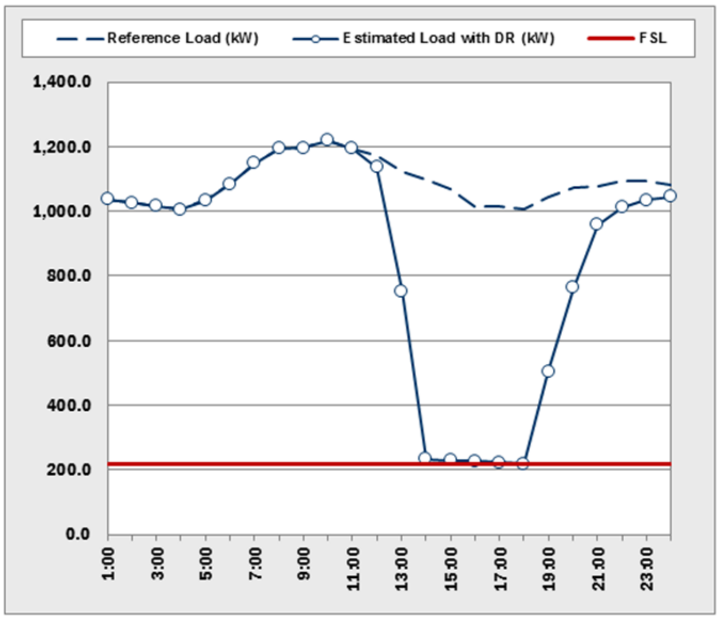
Figure 5-5:
PG&E BIP Average Load Impact (kW) per Customer in 2015
for a Typical Event Day Based on 1-in-10 Year Weather Conditions

TABLE 1: Menu options

Type of Results	Average Enrolled Account
Weather Year	1-in-10
Forecast Year	2015
Day Type	Typical Event Day
Customer Characteristic	All Customers

TABLE 2: Output

Number of Accounts	265
Average FSL (kW)	218.8
Proxy Date	N/A
Average Load Impact (kW) (1-6pm)	814.0
% Load Impact (1-6pm)	78.3%



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	1035.9	1035.9	0.1	75.2	-97.5	-39.9	0.1	40.0	97.6
2:00	1025.8	1025.8	0.0	73.9	-96.1	-39.3	0.0	39.4	96.2
3:00	1015.5	1015.4	0.1	72.7	-95.4	-39.0	0.1	39.1	95.5
4:00	1005.3	1005.2	0.1	71.4	-95.2	-38.9	0.1	39.1	95.4
5:00	1033.4	1033.3	0.1	70.5	-96.4	-39.4	0.1	39.7	96.7
6:00	1083.6	1083.6	0.0	69.6	-98.4	-40.3	0.0	40.3	98.5
7:00	1147.6	1147.6	-0.1	69.4	-98.7	-40.4	-0.1	40.3	98.6
8:00	1194.1	1194.0	0.1	72.0	-97.9	-40.0	0.1	40.2	98.2
9:00	1195.3	1195.7	-0.4	77.2	-96.9	-39.9	-0.4	39.1	96.1
10:00	1218.0	1218.4	-0.4	81.9	-94.8	-39.0	-0.4	38.2	93.9
11:00	1193.2	1193.5	-0.3	86.1	-94.3	-38.7	-0.3	38.2	93.8
12:00	1173.4	1135.4	38.0	90.0	-55.3	-0.2	38.0	76.3	131.4
13:00	1121.4	752.9	368.5	93.4	275.6	330.5	368.5	406.5	461.4
14:00	1096.4	232.7	863.7	95.8	771.4	825.9	863.7	901.5	956.0
15:00	1067.2	229.5	837.7	97.4	746.2	800.3	837.7	875.2	929.2
16:00	1016.4	226.0	790.4	98.4	698.4	752.8	790.4	828.1	882.4
17:00	1014.4	223.1	791.3	98.4	699.0	753.5	791.3	829.1	883.6
18:00	1005.5	218.8	786.8	97.3	694.4	749.0	786.8	824.5	879.1
19:00	1045.7	503.3	542.4	94.8	449.1	504.2	542.4	580.6	635.7
20:00	1074.0	762.8	311.2	90.8	216.9	272.6	311.2	349.8	405.5
21:00	1075.4	958.1	117.3	86.4	23.1	78.8	117.3	155.9	211.5
22:00	1093.0	1012.5	80.5	83.1	-14.0	41.8	80.5	119.1	174.9
23:00	1093.7	1034.2	59.5	80.6	-35.5	20.6	59.5	98.3	154.4
0:00	1080.6	1044.1	36.6	78.9	-57.4	-1.9	36.6	75.0	130.5
	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	26,105.1	20,481.8	5,623.3	326.0	2125.8	4177.9	5623.3	6962.4	9118.7

Table 5-6 shows the aggregate on-peak ex ante load impact estimates for each day type by weather year and selected forecast years. In accordance with the revised resource adequacy hours, the peak period is defined as 1 PM to 6 PM for the typical event day and the April through October monthly peak days and 4 PM to 9 PM for the November through March monthly peak days. Throughout the forecast period (2012-2022), the program is expected to be capable of delivering up to 248.5 MW, which occurs during the September monthly peak under 1-in-2 weather conditions in 2018. The aggregate load impacts drop by 1.2% to 2.4% between 2018 and 2022 because enrollment and the load of BIP customers are forecasted to decrease slightly during that time period. As in the typical event day estimates, the aggregate impacts are lower 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 lead to an increase in system load, but for these BIP customers, extreme temperatures actually lead to slightly lower average load in most months.

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

Weather Year	Day Type	Peak Period	2012	2013	2014	2018	2022
1-in-2	January Peak	4-9 PM	150.5	162.6	173.7	199.2	196.8
	February Peak	4-9 PM	161.4	174.2	185.9	212.6	210.1
	March Peak	4-9 PM	170.8	184.3	196.2	223.2	220.3
	April Peak	1-6 PM	176.6	190.1	201.6	227.3	223.5
	May Peak	1-6 PM	180.1	194.6	206.2	231.9	228.1
	June Peak	1-6 PM	176.7	190.9	201.8	225.6	221.3
	July Peak	1-6 PM	184.4	198.8	209.7	233.1	228.3
	August Peak	1-6 PM	188.2	202.6	213.3	236.2	231.2
	September Peak	1-6 PM	198.8	213.8	224.9	248.5	243.1
	October Peak	1-6 PM	191.8	206.0	216.3	238.0	232.6
	November Peak	4-9 PM	174.0	186.6	196.2	216.7	212.3
	December Peak	4-9 PM	155.5	166.2	174.5	191.4	187.0
1-in-10	January Peak	4-9 PM	145.8	157.4	168.1	192.7	190.4
	February Peak	4-9 PM	167.5	181.0	193.1	221.0	218.4
	March Peak	4-9 PM	165.1	178.1	189.6	215.5	212.6
	April Peak	1-6 PM	176.6	190.1	201.6	227.3	223.5
	May Peak	1-6 PM	172.5	186.2	197.0	220.9	216.8
	June Peak	1-6 PM	179.4	193.8	204.7	228.8	224.5
	July Peak	1-6 PM	180.8	195.0	205.7	228.7	224.0
	August Peak	1-6 PM	184.8	198.8	209.2	231.4	226.3
	September Peak	1-6 PM	195.1	209.9	220.7	243.7	238.4
	October Peak	1-6 PM	195.6	209.9	220.3	242.1	236.5
	November Peak	4-9 PM	165.1	176.9	186.0	205.2	200.9
	December Peak	4-9 PM	143.4	153.2	160.7	176.2	172.0

Table 5-7 provides the 2012 and 2022 average and aggregate load impact estimates by LCA for a typical event day under 1-in-2 weather conditions. The average load impact per customer increases from 801.2 kW in 2012 to 927.2 kW in 2022 because of the forecasted increase in BIP customers' reference load.

Throughout the forecast period, aggregate load impacts are primarily concentrated in PG&E's Other LCA. In 2012, the Other LCA accounts for 63.2% of aggregate impacts and 67.8% in 2022. Although this LCA accounts for around 35% of the total number of customers in each year, the majority of aggregate impacts are concentrated there because customers in the Other LCA provide the largest average load reduction. In 2012 and 2022, Other LCA customers provide an average load reduction of over 1,500 kW, whereas the average load impact for each of the remaining LCAs does not exceed 986 kW. The Greater Bay Area LCA comprises the second largest share of aggregate load impacts, accounting for 14.6% in 2012 and 12.6% in 2022. Although enrollment growth rates are projected to be different across the LCAs, the general composition of the program is expected to remain similar with over 77% of aggregate impacts in the Other and Greater Bay Area LCAs.

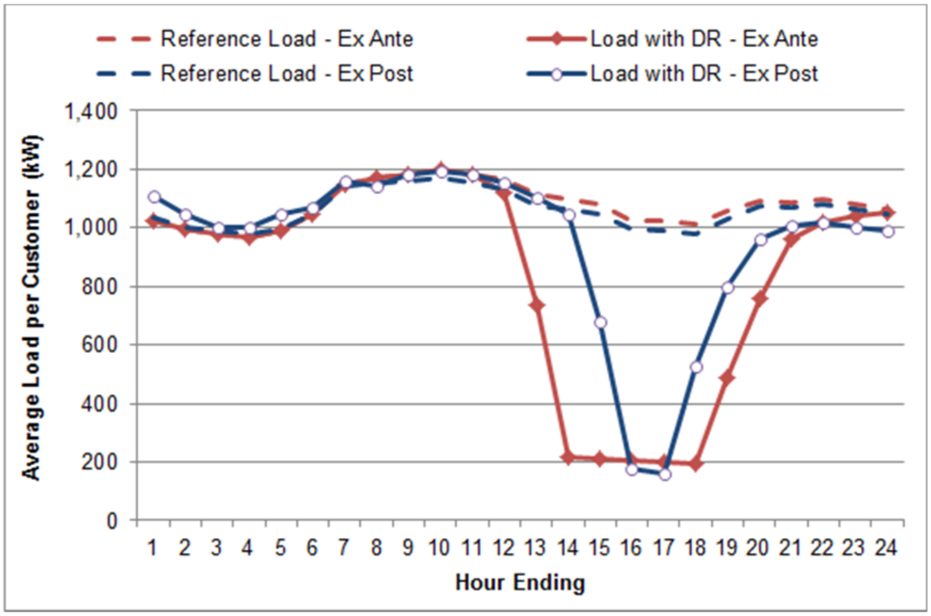
Table 5-7:
2012 and 2022 Average and Aggregate Load Impacts by LCA
Typical Event Day under 1-in-2 Weather Conditions, 1 PM to 6 PM

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
2012	Greater Bay Area	61	681.3	232.8	448.6	27.3	14.6
	Greater Fresno	24	393.0	113.3	279.7	6.6	3.5
	Humboldt	5	477.7	98.5	379.2	1.8	1.0
	Kern	22	617.9	112.4	505.5	11.3	6.0
	Northern Coast	26	668.3	292.3	376.0	9.7	5.2
	Other	76	1,790.2	236.9	1,553.3	118.3	63.2
	Sierra	11	1,051.4	119.5	931.8	10.5	5.6
	Stockton	10	340.5	173.8	166.7	1.7	0.9
	All Customers	**235**	**1,003.0**	**206.5**	**796.5**	**187.2**	**100.0**
2022	Greater Bay Area	59	772.9	277.1	495.8	29.2	12.6
	Greater Fresno	26	439.2	119.2	320.1	8.4	3.6
	Humboldt	3	495.4	104.9	390.5	1.2	0.5
	Kern	24	663.8	117.2	546.6	12.9	5.6
	Northern Coast	22	706.8	294.3	412.5	9.1	3.9
	Other	92	1,939.0	246.0	1,693.0	156.6	67.8
	Sierra	12	1,118.5	133.1	985.4	11.7	5.0
	Stockton	11	370.8	182.2	188.6	2.1	0.9
	All Customers	**249**	**1,149.3**	**222.1**	**927.2**	**231.1**	**100.0**

The ex ante load impact estimates reported in this section closely align with the ex post load impact estimates presented in Section 5.1. The 2011 systemwide BIP test event occurred on September 7, during moderate system load conditions that are comparable to the 1-in-2 September peak in the 2012 ex ante estimates. Figure 5-5 compares these two estimates and shows that the average hourly impact is similar during the event period (3 PM to 5 PM in the ex post estimates and 1 PM to 6 PM in the ex ante estimates). Although the average reference load is nearly identical from 3 PM to 5 PM, the load reduction is slightly higher in the 2011 ex post estimates because event performance is slightly higher. Considering that the over/under performance analysis also factors in the 2009 and 2010 events, the ex ante estimates show slightly lower performance than the 2011 ex post estimates. Outside of the 2012 September peak

1-in-2 ex ante estimates, the load impacts do not align as closely with the ex post because the month is different and in the later years, enrollment and load growth lead to higher impacts.

Figure 5-5:
Comparison of 2011 Ex Post Estimates and 2012 September Peak 1-in-2 Ex Ante Estimates



Another useful comparison for the ex ante load impact estimates is to those of last year's evaluation. In general, the per customer ex ante load impact estimates are lower in this year's evaluation. For example, the 2012 August peak load impact estimate for a 1-in-2 weather year was 202.8 MW in last year's evaluation. With 221 customers projected to be in the program, this was an average load impact of 918.1 kW per customer. In this evaluation, there is a projected 235 customers in August 2012, but the monthly peak load impact estimate for a 1-in-2 weather year is lower at 188.2 MW. This is an average load impact of 800.9 kW per customer, which is roughly 12.8% lower than the estimate in last year's evaluation. This reduction is primarily due to a change in the BIP enrollment mix over the past year. Last year's ex ante analysis was based on a set of customers with an average on-peak load of 1,034.3 kW. In this year's evaluation, the set of customers in the ex ante analysis had an average on-peak load of 948.5 kW. The mix of customers has changed in terms of on-peak load because new enrollees had an average of 632.1 kW, which brought down the overall average. As a result of the reduction in average on-peak load, the average interruptible load (on-peak kW minus FSL) decreased from around 834 kW to 749 kW, which is a 10.2% reduction.

6 SDG&E Load Impact Analysis

This section includes 2011 ex post load impact estimates and 2012-2022 ex ante load impact estimates for SDG&E's BIP program. The discussion of load impacts provided below focuses on the 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 appendices titled, “SDG&E 2011 BIP Ex Post Load Impact Tables" and "SDG&E 2011 BIP Ex Ante Load Impact Tables."

6.1 Ex Post Load Impact Estimates

SDG&E called a BIP event on August 18, 2011 that lasted from 12 PM to 4 PM for BIP option A customers and 3 PM to 6 PM for the single BIP option B customer. Option A customers received 30-minute notice of the event and Option B customers received 3 hours. In total, 21 customers participated in the event.

Figures 6-1 and 6-2 show the average load impact per customer and aggregate impacts in each hour on August 18. The event period common to all participants (3 PM to 4 PM) is highlighted in the figures. As seen in Figure 6-1, the average load drop per customer from 3 PM to 4 PM was 114.1 kW. Figure 6-2 shows that the aggregate load drop from 3 PM to 4 PM was 2.4 MW. This represents roughly a 35% reduction relative to the reference load of 6.9 MW. The 3 PM to 4 PM aggregate load of 4.5 MW was substantially higher than the aggregate FSL of 0.6 MW. BIP customers under performed during this event, providing only 38% of the 6.3 MW reduction that participants needed in order to be in compliance.

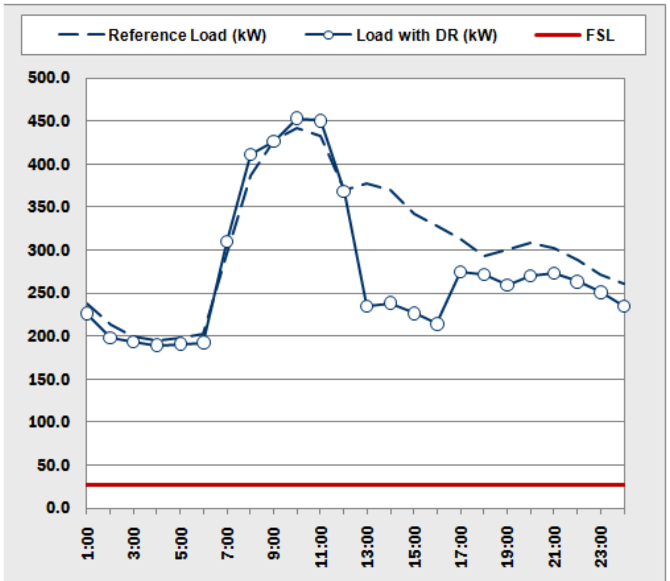
Figure 6-1:
Average Ex Post Load Impact (kW) per Participant for SDG&E BIP Event (August 18, 2011)

TABLE 1: Menu options

Type of Results	Average Enrolled Account
Event	Thursday, August 18, 2011
Customer Characteristic	All Customers

TABLE 2: Output

Number of Accounts	21
Average FSL (kW)	26.8



Note: 3 to 4 PM is the event window that is common to all customers in this category.

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	237.9	226.0	11.9	63.1	-18.1	-0.4	11.9	24.1	41.8
2:00	212.8	198.2	14.6	62.7	-15.4	2.3	14.6	26.8	44.5
3:00	199.4	193.1	6.2	63.1	-23.7	-6.0	6.2	18.5	36.1
4:00	194.8	189.4	5.5	62.5	-24.4	-6.8	5.5	17.7	35.4
5:00	197.9	190.9	7.0	62.9	-22.9	-5.2	7.0	19.2	36.9
6:00	202.2	192.3	9.9	62.9	-19.9	-2.3	9.9	22.2	39.8
7:00	296.0	309.4	-13.4	63.9	-43.5	-25.7	-13.4	-1.0	16.8
8:00	386.7	411.0	-24.3	65.4	-55.2	-37.0	-24.3	-11.7	6.6
9:00	428.5	426.8	1.7	67.5	-29.2	-10.9	1.7	14.4	32.6
10:00	442.1	453.1	-11.0	71.3	-41.9	-23.6	-11.0	1.7	20.0
11:00	432.6	450.3	-17.7	74.0	-48.5	-30.3	-17.7	-5.1	13.1
12:00	370.3	368.2	2.2	74.4	-28.7	-10.5	2.2	14.8	33.0
13:00	376.6	234.9	141.7	75.0	110.9	129.1	141.7	154.3	172.5
14:00	370.0	238.4	131.6	74.7	100.7	119.0	131.6	144.3	162.5
15:00	342.3	226.3	115.9	74.7	85.5	103.5	115.9	128.4	146.4
16:00	328.1	214.0	114.1	72.9	83.5	101.6	114.1	126.6	144.6
17:00	313.0	274.8	38.2	70.0	7.9	25.8	38.2	50.6	68.4
18:00	292.4	271.1	21.2	68.0	-8.9	8.9	21.2	33.6	51.4
19:00	299.9	259.3	40.6	65.9	10.1	28.1	40.5	53.0	71.0
20:00	307.6	269.5	38.1	64.5	7.5	25.6	38.1	50.7	68.8
21:00	302.6	273.0	29.7	64.1	-0.7	17.3	29.7	42.1	60.1
22:00	288.0	263.2	24.8	63.3	-5.5	12.4	24.8	37.1	55.0
23:00	271.4	250.9	20.4	63.3	-9.5	8.2	20.4	32.7	50.4
0:00	261.3	234.4	26.9	64.2	-3.1	14.6	26.9	39.2	56.9
	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	7,354.4	6,618.6	735.8	27.0	587.0	674.9	735.8	796.6	884.5

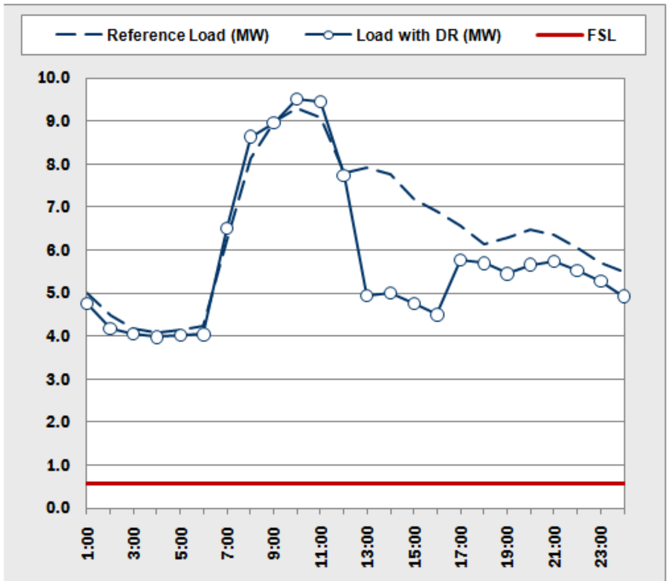
Figure 6-2:
Aggregate Load Impact (MW) for SDG&E BIP Event (August 18, 2011)

TABLE 1: Menu options

Type of Results	Aggregate
Event	Thursday, August 18, 2011
Customer Characteristic	All Customers

TABLE 2: Output

Number of Accounts	21
Aggregate FSL (MW)	0.6



Note: 3 to 4 PM is the event window that is common to all customers in this category.

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	5.0	4.7	0.2	63.1	-0.4	0.0	0.2	0.5	0.9
2:00	4.5	4.2	0.3	62.7	-0.3	0.0	0.3	0.6	0.9
3:00	4.2	4.1	0.1	63.1	-0.5	-0.1	0.1	0.4	0.8
4:00	4.1	4.0	0.1	62.5	-0.5	-0.1	0.1	0.4	0.7
5:00	4.2	4.0	0.1	62.9	-0.5	-0.1	0.1	0.4	0.8
6:00	4.2	4.0	0.2	62.9	-0.4	0.0	0.2	0.5	0.8
7:00	6.2	6.5	-0.3	63.9	-0.9	-0.5	-0.3	0.0	0.4
8:00	8.1	8.6	-0.5	65.4	-1.2	-0.8	-0.5	-0.2	0.1
9:00	9.0	9.0	0.0	67.5	-0.6	-0.2	0.0	0.3	0.7
10:00	9.3	9.5	-0.2	71.3	-0.9	-0.5	-0.2	0.0	0.4
11:00	9.1	9.5	-0.4	74.0	-1.0	-0.6	-0.4	-0.1	0.3
12:00	7.8	7.7	0.0	74.4	-0.6	-0.2	0.0	0.3	0.7
13:00	7.9	4.9	3.0	75.0	2.3	2.7	3.0	3.2	3.6
14:00	7.8	5.0	2.8	74.7	2.1	2.5	2.8	3.0	3.4
15:00	7.2	4.8	2.4	74.7	1.8	2.2	2.4	2.7	3.1
16:00	6.9	4.5	2.4	72.9	1.8	2.1	2.4	2.7	3.0
17:00	6.6	5.8	0.8	70.0	0.2	0.5	0.8	1.1	1.4
18:00	6.1	5.7	0.4	68.0	-0.2	0.2	0.4	0.7	1.1
19:00	6.3	5.4	0.9	65.9	0.2	0.6	0.9	1.1	1.5
20:00	6.5	5.7	0.8	64.5	0.2	0.5	0.8	1.1	1.4
21:00	6.4	5.7	0.6	64.1	0.0	0.4	0.6	0.9	1.3
22:00	6.0	5.5	0.5	63.3	-0.1	0.3	0.5	0.8	1.2
23:00	5.7	5.3	0.4	63.3	-0.2	0.2	0.4	0.7	1.1
0:00	5.5	4.9	0.6	64.2	-0.1	0.3	0.6	0.8	1.2
	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	154.4	139.0	15.5	27.0	12.3	14.2	15.5	16.7	18.6

Table 6-1 shows the average load impact per customer for program option A, for all customers and for the three industry categories with more than three event participants.[12] Table 6-2 shows the aggregate impacts. For each customer category, ex post results are reported for the event window that is common to all customers in that category. Manufacturing customers under performed, providing only 9.9% of the expected load reduction. It does not seem like the five retail stores responded to the event because the event impact is slightly negative and their aggregate load on that day does not show any change in the usual load shape pattern. Customers in the offices, hotels, finance & services segment had the highest performance of the categories listed below (59%). From 12 PM to 4 PM, program option A provided an average load reduction of 130 kW per participant, 39% performance and an aggregate load impact of 2.6 MW.

Table 6-1:
Average Customer Load Impact for August 18, 2011 SDG&E Event

Customer Category	Common Event Window	Number of Customers	Ref. Load (kW)	Load with DR (kW)	Load Reduction (kW)	Average FSL (kW)	Performance (%)
Manufacturing	3 to 4 PM	7	354.0	320.0	34.0	10.1	9.9
Retail Stores	12 to 4 PM	5	154.6	156.5	-1.9	11.2	-1.3
Offices, Hotels, Finance & Services	12 to 4 PM	6	445.1	183.7	261.4	1.8	59.0
Program Option A	12 to 4 PM	20	358.7	228.7	130.0	25.7	39.0
All Customers	3 to 4 PM	21	328.1	214.0	114.1	26.8	37.9

Table 6-2:
Aggregate Load Impact for August 18, 2011 SDG&E Event

Customer Category	Common Event Window	Number of Customers	Ref. Load (MW)	Load with DR (MW)	Load Reduction (MW)	% Load Reduction	FSL (MW)	Performance (%)
Manufacturing	3 to 4 PM	7	2.48	2.24	0.24	9.6	0.07	9.9
Retail Stores	12 to 4 PM	5	0.77	0.78	-0.01	-1.2	0.06	-1.3
Offices, Hotels, Finance & Services	12 to 4 PM	6	2.67	1.10	1.57	58.7	0.01	59.0
Program Option A	12 to 4 PM	20	7.17	4.57	2.60	36.2	0.51	39.0
All Customers	3 to 4 PM	21	6.89	4.49	2.40	34.8	0.56	37.9

6.2 Multiple Program Participation

There are six SDG&E customers that are dually enrolled in BIP and Critical Peak Pricing (CPP), which is the only other DR program in which SDG&E BIP customers can participate. Table 6-3 provides the 2010 and 2011 CPP and BIP event load impacts per customer for these dually enrolled participants. Table 6-4 provides the aggregate load impacts. Dually enrolled customers participated in four CPP events in 2010,

[12] Results for program option B, wholesale, transport & other utilities and agriculture, mining & construction are omitted because these customer categories had three or fewer event participants.

two CPP events in 2011 and one BIP event in 2011.[13] The average and aggregate reference loads and load reductions decrease from 2010 to 2011 because one large dually enrolled customer dropped out of BIP in 2010 and was replaced by a smaller customer in 2011. Although the customer mix changed from year to year, dually enrolled customers consistently provided a large percent load reduction for all CPP event days and the 2011 BIP event day. In the two CPP events in 2011, dually enrolled customers provided 69.9% and 58.6% load reductions. These percent load reductions are substantially higher than the 6.3% and 5.2% load reductions for the average CPP customer overall.

The 2011 BIP percent load impact is similar to the CPP percent impact for dually enrolled customers. For the 2011 BIP event day, dually enrolled customers provided a 61.5% load impact, which is in between the 58.6% and 69.0% percent load impacts for the two CPP event days. This result suggests that these dually enrolled SDG&E CPP/BIP customers are unlikely to provide an incremental load impact if both programs were called on the same day.[14] Portfolio forecasting methods assume all events are called on the same day and are required for many resource planning proceedings. Without an incremental benefit when both events are called on the same day, there will be no increase in the portfolio forecast due to dual participation. Nonetheless, this finding does not imply that dual enrollment has no benefits. If these dually enrolled customers were forced to choose between BIP and CPP, they might choose BIP because it has large incentives and BIP events are called less frequently (albeit with a much shorter notification lead time). Considering that these customers provide substantially higher percent load reductions on CPP event days than the average participant, this would lower the amount of load reduction available for the more frequent CPP events.

Table 6-3:
Average Customer Load Impact for Dually Enrolled CPP/BIP Participants for CPP and BIP Events in 2010 and 2011

Event Date and Type	Event Window	Number of Customers	Average FSL (kW)	Ref. Load (kW)	Load with DR (kW)	Load Reduction (kW)	% Load Reduction
August 25, 2010 CPP Event	11 AM to 6 PM	6	2.3	806.6	147.6	659.0	81.7
August 26, 2010 CPP Event	11 AM to 6 PM	6	2.3	801.9	140.5	661.4	82.5
September 27, 2010 CPP Event	11 AM to 6 PM	6	2.3	836.4	185.8	650.6	77.8
September 28, 2010 CPP Event	11 AM to 6 PM	6	2.3	821.1	168.0	653.1	79.5
August 18, 2011 BIP Event	12 to 4 PM	6	10.7	435.0	167.3	267.7	61.5
August 27, 2011 CPP Event	11 AM to 6 PM	6	10.7	378.9	114.1	264.8	69.9
September 7, 2011 CPP Event	11 AM to 6 PM	6	10.7	442.0	183.1	258.9	58.6

[13] On September 27, 2010, SDG&E called events for both BIP and CPP. Dually enrolled CPP/BIP participants were instructed to only respond to the CPP event and did not participate in the BIP event. Considering that September 27 was the only BIP event day in 2010, dually enrolled CPP/BIP participants did not participate in a BIP event in 2010.

[14] This comparison is approximate because these event days had different weather patterns and CPP and BIP have different event hours.

Table 6-4:
Aggregate Load Impact for Dually Enrolled CPP/BIP Participants for CPP and BIP Events in 2010 and 2011

Event Date and Type	Event Window	Number of Customers	FSL (MW)	Ref. Load (MW)	Load with DR (MW)	Load Reduction (MW)	% Load Reduction
August 25, 2010 CPP Event	11 AM to 6 PM	6	0.01	4.84	0.89	3.95	81.7
August 26, 2010 CPP Event	11 AM to 6 PM	6	0.01	4.81	0.84	3.97	82.5
September 27, 2010 CPP Event	11 AM to 6 PM	6	0.01	5.02	1.11	3.90	77.8
September 28, 2010 CPP Event	11 AM to 6 PM	6	0.01	4.93	1.01	3.92	79.5
August 18, 2011 BIP Event	12 to 4 PM	6	0.06	2.61	1.00	1.61	61.5
August 27, 2011 CPP Event	11 AM to 6 PM	6	0.06	2.27	0.68	1.59	69.9
September 7, 2011 CPP Event	11 AM to 6 PM	6	0.06	2.65	1.10	1.55	58.6

Dually enrolled CPP/BIP participants also provide substantially higher percent load reductions than the average BIP customer. Table 6-5 provides the 2010 and 2011 BIP event load impacts per customer for BIP-only participants. Table 6-6 provides the aggregate load impacts. BIP customers that are not dually enrolled in CPP provided an 18.7% load reduction for the 2011 BIP event, which is less than one-third of the percent load impact provided by CPP/BIP participants. Without dually enrolled participants, the aggregate impact for the 2011 BIP event would have been 0.8 MW. CPP/BIP customers accounted for 6 out of 21 participants in the 2011 BIP event, but 67% of the aggregate load impact. In short, dually enrolled CPP/BIP participants provide relatively large percent load impacts that are valuable to both programs.

Table 6-5:
Average Customer Load Impact for BIP-only Participants for BIP Events in 2010 and 2011

Event Date and Type	Common Event Window	Number of Customers	Average FSL (kW)	Ref. Load (kW)	Load with DR (kW)	Load Reduction (kW)	% Load Reduction
September 27, 2010 BIP Event	3 to 6 PM	13	6.5	192.5	160.2	32.2	16.7
August 18, 2011 BIP Event	3 to 4 PM	15	33.3	285.2	231.9	53.3	18.7

Table 6-6:
Aggregate Load Impact for BIP-only Participants for BIP Events in 2010 and 2011

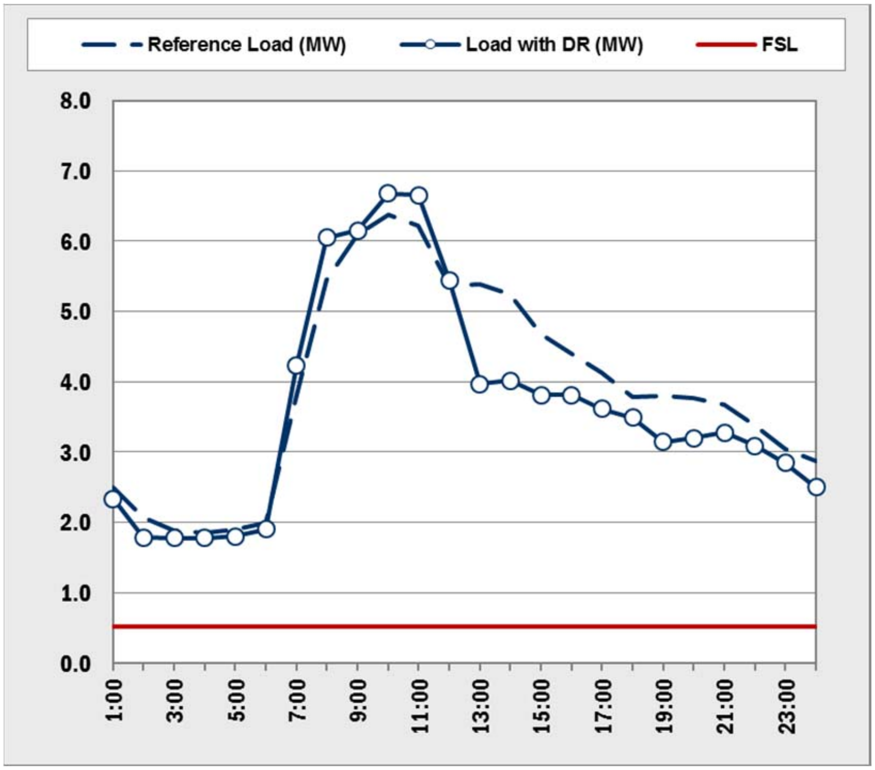
Event Date and Type	Common Event Window	Number of Customers	FSL (MW)	Ref. Load (MW)	Load with DR (MW)	Load Reduction (MW)	% Load Reduction
September 27, 2010 BIP Event	3 to 6 PM	13	0.08	2.50	2.08	0.42	16.7
August 18, 2011 BIP Event	3 to 4 PM	15	0.50	4.28	3.48	0.80	18.7

6.3 Over/Under Performance Analysis

For SDG&E's over/under performance analysis, data for the 2011 BIP event was used. Data for multiple years was not pooled together, as in PG&E's over/under performance analysis, because SDG&E's program has changed substantially in recent months. In fact, several customers that historically provided relatively large load impacts have left the program since the 2011 event. Therefore, SDG&E's over/under performance analysis is based on data for the 2011 BIP event, specifically for the 17 customers that are still enrolled in the program.

Figure 6-3 shows the aggregate load impacts for the 2011 SDG&E BIP event for customers that are still enrolled in the program. Considering that the remaining BIP customers were all in Option A, curtailment was required from 12 PM to 4 PM. Among the 17 customers that are still enrolled in the program, the aggregate hourly impact during the event period was 1.02 MW and performance was 23.2%. Considering that these customers are representative of the current program, the 23.2% performance value is what was used for the ex ante analysis.

Figure 6-3:
Aggregate Load Impact (MW) for 2011 SDG&E BIP Event for Customers that are Currently Enrolled in the Program (As of May 2012)



6.4 Ex Ante Load Impact Estimates

SDG&E plans to increase enrollment in its BIP program over the next few years. In May 2013, SDG&E BIP enrollment is expected to equal 51 participants and 105 in December 2014. Afterwards, enrollment is assumed to remain constant until the end of the ex ante forecast period (2022).

Figures 6-4 and 6-5 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 the year 2015. Impacts are reported for 2015 because it is the year in which enrollment growth reaches a steady state through 2022. For a 1-in-2 typical event day, the estimated load impact for the average participant is 54.4 kW from 1 PM to 6 PM. This represents a 20.6% impact relative to the average reference load of 264.6 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 because BIP customer usage is not sensitive to temperature. The average load impact across the event period is 54.3 kW, which is less than 1% lower than in the 1-in-2 weather year.

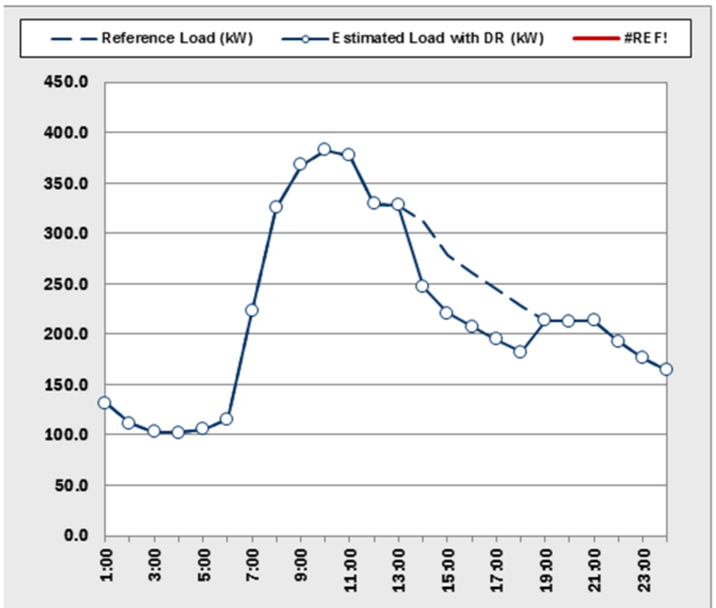
Figure 6-4:
SDG&E BIP Average Load Impact (kW) per Customer in 2015
for a Typical Event Day Based on 1-in-2 Year Weather Conditions

TABLE 1: Menu options

Type of Results	Average Enrolled Account
Weather Year	1-in-2
Forecast Year	2015-2022
Day Type	Typical Event Day
Customer Characteristic	All Customers

TABLE 2: Output

Number of Accounts	105
Average FSL (kW)	30.1
Proxy Date	N/A
Average Load Impact (kW) (1-6pm)	54.4
% Load Impact (1-6pm)	20.6%



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	131.3	131.3	0.0	70.3	-35.5	-14.5	0.0	14.5	35.5
2:00	111.7	111.7	0.0	69.7	-35.4	-14.5	0.0	14.5	35.4
3:00	103.0	103.0	0.0	69.1	-35.4	-14.5	0.0	14.5	35.4
4:00	102.3	102.3	0.0	68.6	-35.4	-14.5	0.0	14.5	35.4
5:00	105.5	105.5	0.0	68.7	-35.4	-14.5	0.0	14.5	35.4
6:00	115.3	115.3	0.0	68.8	-35.4	-14.5	0.0	14.5	35.4
7:00	222.8	222.8	0.0	69.2	-35.8	-14.7	0.0	14.7	35.8
8:00	325.1	325.1	0.0	71.6	-37.3	-15.3	0.0	15.3	37.3
9:00	368.0	368.0	0.0	75.6	-37.4	-15.3	0.0	15.3	37.4
10:00	382.7	382.7	0.0	79.3	-37.3	-15.2	0.0	15.2	37.3
11:00	377.2	377.2	0.0	82.9	-36.9	-15.1	0.0	15.1	36.9
12:00	329.0	329.0	0.0	83.3	-36.9	-15.1	0.0	15.1	36.9
13:00	328.0	328.0	0.0	83.1	-36.7	-15.0	0.0	15.0	36.7
14:00	311.9	246.6	65.4	82.5	28.5	50.3	65.4	80.4	102.2
15:00	277.9	220.4	57.5	82.3	20.7	42.4	57.5	72.5	94.2
16:00	261.0	207.4	53.5	81.8	16.5	38.4	53.5	68.7	90.6
17:00	244.7	195.0	49.8	80.8	13.5	34.9	49.8	64.6	86.1
18:00	227.6	181.8	45.8	78.7	9.7	31.0	45.8	60.6	82.0
19:00	213.6	213.6	0.0	76.4	-36.4	-14.9	0.0	14.9	36.4
20:00	213.0	213.0	0.0	74.1	-36.7	-15.0	0.0	15.0	36.7
21:00	213.1	213.1	0.0	72.6	-36.4	-14.9	0.0	14.9	36.4
22:00	192.9	192.9	0.0	72.1	-36.1	-14.8	0.0	14.8	36.1
23:00	176.2	176.2	0.0	71.6	-35.5	-14.5	0.0	14.5	35.5
0:00	163.8	163.8	0.0	70.5	-35.5	-14.5	0.0	14.5	35.5
	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	5,497.7	5,225.8	271.9	129.7	94.2	199.2	271.9	344.7	449.7

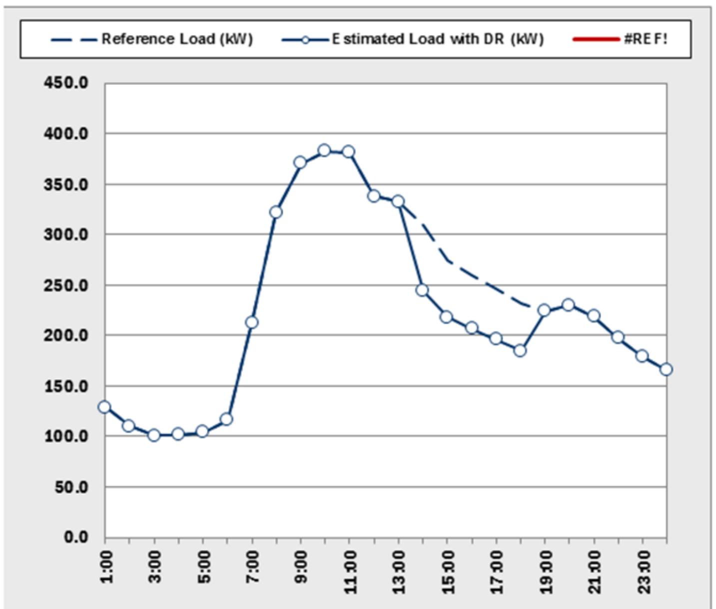
Figure 6-5:
SDG&E BIP Average Load Impact (kW) per Customer in 2015
for a Typical Event Day Based on 1-in-10 Year Weather Conditions

TABLE 1: Menu options

Type of Results	Average Enrolled Account
Weather Year	1-in-10
Forecast Year	2015-2022
Day Type	Typical Event Day
Customer Characteristic	All Customers

TABLE 2: Output

Number of Accounts	105
Average FSL (kW)	30.1
Proxy Date	N/A
Average Load Impact (kW) (1-6pm)	54.3
% Load Impact (1-6pm)	20.5%



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	128.9	128.9	0.0	73.1	-35.6	-14.6	0.0	14.6	35.6
2:00	110.4	110.4	0.0	72.3	-35.5	-14.5	0.0	14.5	35.5
3:00	100.9	100.9	0.0	72.0	-35.4	-14.5	0.0	14.5	35.4
4:00	101.3	101.3	0.0	71.2	-35.4	-14.5	0.0	14.5	35.4
5:00	104.4	104.4	0.0	71.1	-35.5	-14.5	0.0	14.5	35.5
6:00	116.0	116.0	0.0	70.9	-35.4	-14.5	0.0	14.5	35.4
7:00	212.5	212.5	0.0	71.6	-36.1	-14.8	0.0	14.8	36.1
8:00	322.1	322.1	0.0	74.7	-37.8	-15.5	0.0	15.5	37.8
9:00	370.2	370.2	0.0	78.1	-37.6	-15.4	0.0	15.4	37.6
10:00	382.2	382.2	0.0	81.5	-37.4	-15.3	0.0	15.3	37.4
11:00	381.2	381.2	0.0	83.9	-37.1	-15.2	0.0	15.2	37.1
12:00	337.9	337.9	0.0	85.3	-37.5	-15.4	0.0	15.4	37.5
13:00	332.4	332.4	0.0	85.0	-37.5	-15.3	0.0	15.3	37.5
14:00	308.7	244.1	64.6	85.2	26.6	49.1	64.6	80.2	102.6
15:00	274.6	217.9	56.7	85.7	18.7	41.1	56.7	72.3	94.7
16:00	259.7	206.4	53.2	85.0	14.7	37.5	53.2	69.0	91.7
17:00	246.0	196.0	50.1	83.2	12.8	34.8	50.1	65.4	87.4
18:00	231.6	184.9	46.7	81.5	9.8	31.6	46.7	61.8	83.6
19:00	223.8	223.8	0.0	78.9	-37.1	-15.2	0.0	15.2	37.1
20:00	229.8	229.8	0.0	75.9	-37.4	-15.3	0.0	15.3	37.4
21:00	219.0	219.0	0.0	74.9	-36.8	-15.1	0.0	15.1	36.8
22:00	197.5	197.5	0.0	74.2	-36.3	-14.9	0.0	14.9	36.3
23:00	178.7	178.7	0.0	73.5	-35.5	-14.5	0.0	14.5	35.5
0:00	165.2	165.2	0.0	72.8	-35.5	-14.5	0.0	14.5	35.5

	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	5,535.1	5,263.7	271.4	181.4	91.4	197.7	271.4	345.0	451.3

Table 6-7 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 PM to 6 PM for the typical event day and the April through October monthly peak days and 4 PM to 9 PM for the November through March monthly peak days. As a result of the change in peak period timing, aggregate impacts fluctuate throughout the year. During the 2015 to 2022 time period, 1-in-2 and 1-in-10 aggregate load impacts vary from 3.36 MW to 5.6 MW in November through March and 5.63 MW to 6.94 MW in April through October. For SDG&E BIP customers, usage is higher from 1 PM to 6 PM than it is from 4 PM to 9 PM, as shown in Figures 6-4 and 6-5. This load shape results in a fluctuation in aggregate load impacts as the peak period timing changes throughout the year.

Once enrollment reaches a steady state in the 2015 to 2021 time period, the program is expected to be capable of delivering up to 6.94 MW, which occurs during the April monthly peak under 1-in-10 weather conditions. As a result of new enrollment, aggregate load impacts for the 1-in-2 typical event day grow from 1.39 MW in 2012 to nearly 5.71 MW during 2015 to 2022.

Table 6-7:
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	2012	2013	2014	2015-2022
1-in-2	Typical Event Day	1-6 PM	1.39	3.24	5.09	5.71
	January Peak	4-9 PM	0.54	1.27	2.36	3.36
	February Peak	4-9 PM	0.71	1.77	3.18	4.37
	March Peak	4-9 PM	0.72	1.93	3.38	4.47
	April Peak	1-6 PM	1.10	3.11	5.30	6.77
	May Peak	1-6 PM	1.00	3.01	5.02	6.20
	June Peak	1-6 PM	1.14	3.09	5.04	6.02
	July Peak	1-6 PM	1.31	3.28	5.25	6.09
	August Peak	1-6 PM	1.37	3.19	5.01	5.63
	September Peak	1-6 PM	1.73	3.80	5.87	6.40
	October Peak	1-6 PM	1.98	4.15	6.31	6.68
	November Peak	4-9 PM	1.81	3.63	5.44	5.60
	December Peak	4-9 PM	1.46	2.81	4.16	4.17
1-in-10	Typical Event Day	1-6 PM	1.38	3.23	5.07	5.70
	January Peak	4-9 PM	0.64	1.50	2.79	3.98
	February Peak	4-9 PM	0.81	2.04	3.66	5.03
	March Peak	4-9 PM	0.88	2.35	4.11	5.44
	April Peak	1-6 PM	1.12	3.19	5.43	6.94
	May Peak	1-6 PM	1.06	3.17	5.28	6.52
	June Peak	1-6 PM	1.14	3.09	5.04	6.02
	July Peak	1-6 PM	1.31	3.27	5.24	6.07
	August Peak	1-6 PM	1.38	3.22	5.06	5.68
	September Peak	1-6 PM	1.61	3.54	5.48	5.97
	October Peak	1-6 PM	1.94	4.06	6.17	6.53
	November Peak	4-9 PM	1.60	3.21	4.81	4.95
	December Peak	4-9 PM	1.31	2.52	3.73	3.74

7 Recommendations for All Utilities

The events in 2011 improved the quality of the over/under performance analysis, which in turn, improved the quality of the ex ante estimates. We recommend that all utilities continue to call at least one event each year.

When calling a test event, all utilities need to consider the event conditions that they are attempting to simulate. The 2011 events for SCE, PG&E and SDG&E simulated different event conditions. PG&E and SDG&E did not provide advance notification of the event[15], whereas SCE provided 24-hour advance notification. Although the notification lead time for BIP is much shorter than 24 hours, the SCE test events simulated a situation where customers expect a BIP event given generation supply shortages during a long heat wave. The PG&E and SDG&E events simulated a situation where an important transmission or distribution line falls and customers do not expect a BIP event.

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, as SCE did in 2011. If a BIP test event is meant to simulate a transmission or distribution outage, no advanced notice should be given.

[15] However, some of the PG&E customers might have been reminded about their event preparedness ahead of time by their account representatives who perceived a high likelihood of a test event, given the weather conditions and the timing of prior test events.

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 utility 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 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	1,002.6	1,047.9	45.3	4.52%	1,026.9	1,040.2	13.3	1.30%	228.5	227.8	-0.7	-0.29%
2	1,004.5	1,038.7	34.2	3.41%	1,007.9	1,018.4	10.4	1.03%	208.4	206.3	-2.1	-1.00%
3	985.2	1,023.8	38.6	3.92%	992.2	1,003.7	11.5	1.16%	198.7	194.9	-3.7	-1.88%
4	994.5	1,028.7	34.1	3.43%	973.0	996.2	23.2	2.38%	197.2	192.7	-4.6	-2.31%
5	1,037.7	1,067.7	30.0	2.89%	990.7	1,014.6	23.8	2.41%	204.0	198.0	-6.0	-2.92%
6	1,085.8	1,107.3	21.5	1.98%	1,039.9	1,054.0	14.1	1.36%	214.9	206.5	-8.4	-3.93%
7	1,128.7	1,145.2	16.5	1.46%	1,116.4	1,122.7	6.2	0.56%	307.9	293.8	-14.1	-4.57%
8	1,141.8	1,156.6	14.8	1.29%	1,141.1	1,152.9	11.8	1.04%	408.0	386.3	-21.8	-5.34%
9	1,157.2	1,152.7	-4.5	-0.39%	1,128.3	1,150.2	21.9	1.94%	453.2	435.7	-17.4	-3.85%
10	1,169.0	1,163.4	-5.7	-0.49%	1,139.6	1,154.1	14.6	1.28%	466.1	452.1	-14.1	-3.02%
11	1,177.5	1,176.5	-1.0	-0.08%	1,129.5	1,137.7	8.2	0.73%	457.9	446.9	-11.0	-2.40%
12	1,176.2	1,170.8	-5.5	-0.47%	1,110.2	1,116.2	6.1	0.55%	399.5	402.4	2.9	0.73%
13	1,162.4	1,154.5	-7.9	-0.68%	1,053.2	1,066.9	13.7	1.30%	401.4	403.6	2.2	0.55%
14	1,150.7	1,142.6	-8.1	-0.70%	1,036.0	1,053.2	17.2	1.66%	382.5	392.0	9.5	2.47%
15	1,121.0	1,121.7	0.7	0.07%	1,018.0	1,030.3	12.3	1.21%	357.3	361.7	4.5	1.25%
16	1,098.1	1,102.6	4.6	0.42%	968.7	986.8	18.1	1.87%	341.8	349.9	8.1	2.38%
17	1,081.0	1,086.9	5.9	0.55%	971.6	984.5	12.9	1.33%	318.8	327.5	8.7	2.73%
18	1,063.2	1,066.6	3.4	0.32%	966.4	974.0	7.6	0.79%	295.1	301.4	6.3	2.13%
19	1,064.7	1,072.0	7.2	0.68%	1,015.5	1,025.4	9.9	0.98%	304.7	307.8	3.1	1.03%
20	1,081.0	1,081.1	0.1	0.01%	1,049.4	1,061.9	12.5	1.19%	326.1	321.6	-4.5	-1.37%
21	1,088.8	1,088.9	0.1	0.01%	1,048.5	1,056.7	8.2	0.78%	317.6	310.6	-7.0	-2.21%
22	1,073.1	1,072.0	-1.1	-0.10%	1,066.8	1,067.4	0.6	0.06%	290.4	287.7	-2.7	-0.93%
23	1,081.6	1,089.7	8.1	0.75%	1,068.9	1,068.6	-0.3	-0.03%	279.1	272.0	-7.1	-2.53%
24	1,094.0	1,101.7	7.7	0.70%	1,049.5	1,059.5	10.0	0.96%	269.4	259.3	-10.1	-3.74%
Avg. (1-6 PM)	**1,102.8**	**1,104.1**	**1.3**	**0.12%**	**992.2**	**1,005.8**	**13.6**	**1.37%**	**339.1**	**346.5**	**7.4**	**2.19%**