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CALMAC Study ID: SCE02956

2010 Load Impact Evaluation of California's Statewide Base Interruptible Program

April 1, 2011

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1 Executive Summary

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 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 California Independent System Operator (CAISO) can dispatch for system emergencies and the utilities can dispatch for 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 January 2010, enrollment in BIP equaled 626 accounts for SCE, 189 accounts for PG&E and 21 accounts for SDG&E.

One of the most important issues facing the statewide BIP program is the cap on emergency DR programs that was recently adopted by the utilities, CPUC and CAISO.[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 (2011-2021). PG&E and SDG&E have more room for growth in emergency DR within their cap allocations. PG&E plans to increase enrollment in its BIP program over the next few years, reaching 267 participants by 2021. SDG&E BIP enrollment is expected to equal 55 in May 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 the 2010 events for PG&E and SDG&E. Ex ante estimates are provided for the years 2011 through 2021.

1.1 Ex Post Load Impact Estimates

This report provides ex post load impact estimates for events called in 2010. PG&E and SDG&E each called a BIP test event in 2010. PG&E implemented a test event on August 24th for two hours. For SDG&E, a test event was implemented for four hours for BIP option A customers and three hours for BIP option B customers on September 27th. SCE has not called a BIP event since September 23, 2009. Ex post analysis for events prior to 2010 was conducted in conjunction with previous evaluations.

The August 24, 2010 event for PG&E lasted two hours, from 3 PM to 5 PM. It was a test event that included all of the 189 customers that were enrolled in BIP at that time. The average load drop per customer over the two-hour event period was 787.9 kW. In aggregate, the load reduction during the event period was 148.9 MW. This represents roughly a 76% reduction relative to the reference load of 196.6 MW. The event-period load of 47.7 MW is slightly higher than the aggregate FSL of 39.2 MW. BIP customers slightly under performed, reducing load by roughly 5% less than what was required to meet their FSL commitments.

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

On September 27, 2010, SDG&E called its first BIP event since 2007. It was a test event that lasted from 2 PM to 6 PM for BIP option A customers and 3 PM to 6 PM for BIP option B customers. BIP customers dually-enrolled in CPP were not required to respond to the BIP event because there was a CPP event on the same day. In total, 13 SDG&E customers responded to the BIP event. For all but one customer, this day was their first BIP event because they enrolled in the program after 2007. The average load drop per customer from 3 PM to 6 PM was 32.2 kW. In aggregate, the load impact was 0.42 MW, which was roughly a 17% reduction relative to the reference load of 2.5 MW. The three-hour event period load of 2.08 MW was substantially higher than the aggregate FSL of 0.08 MW. SDG&E BIP customers significantly under performed during this event, providing only 17.4% of the 2.42 MW reduction that BIP customers 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 continued growth. Figure 1-1 shows the amount of DR available from 2011 through 2021 by utility. For the typical event day in a 1-in-2 weather year, the program is projected to deliver 725 MW in 2011. By 2014, the aggregate load impact is expected to grow by 12% to 815 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 2015 through 2021, the aggregate impact remains around 827 MW in each year. Toward the end of the forecast period, the aggregate load reduction decreases slightly because PG&E anticipates a small decline in usage among its large business customers in those years. In each forecast year, around 68% to 74% of the aggregate load reduction comes from SCE, 25% to 30% from PG&E and the remaining 1% to 2% 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:
2011-2021 Aggregate Load Impacts by Utility and Forecast Year
Typical Event Day in a 1-in-2 Weather Year

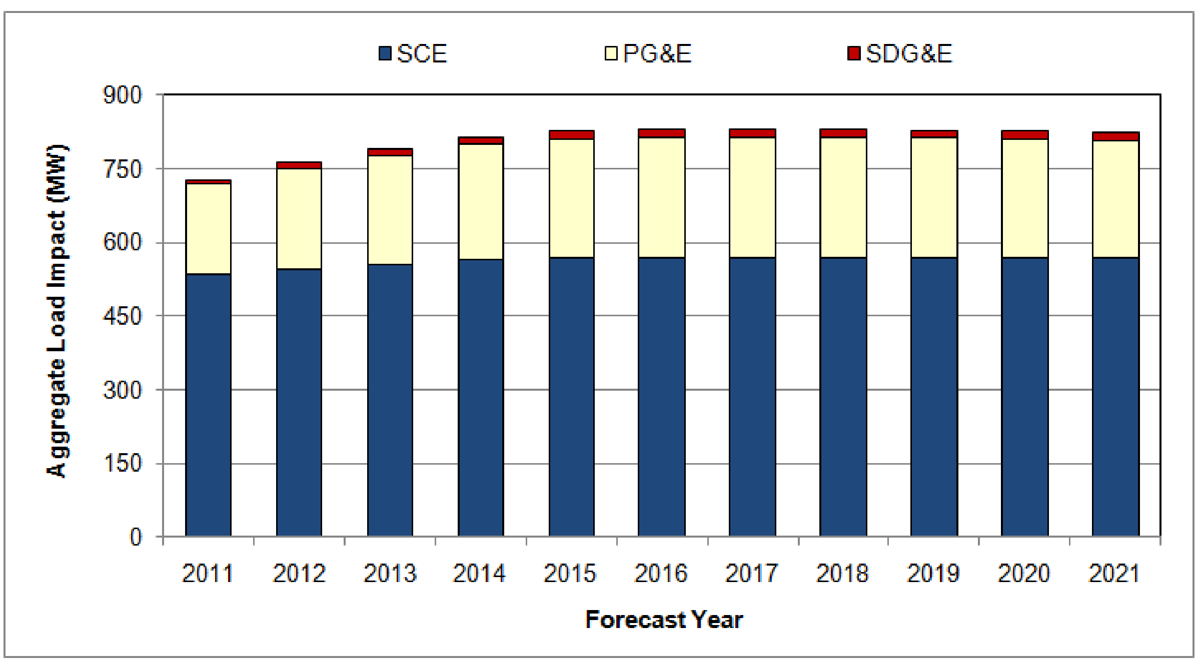
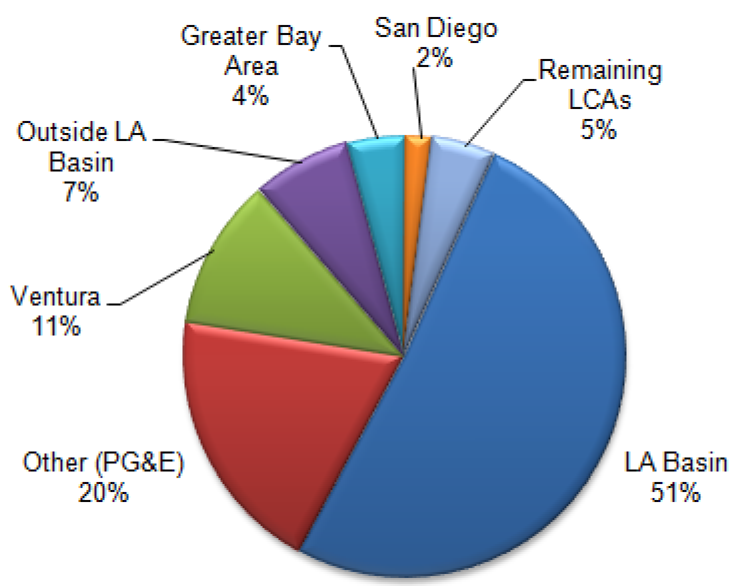


Figure 1-2 shows the distribution of statewide aggregate load impacts in 2015 by local capacity area (LCA). LCAs are CAISO-designated planning regions in which utilities must meet local resource adequacy requirements. For the August monthly peak day in a 1-in-2 weather year in 2015, the statewide aggregate load impact is 818 MW. The LA Basin LCA in SCE's service territory comprises 51% of the statewide aggregate load impact. PG&E's Other LCA is the only area outside of SCE's territory that provides more than 4% of the statewide aggregate load impact.

Figure 1-2:
Distribution of 2015 Statewide Aggregate Load Impacts by Local Capacity Area
August Monthly Peak Day in a 1-in-2 Weather Year
Total Statewide Aggregate Impact = 818 MW



2 Introduction and Program Summary

This report documents the 2010 ex post load impact estimates for California's statewide Base Interruptible Program (BIP) and provides ex ante load impact estimates from 2011 through 2021. 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 California Independent System Operator (CAISO) can dispatch for system emergencies and the utilities can dispatch for 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, BIP could only be triggered by the CAISO under Stage 2 emergency conditions (e.g., when operating reserves are less than 5%) or on a test-event basis. At the request of the CAISO, the California Public Utilities Commission (CPUC) ruled[2] that the three utilities must modify their tariffs. The revised tariffs allow the CAISO to call BIP after it 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 2010. PG&E and SDG&E each called a BIP test event in 2010. PG&E implemented a test event on August 24th for two hours. For SDG&E, a test event was implemented for four hours for BIP option A customers and three hours for BIP option B customers on September 27th. SCE has not called a BIP event since September 23, 2009. Ex post analysis for events prior to 2010 was conducted in conjunction with previous evaluations.

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 2011 to 2021. The load impact estimates presented here are intended to conform to the requirements of the CPUC Demand Response Load Impact Protocols.[3]

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 recently adopted by the utilities, CPUC and CAISO.[4] 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. The cap will be allocated to the utilities *in proportion* to the following:

- PG&E: 400 MW;

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

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

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

- 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. Recommendations for managing BIP enrollment are provided in Section 7.

2.2 Overview of SCE's BIP Program

SCE's BIP program is designed for customers and aggregators with demands of 200 kW and above. The program includes two notification options: option A with a 15-minute notification lead time and option B with a 30-minute notification requirement. Interruption events for an individual BIP customer or aggregated group are limited to a single 4-hour event per day, and no more than 120 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 January 2011, SCE had 626 service accounts enrolled in the BIP program, of which 89% were in the 30-minute notification option. Since January 2010, enrollment has remained relatively steady, with a net decline of three accounts. As indicated in Table 2-1, the largest number of accounts is from the manufacturing sector (55% of the total).

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

Industry	Number of Accounts
Agriculture, Mining & Construction	63
Manufacturing	341
Wholesale, Transport & Other Utilities	66
Retail Stores	38
Offices, Hotels, Finance & Services	39
Schools	69
Institutional/Government	9
Total	**626**

SCE's service territory includes three CAISO local capacity areas (LCA).[5] The vast majority of service accounts (525 out of the 626 BIP accounts) are in the LA Basin LCA; 78 are located in the Ventura LCA and the remaining 23 are in the Outside LA Basin LCA.

In the ex ante analysis, it is assumed that enrollment remains the same from 2011 through 2021. Considering that SCE is close to its cap on emergency DR programs, they do not plan to actively recruit new BIP customers.

SCE did not have any BIP events in 2010. Ex post analysis for the last SCE event was provided in the 2009 statewide load impact evaluation of BIP.[6]

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 of January 1, 2011, there were 189 accounts[7] enrolled in PG&E's BIP program. As in SCE's program, enrollment has remained relatively steady over the past year. Since January 2010, the number of participants has grown by one account. Table 2-2 shows the distribution of service accounts by industry grouping. The largest number of accounts comes from the manufacturing sector (38% of the total).

[5] 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.

[6] Stephen George, Josh Bode and Josh Schellenberg. "2009 Load Impact Evaluation of California's Statewide Base Interruptible Program." April 1, 2010.

[7] 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	27
Manufacturing	72
Wholesale, Transport & Other Utilities	43
Retail Stores	24
Offices, Hotels, Finance & Services	12
Schools	1
Institutional/Government	10
Total	**189**

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	47
Greater Fresno	10
Humboldt	7
Kern	20
Northern Coast	20
Other	71
Sierra	6
Stockton	8
Total	**189**

PG&E plans to increase enrollment in its BIP program over the next few years. In July 2011, PG&E BIP enrollment is expected to equal 198 participants and 243 in July 2014, which is nearly 8% growth per year. From 2014 to 2019, enrollment growth is expected to slow to less than 2% per year, reaching 266 participants in July 2019. Afterwards, enrollment is assumed to remain relatively constant at around 267 customers until the end of the ex ante forecast period (2021).

There was one test event held for PG&E's BIP program in 2010. That event occurred on August 24th and lasted for two hours, from 3 PM to 5 PM. The ex post analysis for PG&E, presented in Section 5.1, pertains to this single event.

2.4 Overview of SDG&E's BIP Program

SDG&E BIP is a voluntary program that offers participants a monthly capacity bill credit in exchange for committing to reduce their demand to a contracted FSL on short notice during emergency situations. 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.

Participation in SDG&E's program has been relatively low and was not open to new customers for an extended period of time. 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. All but one of these accounts is enrolled in option A. The current distribution of accounts by industry is shown in Table 2-4. In contrast to SCE and PG&E, the largest proportion of SDG&E BIP customers is in the offices, hotels, finance & services segment. 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	0
Manufacturing	7
Wholesale, Transport & Other Utilities	1
Retail Stores	4
Offices, Hotels, Finance & Services	9
Schools	0
Institutional/Government	0
Total	**21**

SDG&E plans to increase enrollment in its BIP program over the next few years. In May 2011, SDG&E BIP enrollment is expected to equal 26 participants and 55 in May 2014. Afterwards, enrollment is assumed to remain constant until the end of the ex ante forecast period (2021).

There was one test event held for SDG&E's BIP program in 2010. That event occurred on September 27th and lasted for four hours for option A customers (2 PM to 6 PM) and three hours for option B customers (3 PM to 6 PM). The six BIP customers that were dually-enrolled in CPP were not called for the BIP event because there was a CPP event on the same day. Section 6.1 presents the ex post analysis for the 2010 SDG&E BIP event.

2.5 TA&TI and Auto-DR

Technical Assistance & Technology Incentives (TA&TI) and Auto Demand Response (Auto-DR) are separate programs that facilitate demand reductions for customers that would like to enroll in a DR program or customers that are already enrolled in a DR program. For the 2010 BIP evaluation, there is no TA&TI or Auto-DR analysis because SCE did not call an event in 2010. PG&E and SDG&E called an event in 2010, but these utilities do not offer TA&TI or Auto-DR assistance for BIP customers. In the 2009 evaluation, the impact was analyzed for customers that received TA&TI and Auto-DR assistance between the 2006 and 2009 SCE BIP events. The results were inconclusive due to a lack of statistical power. For more information, see Appendix A, which provides the TA&TI and Auto-DR analysis section from the 2009 BIP report.

2.6 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 (if applicable) 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 and ex ante load impact estimates for BIP. The first two parts cover the regression model development and assessment of its accuracy. The section concludes with a discussion of how the over/under performance adjustment was developed and how it was applied to the ex ante estimates.

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 evidence 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 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. More details on the over/under performance adjustment are provided in Section 3.3.

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 two years of hourly load data 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. Mathematically, the regression model can be expressed as:

$$
\begin{aligned}
kW_t = {} & A + B \times SummerOn_t + C \times SummerMid_t + D \times SummerOff_t + E \times WinterMid_t \\
& + \sum_{i=1}^{24}\sum_{j=1}^{5} F_{ij} \times Hour_i \times DayType_j + \sum_{i=1}^{24}\sum_{j=1}^{12} G_{ij} \times Hour_i \times Month_j \\
& + \sum_{i=1}^{24} H_i \times Hour_i \times Year2010_t + \sum_{i=1}^{24} I_{ij} \times Hour_i \times TotalCDH_t \\
& + \sum_{i=1}^{24} J_{ij} \times Hour_i \times TotalCDHsqr_t + \sum_{i=1}^{24} K_{ij} \times Hour_i \times TotalHDH_t \\
& + \sum_{i=1}^{24} L_{ij} \times Hour_i \times TotalHDHsqr_t + \sum_{i=1}^{24} M_i \times Hour_i \times Other\_Eventday_t \\
& + \sum_{i=1}^{24}\sum_{j=1}^{2} N_{ij} \times Hour_i \times BIP\_Eventday_j + e_t
\end{aligned}
$$

Table 3-1:
Variable Descriptions

Variable	Description
kW_t	hourly BIP customer load at time t
A	estimated constant term
B through N_{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
$Year2010_t$	binary variable for the most recent year of load data
$TotalCDH_t$	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;[8]
e_t	error term

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

Load was significantly lower in 2009 and 2010 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 2009 and 2010 levels. 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 2011 through 2014 and then reach a steady state from 2015 through 2021;
- PG&E: BIP load is also assumed to increase by 1.5% per year from 2011 through 2014 and then *decrease* by 0.6% per year from 2015 through 2021; 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 2011 through 2021.

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. 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.

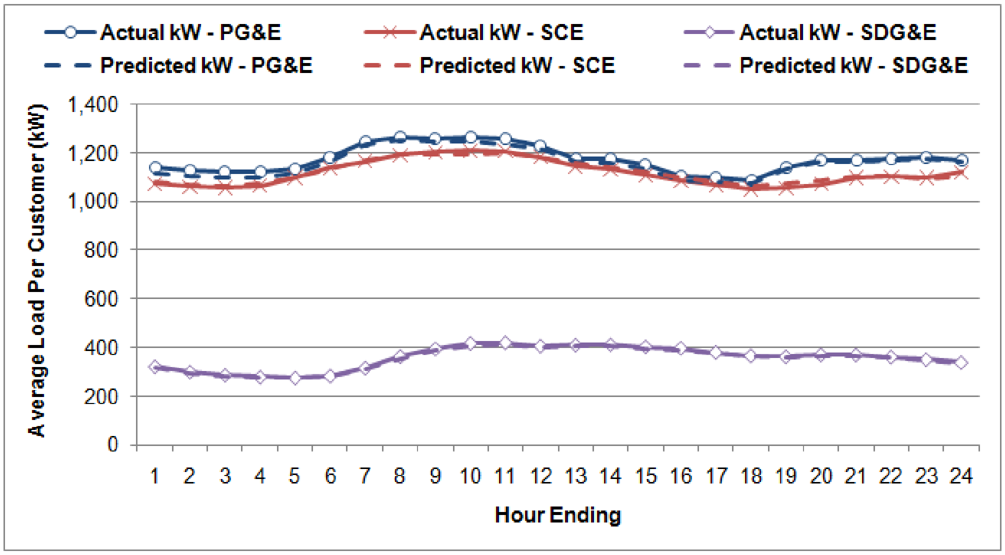
3.2.1 Out-of-Sample Validation

Considering that BIP events are usually called on high system load days during the summer, it is important that the model predicts accurately at high temperatures. 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 five randomly selected high temperature weekdays is withheld from the estimation. Although these five 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 out-of-sample predictions of load are generated for the top 15 maximum temperature weekdays 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 temperature weekdays 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 15 maximum temperature weekdays for each customer. As seen in the figure, the model accurately predicts load on high temperature weekdays even if those days are not included in the estimating sample. The difference between actual and predicted load did not exceed 2.3% 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 slightly over predicts by 1.2%, whereas the PG&E and SDG&E models under predict by less than 1.5%. Considering that BIP customers typically drop more than 70% of their load during events, an error of 1.2% to 1.5% 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 15 Maximum Temperature Weekdays[9]



3.2.2 Goodness of Fit Measures

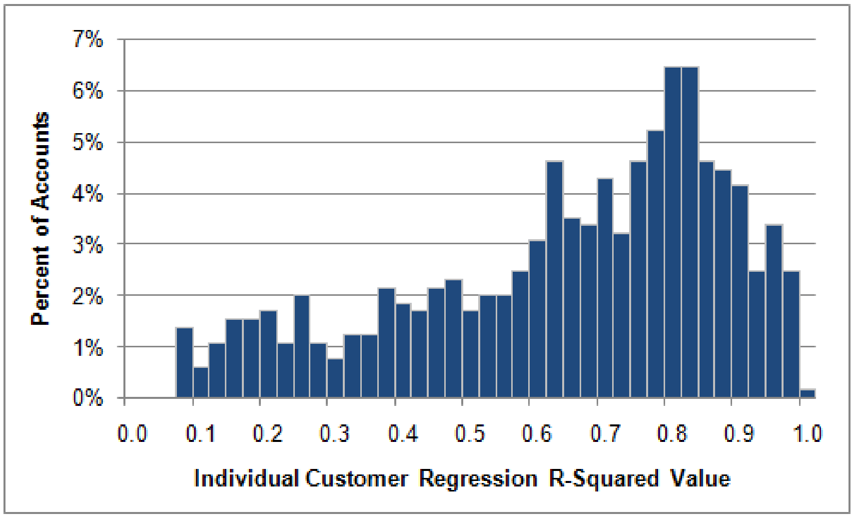
Although regressions were estimated at the individual customer level, from a policy standpoint, the focus is less on how the regressions perform for individual customers than it is on how the regressions perform for the average participant and for specific customer segments. Overall, individual customers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

Figure 3-2 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,

[9] 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 B.

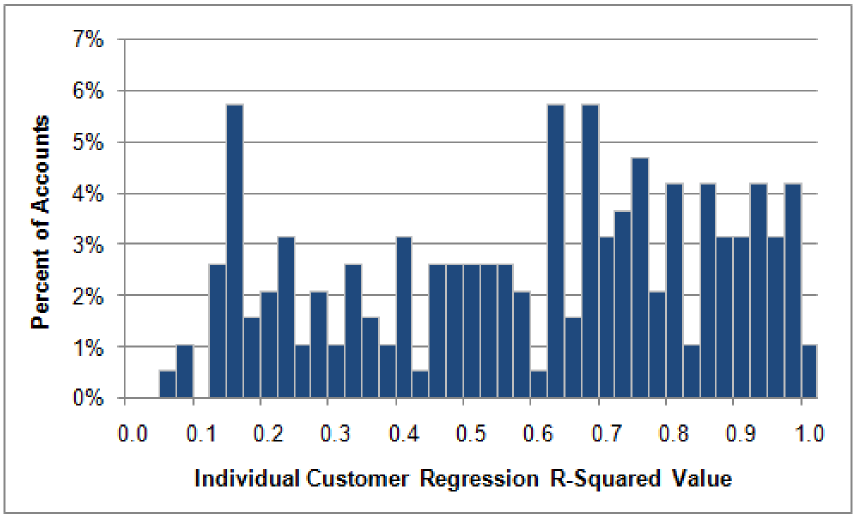
which suggests that the model predicts well for most SCE BIP customers. The lower one-third of all individual regressions had R-squared statistics up to 0.6.

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



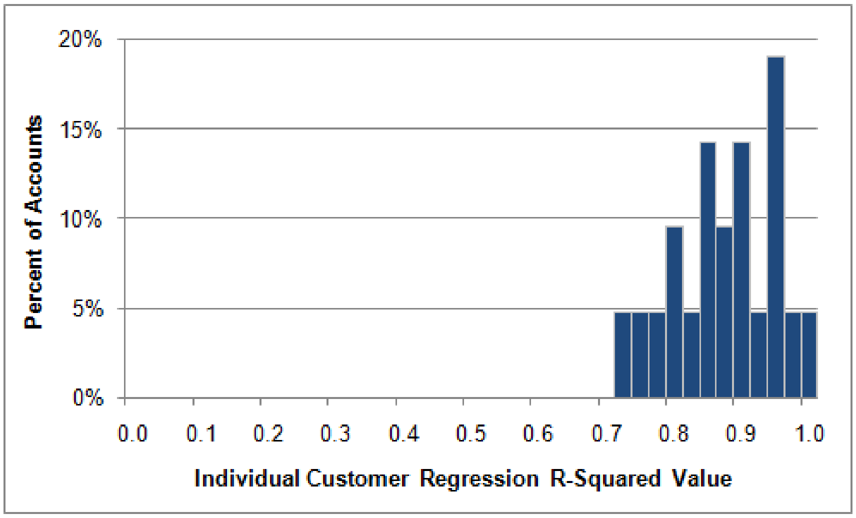
For PG&E BIP customers, the distribution of R-squared values from the individual customer regressions is more variable, as shown in Figure 3-3. About 65% of the individual customer regressions had R-squared values above 0.5. This result suggests that the model explains most of the variation in load for the majority of PG&E BIP customers, but compared to SCE, there are relatively lower values in the bottom group. The lower one-third of all PG&E individual regressions had R-squared statistics below 0.45. 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 0.7.

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:[10]

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

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

[10] 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 3-3 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 0.75, which means that the model explains 75% 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 0.93. Retail stores have the highest aggregate R-squared value for each utility, ranging from 0.95 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 for SCE and PG&E.

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

Industry	SCE	PG&E	SDG&E
Agriculture, Mining & Construction	0.21	0.71	
Manufacturing	0.73	0.68	0.90
Wholesale, Transport & Other Utilities	0.37	0.48	
Retail Stores	0.95	0.99	0.97
Offices, Hotels, Finance & Services	0.87	0.85	0.93
Schools	0.91		
Institutional/Government	0.89	0.95	
All Customers	**0.75**	**0.75**	**0.93**

Table 3-4 shows the aggregate R-Squared values by LCA. The explained variation varied from 32% to 93% across LCAs. Only 2 of the LCAs have an R-squared value below 0.55 – outside LA basin (0.32) and Ventura (0.35). As shown in Table 3-1, the model has a relatively low R-squared for agriculture, mining & construction and wholesale, transport & other utilities customers at SCE. These two industries comprise 50% and 40% of the customer mix in the Outside LA Basin and Ventura LCAs, respectively, which explains why the R-squared is relatively low. For PG&E, the majority of variation in aggregate load is explained in each LCA (i.e., the R-squared value is greater than 0.5).

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

Local Capacity Area	R-Squared
SCE LCAs	
LA Basin	0.77
Outside LA Basin	0.32
Ventura	0.35
PG&E LCAs	
Greater Bay Area	0.79
Greater Fresno	0.78
Humboldt	0.68
Kern	0.55
Northern Coast	0.78
Other	0.67
Sierra	0.77
Stockton	0.80
San Diego	0.93

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. This adjustment was only made for the SCE and PG&E ex ante load impact estimates because SDG&E did not have enough BIP customers or event data to model event day behavior by industry.

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 using data pooled across events from 2006 to 2010. Therefore, a customer in a given industry is assumed to perform similar to the recent historical performance of customers in its industry. This adjustment is made at the industry level simply because there is limited (if any) event history from 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 or two 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 section of analysis.

For SCE and PG&E, data was pooled across events from 2006 to 2010. This data included six different event days. The July 24, 2006 event provided load and FSL information for 508 SCE customers and 102 PG&E customers. The August 28, 2008 PG&E test event provided load and FSL information for 141 PG&E customers. The 2009 test events for SCE and PG&E provided data for 648 SCE customers and 165 PG&E customers. Finally, this year's over/under performance analysis was updated with 187 customers that participated in the 2010 PG&E test event. Considering that this 2010 event comprises a small fraction of the overall analysis, the over/under performance results have not changed substantially from last year.

After pooling the event data, the load shape pattern was determined for each industry and incorporated into the ex ante load impact estimates. Table 3-5 shows the results of the over/under performance analysis by industry. 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 90.6% of the expected load reduction given their FSL in the first hour of the event and 93.7% in the last hour of the event. Although customers slightly under performed during event hours, there are substantial impacts in the hour before and after the event.

Performance varies substantially by industry. Customers in the offices, hotels, finance & services segment over perform by up to 5.8% during event hours. Retail stores under perform substantially, only providing up to 40% of the expected load reduction. Customers in the agriculture, mining & construction segment under perform by around 23% during the first and last hour of the event. The two largest BIP industries (manufacturing and wholesale, transport & other utilities) under perform 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, SCE and PG&E ex ante load impact estimates show moderate load shifting to 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 3-5:
BIP Over/Under Performance Percentages by Industry and Event Hour
SCE and PG&E BIP Events from 2006-2010**

Industry	N	% Over/Under Performance			
		Hour Before Event	First Hour of Event	Last Hour of Event	Hour After Event
Agriculture, Mining & Construction	207	19.9	76.3	78.3	65.6
Manufacturing	927	27.7	95.9	99.1	65.4
Wholesale, Transport & Other Utilities	283	32.7	98.0	97.7	50.8
Retail Stores	81	2.6	34.1	40.0	24.7
Offices, Hotels, Finance & Services	121	26.8	100.7	105.8	63.0
Schools	97	4.9	41.3	56.4	38.1
Institutional/Government	33	4.0	93.6	94.3	56.5
All Customers	**1,749**	**25.6**	**90.6**	**93.7**	**62.7**

For SDG&E, the ex ante load impacts are based on the experience of its 2010 BIP event. For all but one BIP customer, September 27, 2010 was their first BIP event day. With little event history, this event day was all that could be used in the ex ante analysis. Section 6 provides more details on how the results of the 2010 ex post analysis for SDG&E were applied to the ex ante load impact estimates.

4 SCE Load Impact Analysis

This section includes 2011-2021 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 ante load impact estimates that are required by the protocols, including uncertainty adjusted estimates, can be found in the electronic appendix titled, “SCE 2010 BIP Ex Ante Load Impact Tables."

4.1 Ex Post Load Impact Estimates

SCE did not have any BIP events in 2010. Ex post analysis of the most recent event in 2009 was conducted in conjunction with the 2009 load impact evaluation of BIP.[11]

4.2 Ex Ante Load Impact Estimates

SCE projects that BIP enrollment will remain constant throughout the ex ante forecast period (2011-2021). 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 2011 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 4-1 and 4-2 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. For a 1-in-2 typical event day, the estimated load impact for the average participant is 908 kW from 1 PM to 6 PM. This represents a 78.1% impact relative to the average reference load of 1,162.2 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 898 kW, which is 1% less than in the 1-in-2 weather year.

[11] Stephen George, Josh Bode and Josh Schellenberg. "2009 Load Impact Evaluation of California's Statewide Base Interruptible Program." April 1, 2010.

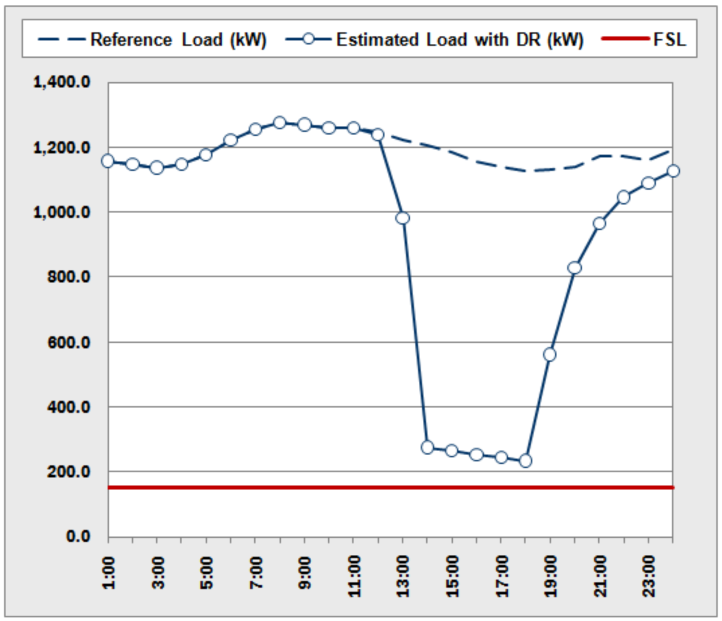
Figure 4-1:
SCE BIP Average Load Impact (kW) per Customer in 2015
for a Typical Event Day Based on 1-in-2 Year Weather Conditions

TABLE 1: Menu options

Type of Results	Average Enrolled Account
Weather Year	1-in-2
Forecast Year	2015-2021
Day Type	Typical Event Day
Customer Characteristic	All Customers

TABLE 2: Output

Number of Accounts	626
Average FSL (kW)	151.1
Proxy Date	N/A
Average Load Impact (kW) (1-6pm)	908.0
% Load Impact (1-6pm)	78.1%



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	1157.0	1157.0	0.0	69.3	-56.7	-23.2	0.0	23.2	56.7
2:00	1146.1	1146.1	0.0	68.3	-56.7	-23.2	0.0	23.2	56.7
3:00	1136.4	1136.4	0.0	67.0	-56.7	-23.2	0.0	23.2	56.7
4:00	1148.6	1148.6	0.0	66.4	-56.7	-23.2	0.0	23.2	56.7
5:00	1177.4	1177.4	0.0	65.5	-56.7	-23.2	0.0	23.2	56.7
6:00	1221.6	1221.6	0.0	65.0	-56.8	-23.2	0.0	23.2	56.8
7:00	1254.9	1254.9	0.0	65.6	-56.8	-23.2	0.0	23.2	56.8
8:00	1275.9	1275.9	0.0	69.0	-56.8	-23.2	0.0	23.2	56.8
9:00	1269.0	1269.0	0.0	74.6	-56.7	-23.2	0.0	23.2	56.7
10:00	1260.4	1260.4	0.0	79.8	-56.6	-23.2	0.0	23.2	56.6
11:00	1259.8	1259.8	0.0	84.1	-56.5	-23.1	0.0	23.1	56.5
12:00	1247.9	1239.8	8.1	87.3	-48.3	-15.0	8.1	31.2	64.6
13:00	1222.9	982.3	240.5	89.7	184.1	217.4	240.5	263.6	297.0
14:00	1207.4	275.2	932.2	91.4	875.8	909.1	932.2	955.3	988.6
15:00	1183.7	264.6	919.1	92.1	862.7	896.0	919.1	942.1	975.5
16:00	1157.6	253.8	903.8	92.1	847.4	880.7	903.8	926.8	960.2
17:00	1137.5	243.6	893.9	91.1	837.6	870.9	893.9	917.0	950.3
18:00	1124.7	233.8	890.9	88.9	834.5	867.8	890.9	913.9	947.3
19:00	1131.7	561.1	570.6	85.7	514.2	547.5	570.6	593.6	627.0
20:00	1137.8	828.6	309.2	81.9	252.8	286.1	309.2	332.3	365.6
21:00	1170.2	964.0	206.1	77.8	149.4	182.9	206.1	229.3	262.9
22:00	1172.2	1046.5	125.7	75.3	69.0	102.5	125.7	149.0	182.5
23:00	1159.8	1088.9	70.9	73.4	14.2	47.7	70.9	94.1	127.7
0:00	1192.5	1127.4	65.1	71.5	8.4	41.9	65.1	88.3	121.8
	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	28,553.1	22,416.9	6,136.2	216.8	5858.9	6022.7	6136.2	6249.6	6413.4

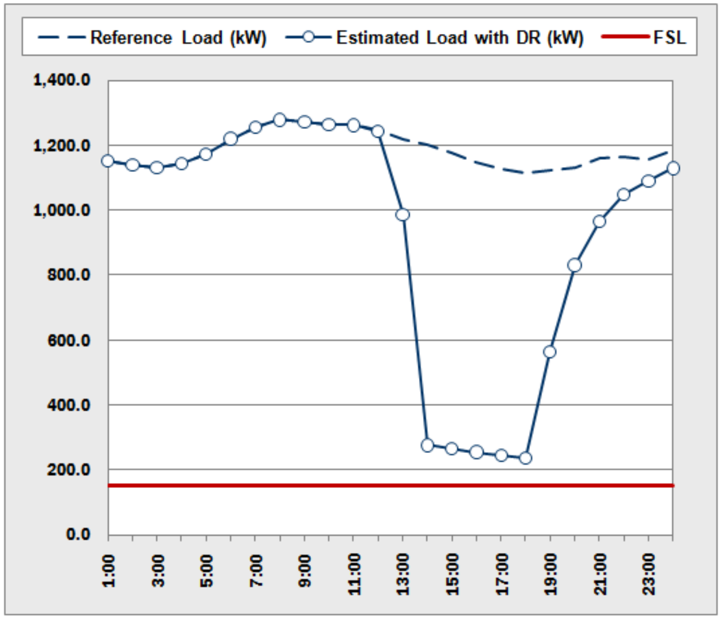
Figure 4-2:
SCE BIP Average Load Impact (kW) per Customer in 2015
for a Typical Event Day Based on 1-in-10 Year Weather Conditions

TABLE 1: Menu options

Type of Results	Average Enrolled Account
Weather Year	1-in-10
Forecast Year	2015-2021
Day Type	Typical Event Day
Customer Characteristic	All Customers

TABLE 2: Output

Number of Accounts	626
Average FSL (kW)	151.1
Proxy Date	N/A
Average Load Impact (kW) (1-6pm)	898.0
% Load Impact (1-6pm)	77.9%



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	1151.2	1151.2	0.0	76.3	-57.2	-23.4	0.0	23.4	57.2
2:00	1140.2	1140.2	0.0	74.8	-57.2	-23.4	0.0	23.4	57.2
3:00	1129.5	1129.5	0.0	73.8	-57.3	-23.5	0.0	23.5	57.3
4:00	1142.1	1142.1	0.0	72.9	-57.3	-23.4	0.0	23.4	57.3
5:00	1173.3	1173.3	0.0	72.3	-57.3	-23.4	0.0	23.4	57.3
6:00	1219.4	1219.4	0.0	71.9	-57.3	-23.4	0.0	23.4	57.3
7:00	1254.3	1254.3	0.0	72.1	-57.3	-23.4	0.0	23.4	57.3
8:00	1278.2	1278.2	0.0	74.7	-57.3	-23.4	0.0	23.4	57.3
9:00	1271.9	1271.9	0.0	79.1	-57.1	-23.4	0.0	23.4	57.1
10:00	1262.2	1262.2	0.0	83.1	-57.0	-23.3	0.0	23.3	57.0
11:00	1261.9	1261.9	0.0	86.3	-56.9	-23.3	0.0	23.3	56.9
12:00	1246.5	1242.7	3.8	88.7	-53.0	-19.5	3.8	27.1	60.6
13:00	1218.2	986.3	231.9	90.9	175.1	208.6	231.9	255.1	288.7
14:00	1200.9	276.0	924.9	92.5	868.1	901.6	924.9	948.1	981.7
15:00	1177.4	266.2	911.2	93.3	854.4	888.0	911.2	934.4	968.0
16:00	1148.0	254.7	893.3	93.0	836.6	870.1	893.3	916.6	950.1
17:00	1126.7	244.2	882.5	91.7	825.7	859.3	882.5	905.7	939.3
18:00	1113.7	235.7	878.0	89.4	821.3	854.8	878.0	901.3	934.8
19:00	1121.4	563.3	558.0	86.2	501.3	534.8	558.1	581.3	614.8
20:00	1130.1	830.7	299.4	82.0	242.6	276.2	299.4	322.7	356.3
21:00	1160.9	966.1	194.8	78.4	137.6	171.4	194.8	218.1	251.9
22:00	1162.9	1048.7	114.2	76.3	57.1	90.9	114.2	137.6	171.4
23:00	1155.1	1090.3	64.9	74.5	7.7	41.5	64.9	88.3	122.1
0:00	1185.3	1129.2	56.1	73.4	-1.2	32.7	56.1	79.6	113.5
	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	28,431.5	22,418.3	6,013.2	267.7	5733.7	5898.8	6013.2	6127.5	6292.6

Table 4-1 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 2021 time period, the program is expected to be capable of delivering up to 613.4 MW, which occurs during the May 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 536.3 MW in 2011 to 568.4 MW in 2015-2021. This percentage growth of 6% from 2011 to 2015 is similar across all of the day types.

Table 4-1:
SCE BIP Aggregate On-Peak Load Impacts (MW)
for Each Day Type by Weather Year and Forecast Year

Weather Year	Day Type	Peak Period	2011	2012	2013	2014	2015-2021
1-in-2	Typical Event Day	1-6 PM	536.3	545.5	554.9	564.4	568.4
	January Peak	4-9 PM	492.2	500.6	509.1	517.8	526.6
	February Peak	4-9 PM	517.7	526.6	535.6	544.7	553.2
	March Peak	4-9 PM	487.7	496.0	504.5	513.2	520.4
	April Peak	1-6 PM	544.7	554.0	563.5	573.1	580.4
	May Peak	1-6 PM	575.4	585.2	595.1	605.2	612.1
	June Peak	1-6 PM	544.0	553.2	562.7	572.3	577.9
	July Peak	1-6 PM	533.5	542.7	552.0	561.4	566.2
	August Peak	1-6 PM	533.4	542.5	551.9	561.3	565.3
	September Peak	1-6 PM	539.0	548.2	557.6	567.1	570.4
	October Peak	1-6 PM	569.9	579.6	589.4	599.4	601.9
	November Peak	4-9 PM	523.1	532.0	541.1	550.3	551.8
	December Peak	4-9 PM	448.6	456.4	464.3	472.3	473.0
1-in-10	Typical Event Day	1-6 PM	530.3	539.5	548.8	558.2	562.1
	January Peak	4-9 PM	483.4	491.7	500.1	508.7	517.4
	February Peak	4-9 PM	537.9	547.1	556.4	565.9	574.7
	March Peak	4-9 PM	526.1	535.1	544.2	553.5	561.3
	April Peak	1-6 PM	548.0	557.4	566.9	576.5	583.9
	May Peak	1-6 PM	576.6	586.5	596.5	606.6	613.4
	June Peak	1-6 PM	537.4	546.6	556.0	565.5	571.1
	July Peak	1-6 PM	526.7	535.8	545.0	554.3	559.0
	August Peak	1-6 PM	529.7	538.8	548.1	557.5	561.5
	September Peak	1-6 PM	536.0	545.2	554.6	564.0	567.2
	October Peak	1-6 PM	571.8	581.6	591.5	601.6	604.1
	November Peak	4-9 PM	525.5	534.5	543.6	552.9	554.5
	December Peak	4-9 PM	453.4	461.2	469.2	477.3	477.9

Table 4-2 provides the 2015-2021 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 418.9 MW aggregate load impact, which accounts for 73.7% of the total for all customers. The Outside LA Basin LCA has the largest average load impact per customer (2,562.5 kW). As a result, the Outside LA Basin LCA accounts for 10.4% of the total aggregate load impact even though it has less than 4% of the total number of customers. The remaining 15.9% of the total aggregate load impact is located in the Ventura LCA.

Table 4-2:
2015-2021 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 Total Aggregate Load Impact
LA Basin	525	1,047.4	249.5	797.9	418.9	73.7
Outside LA Basin	23	2,952.0	389.5	2,562.5	59.1	10.4
Ventura	78	1,405.8	245.8	1,160.0	90.3	15.9
All Customers	**626**	**1,162.2**	**254.2**	**908.0**	**568.4**	**100.0**

5 PG&E Load Impact Analysis

This section includes 2010 ex post load impact estimates and 2011-2021 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 2010 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 in this section are for PG&E's BIP program for the test event that occurred on August 24, 2010. That event lasted from 3 PM to 5 PM. It was a test event that included all of the 189 customers that were enrolled in BIP at that time.

Figure 5-1 shows the average load impact per customer in each hour on August 24th. As seen, the average load drop over the two-hour event period was 787.9 kW. In the hour prior to the event, the average load reduction equaled 362.9 kW, and in the first hour after the event, load was still more than 490 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 148.9 MW. This represents roughly a 76% reduction relative to the reference load of 196.6 MW. The event-period load of 47.7 MW is slightly higher than the aggregate FSL of 39.2 MW. BIP customers slightly under performed, reducing load by roughly 5% less than what was required to meet their FSL commitments.

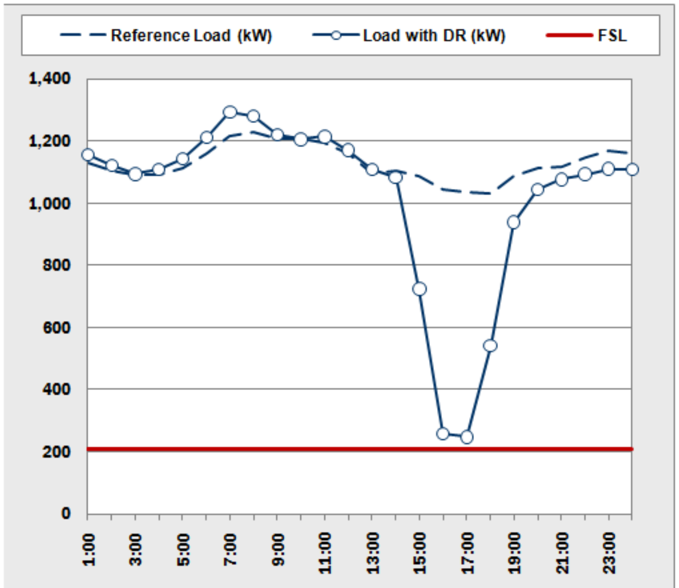
Figure 5-1:
Average Ex Post Load Impact (kW) per Participant for PG&E BIP Event (August 24. 2010)

TABLE 1: Menu options

Type of Results	Average Enrolled Account
Event	Tuesday, August 24, 2010
Customer Characteristic	All Customers

TABLE 2: Output

Number of Accounts	189
Average FSL (kW)	207.6



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	1131.1	1154.7	-23.6	71.3	-93.2	-52.1	-23.6	4.8	45.9
2:00	1103.8	1120.1	-16.3	69.8	-85.8	-44.7	-16.3	12.2	53.3
3:00	1092.8	1093.3	-0.5	68.8	-70.0	-29.0	-0.5	28.0	69.0
4:00	1090.6	1108.7	-18.1	67.5	-87.7	-46.6	-18.1	10.3	51.4
5:00	1114.2	1142.2	-27.9	66.1	-97.5	-56.4	-27.9	0.5	41.6
6:00	1158.0	1210.8	-52.8	65.1	-122.3	-81.2	-52.8	-24.3	16.8
7:00	1213.6	1292.0	-78.4	64.6	-147.9	-106.8	-78.4	-49.9	-8.8
8:00	1229.1	1279.0	-49.9	66.9	-119.4	-78.3	-49.9	-21.4	19.7
9:00	1205.5	1218.3	-12.8	72.9	-82.4	-41.3	-12.8	15.6	56.7
10:00	1207.4	1204.8	2.6	78.7	-67.0	-25.9	2.6	31.0	72.1
11:00	1193.5	1213.3	-19.8	84.1	-89.3	-48.2	-19.8	8.7	49.8
12:00	1161.5	1170.1	-8.6	88.4	-78.1	-37.0	-8.6	19.9	61.0
13:00	1095.3	1109.1	-13.8	92.3	-83.3	-42.2	-13.8	14.7	55.8
14:00	1105.7	1081.4	24.3	95.0	-45.3	-4.2	24.3	52.7	93.8
15:00	1086.4	723.5	362.9	97.4	293.3	334.4	362.9	391.3	432.4
16:00	1043.5	257.7	785.9	98.8	716.3	757.4	785.9	814.3	855.4
17:00	1037.0	247.1	789.9	99.5	720.4	761.4	789.9	818.4	859.4
18:00	1031.5	539.9	491.6	98.9	422.1	463.2	491.6	520.1	561.2
19:00	1085.0	937.8	147.2	96.8	77.7	118.8	147.2	175.7	216.8
20:00	1113.0	1043.6	69.4	92.6	-0.1	41.0	69.4	97.9	139.0
21:00	1117.5	1075.9	41.6	87.2	-28.0	13.1	41.6	70.0	111.1
22:00	1147.1	1092.6	54.5	83.7	-15.1	26.0	54.5	82.9	124.0
23:00	1166.1	1110.0	56.1	81.1	-13.4	27.7	56.1	84.6	125.7
0:00	1157.6	1106.8	50.8	78.7	-18.7	22.3	50.8	79.3	120.3
	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	27,086.9	24,532.6	2,554.3	307.4	2213.6	2414.9	2554.3	2693.7	2895.0

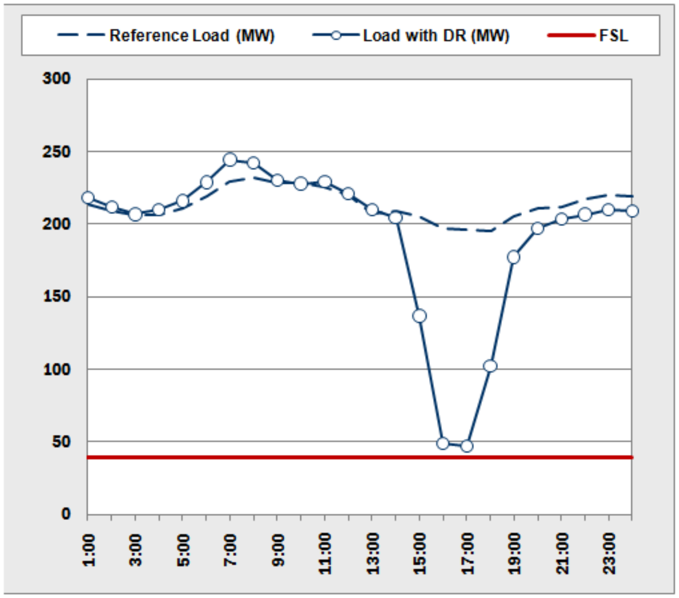
Figure 5-2:
Aggregate Load Impact (MW) for PG&E BIP Event (August 24, 2010)

TABLE 1: Menu options

Type of Results	Aggregate
Event	Tuesday, August 24, 2010
Customer Characteristic	All Customers

TABLE 2: Output

Number of Accounts	189
Aggregate FSL (MW)	39.2



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	213.8	218.2	-4.5	71.3	-17.6	-9.8	-4.5	0.9	8.7
2:00	208.6	211.7	-3.1	69.8	-16.2	-8.5	-3.1	2.3	10.1
3:00	206.5	206.6	-0.1	68.8	-13.2	-5.5	-0.1	5.3	13.0
4:00	206.1	209.5	-3.4	67.5	-16.6	-8.8	-3.4	2.0	9.7
5:00	210.6	215.9	-5.3	66.1	-18.4	-10.7	-5.3	0.1	7.9
6:00	218.9	228.8	-10.0	65.1	-23.1	-15.4	-10.0	-4.6	3.2
7:00	229.4	244.2	-14.8	64.6	-28.0	-20.2	-14.8	-9.4	-1.7
8:00	232.3	241.7	-9.4	66.9	-22.6	-14.8	-9.4	-4.0	3.7
9:00	227.8	230.3	-2.4	72.9	-15.6	-7.8	-2.4	3.0	10.7
10:00	228.2	227.7	0.5	78.7	-12.7	-4.9	0.5	5.9	13.6
11:00	225.6	229.3	-3.7	84.1	-16.9	-9.1	-3.7	1.6	9.4
12:00	219.5	221.1	-1.6	88.4	-14.8	-7.0	-1.6	3.8	11.5
13:00	207.0	209.6	-2.6	92.3	-15.7	-8.0	-2.6	2.8	10.5
14:00	209.0	204.4	4.6	95.0	-8.6	-0.8	4.6	10.0	17.7
15:00	205.3	136.7	68.6	97.4	55.4	63.2	68.6	74.0	81.7
16:00	197.2	48.7	148.5	98.8	135.4	143.1	148.5	153.9	161.7
17:00	196.0	46.7	149.3	99.5	136.1	143.9	149.3	154.7	162.4
18:00	195.0	102.0	92.9	98.9	79.8	87.5	92.9	98.3	106.1
19:00	205.1	177.3	27.8	96.8	14.7	22.4	27.8	33.2	41.0
20:00	210.4	197.2	13.1	92.6	0.0	7.7	13.1	18.5	26.3
21:00	211.2	203.4	7.9	87.2	-5.3	2.5	7.9	13.2	21.0
22:00	216.8	206.5	10.3	83.7	-2.8	4.9	10.3	15.7	23.4
23:00	220.4	209.8	10.6	81.1	-2.5	5.2	10.6	16.0	23.8
0:00	218.8	209.2	9.6	78.7	-3.5	4.2	9.6	15.0	22.7
	Reference Energy Use (MWh)	Energy Use with DR (MWh)	Change in Energy Use (MWh)	Cooling Degree Hours (Base 70)	Uncertainty Adjusted Impact - Percentiles				
					10th	30th	50th	70th	90th
Daily	5,119.4	4,636.7	482.8	307.4	418.4	456.4	482.8	509.1	547.2

Table 5-1 shows the average load impact per customer across the event period by industry group and Table 5-2 shows the aggregate impact by industry. 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%. Retail stores under performed substantially, only providing 26.3% of the expected load reduction. Customers in the manufacturing and agriculture, mining & construction segments provided the largest percentage load drop (around 82% of the reference load). In aggregate, the manufacturing sector provided 68.4% of the total load reduction on the event day. This result is consistent with last year's ex post evaluation, where manufacturing customers provided 68% of the aggregate load reduction for the August 28, 2009 event.

Table 5-1:
Average Customer Load Impact by Industry for August 24, 2010 PG&E Event

Industry	Number of Customers	Reference Load (kW)	Load with DR (kW)	Load Reduction (kW)	Average FSL (kW)	Performance (%)
Agriculture, Mining & Construction	27	693.4	119.2	574.2	223.5	122.2
Manufacturing	70	1784.1	328.4	1455.7	236.8	94.1
Wholesale, Transport & Other Utilities	44	520.1	158.7	361.3	195.7	111.4
Retail Stores	25	229.5	189.1	40.4	76.0	26.3
Offices, Hotels, Finance & Services	12	1697.4	633.8	1063.6	482.1	87.5
Institutional/Government	9	273.5	164.4	109.1	23.9	43.7
All Customers	**189**	**1040.2**	**252.4**	**787.9**	**207.6**	**94.6**

Table 5-2:
Aggregate Load Impact by Industry for August 24, 2010 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	27	18.7	3.2	15.5	82.8	10.4
Manufacturing	70	124.9	23.0	101.9	81.6	68.4
Wholesale, Transport & Other Utilities	44	22.9	7.0	15.9	69.5	10.7
Retail Stores	25	5.7	4.7	1.0	17.6	0.7
Offices, Hotels, Finance & Services	12	20.4	7.6	12.8	62.7	8.6
Institutional/Government	9	2.5	1.5	1.0	39.9	0.7
All Customers	**189**	**196.6**	**47.7**	**148.9**	**75.7**	**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 20 or fewer accounts enrolled in BIP at the time of the event. Around 37% of all accounts were located in the Other LCA and nearly 24% in the Greater Bay Area LCA. Half of the customers in the manufacturing segment are located in the Other LCA. This concentration of manufacturing customers explains why the average load reduction in the Other LCA is nearly 1 MW higher than in the other areas. As a result, the Other LCA accounted for 72.8% of the aggregate load reduction. This result is consistent with last year's ex post evaluation, where customers in the Other LCA provided 70% of the aggregate load reduction for the August 28, 2009 event.

Percent load reductions and performance relative to the FSL vary substantially by LCA. Customers in the Humboldt and Kern LCAs complied with their FSL and provided a load reduction of over 100%. In the Other LCA, customers under performed slightly and provided a 79.9% load reduction. Performance relative to the FSL is not applicable to customers in the Sierra LCA because the reference load is nearly even with the FSL during the event. Although average summer on-peak demand for Sierra customers is nearly double the FSL, average load from 3 PM to 5 PM is close to the FSL. Basically, customers in the Sierra LCA have highly variable hourly load and their aggregate impact depends heavily on the specific timing of the event. If the event were called two hours earlier, the reference load would have been nearly double.

Table 5-3:
Average Customer Load Impact by Local Capacity Area for August 24, 2010 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	46	655.7	274.4	381.2	202.3	84.1
Greater Fresno	13	403.4	223.3	180.1	114.9	62.4
Humboldt	7	505.6	22.4	483.2	25.7	100.7
Kern	20	625.8	60.5	565.3	108.5	109.3
Northern Coast	19	382.5	108.4	274.1	70.2	87.8
Other	70	1936.9	389.0	1547.9	328.7	96.2
Sierra	6	152.6	39.0	113.6	146.0	N/A
Stockton	8	396.5	193.8	202.7	138.1	78.5
All Customers	**189**	**1040.2**	**252.4**	**787.9**	**207.6**	**94.6**

Table 5-4:
Aggregate Load Impact by Local Capacity Area for August 24, 2010 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	46	30.2	12.6	17.5	58.1	11.8
Greater Fresno	13	5.2	2.9	2.3	44.7	1.6
Humboldt	7	3.5	0.2	3.4	95.6	2.3
Kern	20	12.5	1.2	11.3	90.3	7.6
Northern Coast	19	7.3	2.1	5.2	71.7	3.5
Other	70	135.6	27.2	108.4	79.9	72.8
Sierra	6	0.9	0.2	0.7	74.4	0.5
Stockton	8	3.2	1.6	1.6	51.1	1.1
All Customers	**189**	**196.6**	**47.7**	**148.9**	**75.7**	**100.0**

5.2 Ex Ante Load Impact Estimates

PG&E plans to increase enrollment in its BIP program over the next few years. In July 2011, PG&E BIP enrollment is expected to equal 198 participants and 243 in July 2014, which is nearly 8% growth per year. From 2014 to 2019, enrollment growth is expected to slow to less than 2% per year, reaching 266 participants in July 2019. Afterwards, enrollment is assumed to remain relatively constant at around 267 customers until the end of the ex ante forecast period (2021).

BIP load growth as the economy improves is another source of variation in ex ante load impacts throughout the forecast period (2011-2021). As discussed in Section 3.1, PG&E BIP load is assumed to increase by 1.5% per year from 2011 through 2014 and then *decrease* by 0.6% per year from 2015 through 2021. This pattern is consistent with PG&E's internal economic forecast of average load for large business customers. The 1.5% annual increase and 0.6% annual decrease are applied to the estimated reference load, which in turn leads to a proportional change in load impacts.

Figures 5-3 and 5-4 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 2014. Impacts are reported for 2014 because it is the year in which BIP load growth reaches its maximum. For a 1-in-2 typical event day, the estimated load impact for the average participant is 965.8 kW from 1 PM to 6 PM. This represents a 79.3% impact relative to the average reference load of 1,218 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 960 kW, which is 0.6% less than in the 1-in-2 weather year.

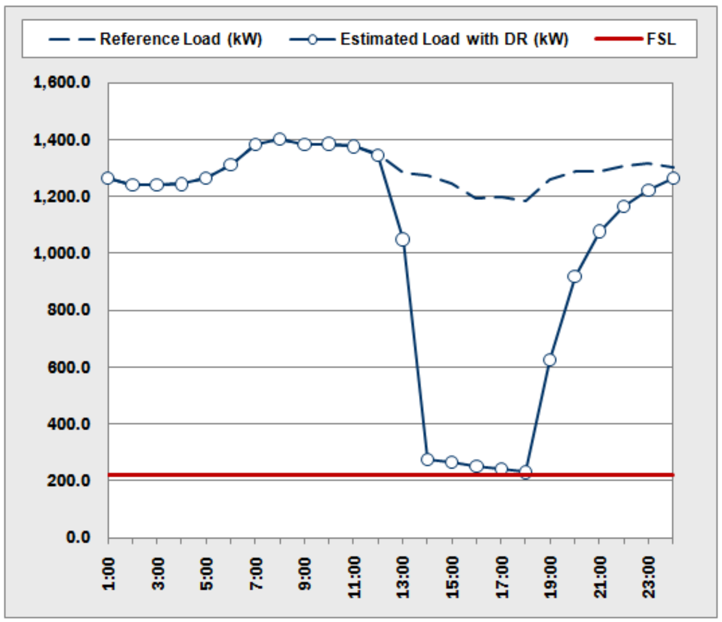
Figure 5-3:
PG&E BIP Average Load Impact (kW) per Customer in 2014
for a Typical Event Day Based on 1-in-2 Year Weather Conditions

TABLE 1: Menu options

Type of Results	Average Enrolled Account
Weather Year	1-in-2
Forecast Year	2014
Day Type	Typical Event Day
Customer Characteristic	All Customers

TABLE 2: Output

Number of Accounts	243
Average FSL (kW)	219.6
Proxy Date	N/A
Average Load Impact (kW) (1-6pm)	965.8
% Load Impact (1-6pm)	79.3%



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	1264.3	1264.3	0.0	71.6	-117.3	-48.0	0.0	48.0	117.3
2:00	1240.7	1240.7	0.0	67.0	-117.2	-48.0	0.0	48.0	117.2
3:00	1239.0	1239.0	0.0	65.5	-117.3	-48.0	0.0	48.0	117.3
4:00	1243.2	1243.2	0.0	64.3	-117.2	-48.0	0.0	48.0	117.2
5:00	1262.8	1262.8	0.0	63.6	-117.2	-48.0	0.0	48.0	117.2
6:00	1311.4	1311.4	0.0	63.0	-117.3	-48.0	0.0	48.0	117.3
7:00	1383.3	1383.3	0.0	63.1	-117.4	-48.1	0.0	48.1	117.4
8:00	1401.7	1401.7	0.0	66.6	-117.5	-48.1	0.0	48.1	117.5
9:00	1382.6	1382.6	0.0	72.2	-117.4	-48.0	0.0	48.0	117.4
10:00	1384.5	1384.5	0.0	77.4	-117.4	-48.0	0.0	48.0	117.4
11:00	1375.8	1375.8	0.0	82.3	-117.4	-48.0	0.0	48.0	117.4
12:00	1349.9	1344.3	5.5	86.6	-111.8	-42.5	5.5	53.5	122.9
13:00	1280.8	1048.5	232.3	89.8	115.1	184.3	232.3	280.3	349.6
14:00	1272.2	274.5	997.8	92.3	880.5	949.8	997.8	1045.8	1115.1
15:00	1243.0	264.9	978.0	94.3	860.8	930.1	978.0	1026.0	1095.2
16:00	1193.9	251.1	942.9	95.2	825.8	895.0	942.9	990.8	1059.9
17:00	1196.7	240.6	956.0	94.8	839.0	908.1	956.0	1003.9	1073.1
18:00	1184.3	230.1	954.1	93.6	837.0	906.2	954.1	1002.0	1071.2
19:00	1257.2	623.7	633.5	91.0	516.4	585.6	633.5	681.4	750.6
20:00	1286.7	919.1	367.6	86.8	250.4	319.7	367.6	415.6	484.8
21:00	1287.8	1076.9	210.8	81.8	93.7	162.9	210.8	258.8	328.0
22:00	1306.2	1165.6	140.7	78.0	23.5	92.7	140.7	188.6	257.8
23:00	1315.4	1222.7	92.7	75.3	-24.5	44.7	92.7	140.7	209.9
0:00	1301.4	1264.5	36.9	73.3	-80.4	-11.1	36.9	84.9	154.2

	Reference Energy Use (kWh)	Energy Use with DR (kWh)	Change in Energy Use (kWh)	Cooling Degree Hours (Base 75)	Uncertainty Adjusted Impact - Percentiles: 10th	30th	50th	70th	90th
Daily	30,964.8	24,415.9	6,548.9	169.0	814.1	4142.2	6548.9	8728.2	12366.6

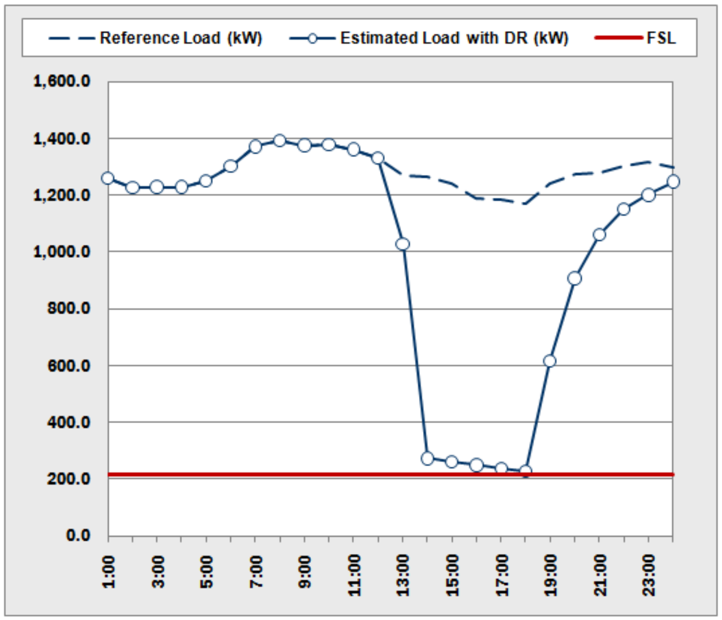
Figure 5-4:
PG&E BIP Average Load Impact (kW) per Customer in 2014
for a Typical Event Day Based on 1-in-10 Year Weather Conditions

TABLE 1: Menu options

Type of Results	Average Enrolled Account
Weather Year	1-in-10
Forecast Year	2014
Day Type	Typical Event Day
Customer Characteristic	All Customers

TABLE 2: Output

Number of Accounts	243
Average FSL (kW)	216.5
Proxy Date	N/A
Average Load Impact (kW) (1-6pm)	960.0
% Load Impact (1-6pm)	79.4%



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	1259.7	1259.7	0.0	75.4	-121.2	-49.6	0.0	49.6	121.2
2:00	1225.4	1225.4	0.0	74.1	-120.7	-49.4	0.0	49.4	120.7
3:00	1228.3	1228.3	0.0	72.9	-121.1	-49.5	0.0	49.5	121.1
4:00	1227.6	1227.6	0.0	71.6	-120.9	-49.5	0.0	49.5	120.9
5:00	1250.0	1250.0	0.0	70.7	-121.0	-49.5	0.0	49.5	121.0
6:00	1301.2	1301.2	0.0	69.8	-121.1	-49.5	0.0	49.5	121.1
7:00	1370.7	1370.7	0.0	69.6	-121.4	-49.7	0.0	49.7	121.4
8:00	1392.0	1392.0	0.0	72.1	-121.2	-49.6	0.0	49.6	121.2
9:00	1374.6	1374.6	0.0	77.2	-121.5	-49.7	0.0	49.7	121.5
10:00	1377.7	1377.7	0.0	81.8	-121.7	-49.8	0.0	49.8	121.7
11:00	1360.6	1360.6	0.0	86.0	-121.9	-49.9	0.0	49.9	121.9
12:00	1331.2	1329.8	1.4	89.7	-120.2	-48.4	1.4	51.2	123.0
13:00	1267.7	1027.9	239.8	93.0	117.8	189.9	239.8	289.7	361.8
14:00	1265.7	272.7	993.0	95.4	870.8	943.0	993.0	1043.0	1115.2
15:00	1238.2	260.4	977.8	96.9	856.3	928.1	977.8	1027.6	1099.4
16:00	1187.3	248.7	938.6	97.9	817.3	888.9	938.6	988.2	1059.9
17:00	1184.4	238.2	946.1	98.1	824.9	896.5	946.1	995.7	1067.3
18:00	1171.5	226.9	944.5	97.2	823.7	895.1	944.5	994.0	1065.4
19:00	1241.8	614.1	627.7	94.7	507.1	578.3	627.7	677.1	748.3
20:00	1273.9	907.1	366.7	90.9	245.6	317.2	366.7	416.3	487.9
21:00	1278.5	1061.5	217.0	86.5	96.2	167.6	217.0	266.5	337.9
22:00	1301.7	1149.3	152.4	83.2	31.3	102.8	152.4	201.9	273.4
23:00	1314.1	1200.4	113.8	80.7	-7.8	64.0	113.8	163.5	235.3
0:00	1297.3	1246.6	50.7	79.0	-71.4	0.7	50.7	100.7	172.9
	Reference Energy Use (kWh)	Energy Use with DR (kWh)	Change in Energy Use (kWh)	Cooling Degree Hours (Base 75)	Uncertainty Adjusted Impact - Percentiles				
					10th	30th	50th	70th	90th
Daily	30,721.1	24,151.5	6,569.6	228.6	754.3	4126.2	6569.6	8784.5	12478.5

Table 5-5 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. The change in peak period timing does not affect PG&E BIP customers substantially because they have a relatively flat load shape, as shown in Figures 5-3 and 5-4. Throughout the forecast period (2011-2021), the program is expected to be capable of delivering up to 266.6 MW, which occurs during the October monthly peak under 1-in-10 weather conditions in 2017. The aggregate load impacts drop off slightly from 2017 to 2021 because enrollment growth slows while BIP load is assumed to decrease by 0.6% per year. As a result of net load growth[12] and new enrollment, aggregate load impacts increase by 23% to 37% for each day type from 2011 to 2021. For the July monthly peak day in a 1-in-2 weather year, aggregate load impacts increase by 31%, growing from 181.8 MW in 2011 to 238.3 MW in 2021.

Table 5-5:
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	2011	2012	2014	2017	2021
1-in-2	Typical Event Day	1-6 PM	181.9	205.5	234.4	245.7	238.3
	January Peak	4-9 PM	156.1	172.8	202.5	217.9	213.2
	February Peak	4-9 PM	164.4	183.2	213.4	228.6	223.4
	March Peak	4-9 PM	166.8	186.7	216.2	230.5	224.8
	April Peak	1-6 PM	183.5	206.5	238.1	252.5	245.8
	May Peak	1-6 PM	160.6	181.4	208.7	220.9	215.3
	June Peak	1-6 PM	177.0	200.4	229.4	241.6	234.8
	July Peak	1-6 PM	181.8	205.4	234.3	245.6	238.3
	August Peak	1-6 PM	179.6	202.8	230.6	240.7	233.5
	September Peak	1-6 PM	178.7	201.2	228.1	237.0	229.4
	October Peak	1-6 PM	201.4	226.3	255.9	264.8	255.9
	November Peak	4-9 PM	195.7	217.2	244.7	251.8	242.9
	December Peak	4-9 PM	166.1	183.5	206.6	212.1	204.8
1-in-10	Typical Event Day	1-6 PM	180.8	204.3	233.0	244.2	237.0
	January Peak	4-9 PM	156.1	172.8	202.4	217.8	213.1
	February Peak	4-9 PM	166.8	185.9	216.6	232.0	226.7
	March Peak	4-9 PM	164.4	184.0	213.1	227.1	221.5
	April Peak	1-6 PM	184.1	207.1	238.8	253.3	246.6
	May Peak	1-6 PM	164.2	185.3	213.0	225.4	219.7
	June Peak	1-6 PM	173.0	195.9	224.3	236.3	229.8
	July Peak	1-6 PM	181.1	204.6	233.3	244.6	237.3
	August Peak	1-6 PM	181.8	205.2	233.3	243.6	236.3
	September Peak	1-6 PM	177.5	199.9	226.6	235.4	227.8
	October Peak	1-6 PM	202.7	227.8	257.6	266.6	257.7
	November Peak	4-9 PM	193.2	214.5	241.6	248.8	240.0
	December Peak	4-9 PM	163.2	180.4	203.0	208.3	201.1

12 Although BIP load is assumed to decline by 0.6% per year from 2015 through 2021, there is a small net increase when considering the 1.5% annual load growth from 2011 through 2014. The net increase from 2011 to 2021 is roughly 1% for each day type. Therefore, the increase in aggregate load impacts from 2011 to 2021 is primarily attributed to new enrollment.

Table 5-6 provides the 2011 and 2021 average and aggregate load impact estimates by LCA for a typical event day under 1-in-2 weather conditions. Throughout the forecast period, aggregate load impacts are primarily concentrated in PG&E's Other LCA. In 2011, the Other LCA accounts for 71.4% of aggregate impacts and 68.9% in 2021. Although this LCA accounts for less than 40% 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 2011 and 2021, Other LCA customers provide an average load reduction of roughly 1,700 kW, whereas the average load impact for each of the remaining LCAs does not exceed 550 kW. The Greater Bay Area LCA comprises the second largest share of aggregate load impacts, accounting for slightly over 13% of the total in each year. 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 82% of aggregate impacts in the Other and Greater Bay Area LCAs.

Table 5-6:
2011 and 2021 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
2011	Greater Bay Area	47	795.1	277.9	517.1	24.3	13.3
	Greater Fresno	14	460.6	126.2	334.4	4.6	2.5
	Humboldt	7	555.6	52.7	502.9	3.5	1.9
	Kern	20	591.1	96.8	494.4	9.8	5.4
	Northern Coast	20	465.1	89.8	375.3	7.5	4.1
	Other	77	2,040.5	356.2	1,684.3	129.8	71.4
	Sierra	7	219.9	84.6	135.3	0.9	0.5
	Stockton	7	397.9	202.3	195.7	1.4	0.8
	All Customers	**198**	**1,160.0**	**243.6**	**916.4**	**181.9**	**100.0**
2021	Greater Bay Area	57	836.0	287.5	548.5	31.3	13.1
	Greater Fresno	29	465.8	126.6	339.2	10.0	4.2
	Humboldt	5	551.6	53.5	498.1	2.6	1.1
	Kern	33	610.4	99.5	510.9	16.9	7.1
	Northern Coast	19	482.7	91.8	390.9	7.4	3.1
	Other	95	2,100.3	364.4	1,735.8	164.1	68.9
	Sierra	12	240.1	91.9	148.1	1.7	0.7
	Stockton	18	492.4	247.5	244.9	4.3	1.8
	All Customers	**267**	**1,135.5**	**244.3**	**891.2**	**238.3**	**100.0**

6 SDG&E Load Impact Analysis

This section includes 2010 ex post load impact estimates and 2011-2021 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 2010 BIP Ex Post Load Impact Tables" and "SDG&E 2010 BIP Ex Ante Load Impact Tables."

6.1 Ex Post Load Impact Estimates

On September 27, 2010, SDG&E called its first BIP event since 2007. It was a test event that lasted from 2 PM to 6 PM for BIP option A customers and 3 PM to 6 PM for BIP option B customers. BIP customers dually-enrolled in CPP were not required to respond to the BIP event because there was a CPP event on the same day. Nonetheless, CPP impacts for dually-enrolled BIP customers on that day are presented at the end of this section because they have implications for assumptions used in the ex ante analysis.

Of the 19 customers that were enrolled in BIP at the time of the event, 6 were dually-enrolled in CPP. Therefore, 13 SDG&E customers responded to the BIP event on September 27th. One customer was in BIP option B and the remaining 12 were enrolled in BIP option A. For all option A customers, this day was their first BIP event because they enrolled in the program after 2007.

Figures 6-1 and 6-2 show the average load impact per customer and aggregate impacts in each hour on September 27th. As seen in Figure 6-1, the average load drop over the three-hour event period common to all participants was 32.2 kW. Figure 6-2 shows that the aggregate load drop from 3 PM to 6 PM was 0.42 MW. This represents roughly a 17% reduction relative to the reference load of 2.5 MW. The three-hour event period load of 2.08 MW was substantially higher than the aggregate FSL of 0.08 MW. BIP customers significantly under performed during this event, providing only 17.4% of the 2.42 MW reduction that BIP customers needed in order to be in compliance.

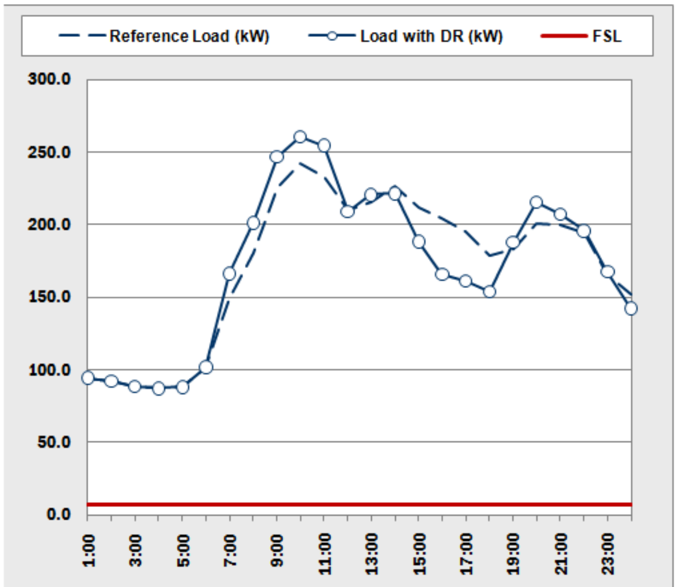
Figure 6-1:
Average Ex Post Load Impact (kW) per Participant for SDG&E BIP Event (September 27, 2010)

TABLE 1: Menu options

Type of Results	Average Enrolled Account
Event	Monday, September 27, 2010
Customer Characteristic	All Customers

TABLE 2: Output

Number of Accounts	13
Average FSL (kW)	6.5



Note: 3 to 6 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	94.3	94.3	0.0	70.4	-14.7	-6.0	0.0	6.0	14.7
2:00	92.1	92.1	0.0	69.4	-14.7	-6.0	0.0	6.0	14.7
3:00	88.6	88.6	0.0	70.3	-14.7	-6.0	0.0	6.0	14.7
4:00	87.0	87.0	0.0	71.3	-14.7	-6.0	0.0	6.0	14.7
5:00	88.0	88.0	0.0	69.4	-14.7	-6.0	0.0	6.0	14.7
6:00	101.7	101.7	0.0	73.3	-14.7	-6.0	0.0	6.0	14.7
7:00	149.3	166.1	-16.8	73.9	-31.5	-22.8	-16.8	-10.8	-2.0
8:00	180.6	201.2	-20.6	81.9	-35.3	-26.6	-20.6	-14.6	-5.9
9:00	225.3	246.7	-21.4	89.9	-36.2	-27.5	-21.4	-15.4	-6.7
10:00	242.3	260.2	-17.8	91.8	-32.6	-23.9	-17.8	-11.8	-3.1
11:00	232.5	254.4	-21.9	96.9	-36.7	-27.9	-21.9	-15.9	-7.2
12:00	210.2	208.6	1.6	90.4	-13.1	-4.4	1.6	7.7	16.4
13:00	215.5	220.5	-5.0	92.4	-19.7	-11.0	-5.0	1.0	9.7
14:00	226.3	221.4	4.9	89.5	-9.8	-1.1	4.9	10.9	19.7
15:00	211.8	188.2	23.6	89.6	8.9	17.6	23.6	29.7	38.4
16:00	204.4	165.8	38.6	89.3	23.9	32.6	38.6	44.6	53.4
17:00	194.7	161.1	33.6	90.1	18.8	27.5	33.6	39.6	48.3
18:00	178.2	153.8	24.5	86.8	9.7	18.4	24.5	30.5	39.2
19:00	182.9	188.0	-5.1	82.5	-19.8	-11.1	-5.1	0.9	9.6
20:00	200.2	215.0	-14.8	80.6	-29.5	-20.8	-14.8	-8.8	0.0
21:00	199.6	206.9	-7.3	81.3	-22.1	-13.4	-7.3	-1.3	7.4
22:00	193.9	195.6	-1.6	78.7	-16.4	-7.7	-1.6	4.4	13.1
23:00	165.7	167.3	-1.5	76.8	-16.3	-7.6	-1.5	4.5	13.2
0:00	151.8	142.1	9.7	77.2	-5.1	3.6	9.7	15.7	24.4
	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	4,117.0	4,114.5	2.6	284.8	-69.7	-27.0	2.6	32.1	74.8

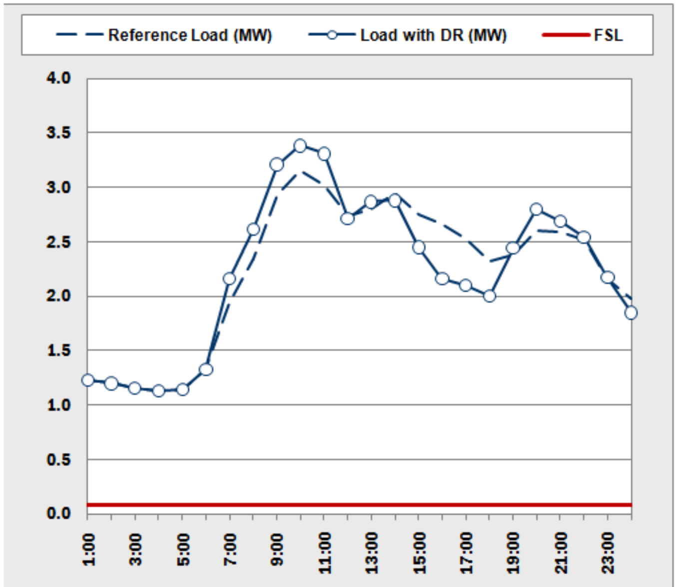
Figure 6-2:
Aggregate Load Impact (MW) for SDG&E BIP Event (September 27, 2010)

TABLE 1: Menu options

Type of Results	Aggregate
Event	Monday, September 27, 2010
Customer Characteristic	All Customers

TABLE 2: Output

Number of Accounts	13
Aggregate FSL (MW)	0.08



Note: 3 to 6 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	1.23	1.23	0.00	70.4	-0.19	-0.08	0.00	0.08	0.19
2:00	1.20	1.20	0.00	69.4	-0.19	-0.08	0.00	0.08	0.19
3:00	1.15	1.15	0.00	70.3	-0.19	-0.08	0.00	0.08	0.19
4:00	1.13	1.13	0.00	71.3	-0.19	-0.08	0.00	0.08	0.19
5:00	1.14	1.14	0.00	69.4	-0.19	-0.08	0.00	0.08	0.19
6:00	1.32	1.32	0.00	73.3	-0.19	-0.08	0.00	0.08	0.19
7:00	1.94	2.16	-0.22	73.9	-0.41	-0.30	-0.22	-0.14	-0.03
8:00	2.35	2.62	-0.27	81.9	-0.46	-0.35	-0.27	-0.19	-0.08
9:00	2.93	3.21	-0.28	89.9	-0.47	-0.36	-0.28	-0.20	-0.09
10:00	3.15	3.38	-0.23	91.8	-0.42	-0.31	-0.23	-0.15	-0.04
11:00	3.02	3.31	-0.28	96.9	-0.48	-0.36	-0.28	-0.21	-0.09
12:00	2.73	2.71	0.02	90.4	-0.17	-0.06	0.02	0.10	0.21
13:00	2.80	2.87	-0.07	92.4	-0.26	-0.14	-0.07	0.01	0.13
14:00	2.94	2.88	0.06	89.5	-0.13	-0.01	0.06	0.14	0.26
15:00	2.75	2.45	0.31	89.6	0.12	0.23	0.31	0.39	0.50
16:00	2.66	2.16	0.50	89.3	0.31	0.42	0.50	0.58	0.69
17:00	2.53	2.09	0.44	90.1	0.24	0.36	0.44	0.51	0.63
18:00	2.32	2.00	0.32	86.8	0.13	0.24	0.32	0.40	0.51
19:00	2.38	2.44	-0.07	82.5	-0.26	-0.14	-0.07	0.01	0.13
20:00	2.60	2.80	-0.19	80.6	-0.38	-0.27	-0.19	-0.11	0.00
21:00	2.59	2.69	-0.10	81.3	-0.29	-0.17	-0.10	-0.02	0.10
22:00	2.52	2.54	-0.02	78.7	-0.21	-0.10	-0.02	0.06	0.17
23:00	2.15	2.17	-0.02	76.8	-0.21	-0.10	-0.02	0.06	0.17
0:00	1.97	1.85	0.13	77.2	-0.07	0.05	0.13	0.20	0.32

	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	53.52	53.49	0.03	284.8	-0.91	-0.35	0.03	0.42	0.97

Table 6-1 shows the average load impact per customer in the offices, hotels, finance & services segment and for all customers. Table 6-2 shows the aggregate impacts. Offices, hotels, finance & services was the only industry segment that had more than three participants in the BIP event. Customers in this segment underperformed substantially during the event. In fact, all offices, hotels, finance & services customers were penalized for failing to comply during the event. Performance and the percent load reduction are higher for all customers because a participant from another industry group complied and curtailed more than half of its load. This customer was the only participant that had experienced a BIP event in the past, which may explain the better performance.

Table 6-1:
Average Customer Load Impact for September 27, 2010 SDG&E Event

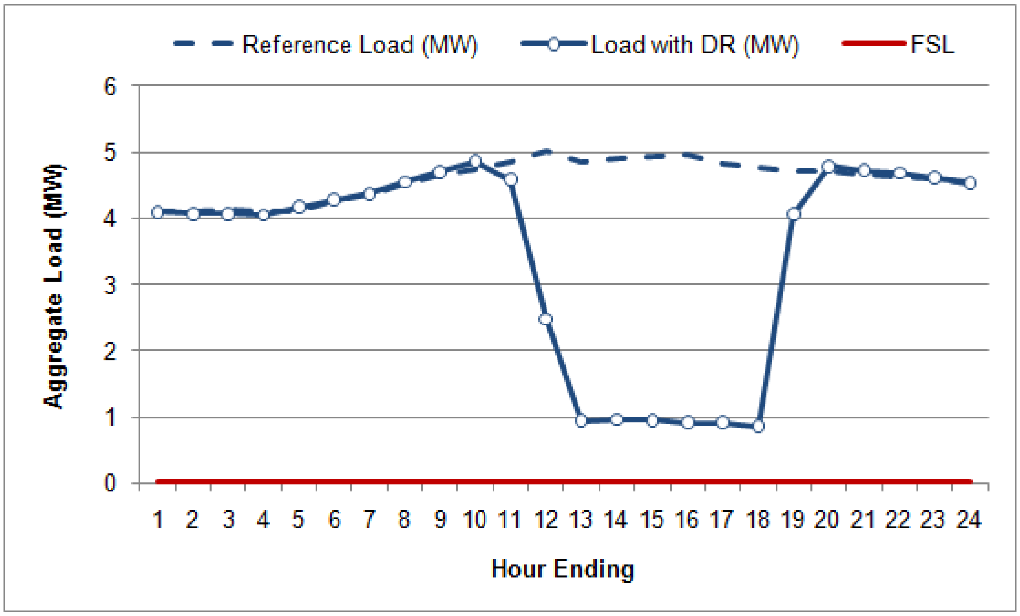
Customer Group	Number of Customers	Reference Load (kW)	Load with DR (kW)	Load Reduction (kW)	Average FSL (kW)	Performance (%)
Offices, Hotels, Finance & Services	6	233.8	208.2	25.6	2.3	11.1
All Customers	13	194.8	163.4	31.4	6.5	16.7

Table 6-2:
Aggregate Load Impact for September 27, 2010 SDG&E Event

Customer Group	Number of Customers	Reference Load (MW)	Load with DR (MW)	Load Reduction (MW)	% Load Reduction
Offices, Hotels, Finance & Services	6	1.40	1.25	0.15	11.0
All Customers	13	2.53	2.12	0.41	16.1

As discussed above, the six BIP customers dually-enrolled in CPP were not required to respond to the BIP event because there was a CPP event on the same day. Although these customers were responding to a CPP event with a much weaker price signal and a longer event window (11 AM to 6 PM), their absolute and percentage load reduction was substantial. As shown in Figure 6-3, aggregate load for these six customers on September 27th dropped from around 5 MW to 1 MW in response to the CPP event. If these customers showed similar behavior during the BIP event, their performance would have been around 80%, which is significantly better than the compliance rate of BIP customers that are not dually-enrolled. Considering that the price signal for BIP is stronger and the event period shorter, it is not unrealistic to assume that dually-enrolled customers would have fully complied and dropped load to their FSL for the BIP event. Given that this day is the only empirical evidence on how these customers perform on a BIP event day, it is assumed that dually-enrolled customers fully comply to their FSL in the ex ante analysis.

Figure 6-3:
Aggregate Load (MW) for BIP Customers Dually-Enrolled in CPP
SDG&E CPP Event (September 27, 2010)



6.2 Ex Ante Load Impact Estimates

SDG&E plans to increase enrollment in its BIP program over the next few years. In May 2011, SDG&E BIP enrollment is expected to equal 26 participants and 55 in May 2014.[13] Afterwards, enrollment is assumed to remain constant until the end of the ex ante forecast period (2021). For ex ante purposes, the estimated reference load of new participants is assumed to be the same as existing SDG&E BIP customers. As for future performance relative to the reference load and FSL, the following assumptions are used in the ex ante analysis:

- Performance for customers that are not dually-enrolled in CPP is the same as their performance in the 2010 event: 16.7%. This event performance is the only empirical evidence that is available for these customers;
- Performance for customers that are dually-enrolled in CPP: 100%. Considering that these customers dropped 80% of their load in response to the September 27th CPP event, it is expected that they would be able to provide 100% performance in response to a BIP event that has a much stronger price signal; and
- Performance for new enrollees: 71.7%. This performance level is the average of the above two segments weighted by aggregate load.

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 2014. Impacts are reported for 2014 because it is the year in which enrollment growth reaches a steady state. For a 1-in-2 typical event day, the estimated load impact for the average participant is 288.2 kW from 1 PM to 6 PM.

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13 The May enrollment number for each year is assumed to be constant from May through October.

This represents a 70.9% impact relative to the average reference load of 406.3 kW. Based on 1-in-10 year weather conditions, the load impact pattern over the event period is very similar to that in a 1-in-2 weather year because BIP customer usage is not sensitive to temperature. The average load impact across the event period is 290.5 kW, which is less than 1% higher than in the 1-in-2 weather year.

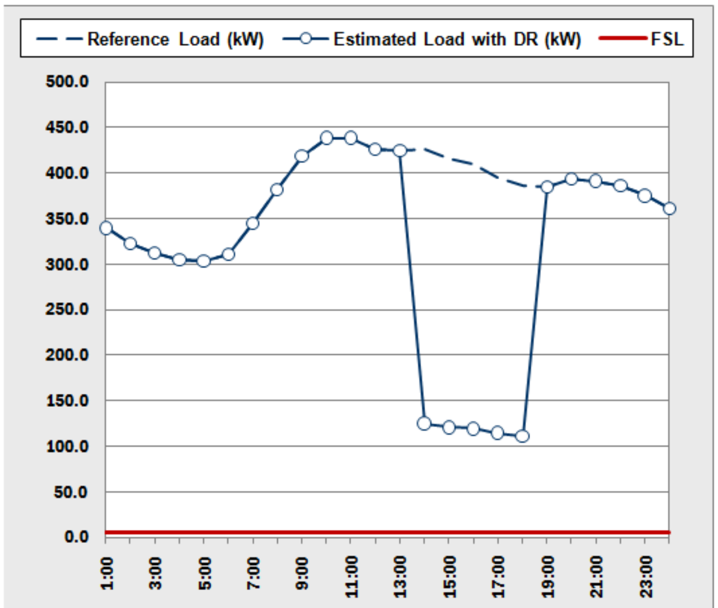
Figure 6-4:
SDG&E BIP Average Load Impact (kW) per Customer in 2014
for a Typical Event Day Based on 1-in-2 Year Weather Conditions

TABLE 1: Menu options

Type of Results	Average Enrolled Account
Weather Year	1-in-2
Forecast Year	2014
Day Type	Typical Event Day
Customer Characteristic	All Customers

TABLE 2: Output

Number of Accounts	55
Average FSL (kW)	4.9
Proxy Date	N/A
Average Load Impact (kW) (1-6pm)	288.2
% Load Impact (1-6pm)	70.9%



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	339.5	339.5	0.0	70.5	-14.1	-5.8	0.0	5.8	14.1
2:00	322.4	322.4	0.0	69.9	-14.1	-5.8	0.0	5.8	14.1
3:00	311.9	311.9	0.0	69.4	-14.1	-5.8	0.0	5.8	14.1
4:00	305.1	305.1	0.0	68.7	-14.0	-5.7	0.0	5.7	14.0
5:00	303.4	303.4	0.0	68.9	-14.0	-5.7	0.0	5.7	14.0
6:00	310.2	310.2	0.0	68.9	-14.0	-5.7	0.0	5.7	14.0
7:00	344.3	344.3	0.0	69.2	-14.1	-5.8	0.0	5.8	14.1
8:00	381.3	381.3	0.0	71.3	-14.1	-5.8	0.0	5.8	14.1
9:00	419.0	419.0	0.0	75.1	-14.1	-5.8	0.0	5.8	14.1
10:00	438.6	438.6	0.0	78.7	-14.1	-5.8	0.0	5.8	14.1
11:00	438.4	438.4	0.0	81.9	-14.1	-5.8	0.0	5.8	14.1
12:00	426.1	426.1	0.0	82.1	-14.2	-5.8	0.0	5.8	14.2
13:00	425.0	425.0	0.0	82.1	-14.1	-5.8	0.0	5.8	14.1
14:00	425.4	124.9	300.5	81.6	286.4	294.7	300.5	306.3	314.6
15:00	416.0	120.7	295.3	81.4	281.3	289.6	295.3	301.1	309.4
16:00	410.1	119.1	291.0	81.0	276.9	285.2	291.0	296.8	305.1
17:00	394.6	114.6	280.0	80.0	265.9	274.2	280.0	285.8	294.1
18:00	385.5	111.4	274.1	78.0	260.0	268.3	274.1	279.9	288.2
19:00	385.1	385.1	0.0	76.0	-14.0	-5.7	0.0	5.7	14.0
20:00	393.8	393.8	0.0	74.0	-14.1	-5.8	0.0	5.8	14.1
21:00	391.0	391.0	0.0	72.5	-14.1	-5.8	0.0	5.8	14.1
22:00	386.3	386.3	0.0	72.1	-14.1	-5.8	0.0	5.8	14.1
23:00	375.2	375.2	0.0	71.6	-14.0	-5.7	0.0	5.7	14.0
0:00	361.2	361.2	0.0	70.6	-14.1	-5.8	0.0	5.8	14.1

	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	9,089.2	7,648.3	1,441.0	116.2	1371.9	1412.7	1441.0	1469.2	1510.0

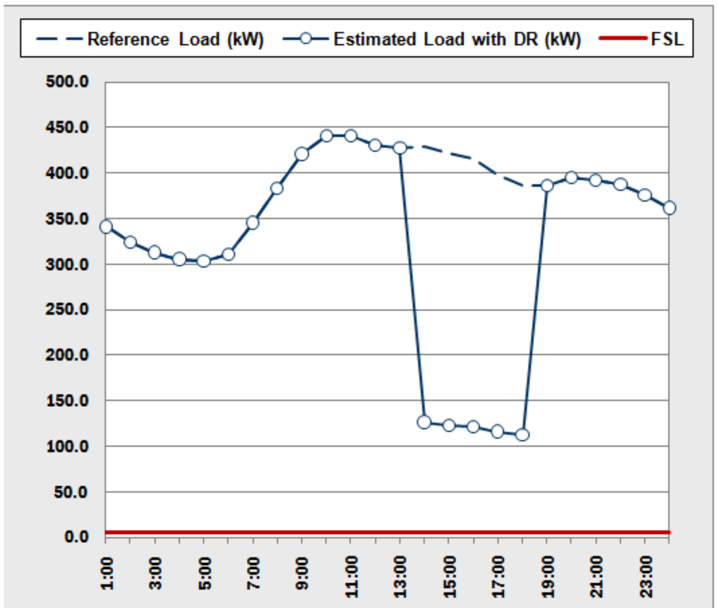
Figure 6-5:
SDG&E BIP Average Load Impact (kW) per Customer in 2014
for a Typical Event Day Based on 1-in-10 Year Weather Conditions

TABLE 1: Menu options

Type of Results	Average Enrolled Account
Weather Year	1-in-10
Forecast Year	2014
Day Type	Typical Event Day
Customer Characteristic	All Customers

TABLE 2: Output

Number of Accounts	55
Average FSL (kW)	4.9
Proxy Date	N/A
Average Load Impact (kW) (1-6pm)	290.5
% Load Impact (1-6pm)	70.8%



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	341.0	341.0	0.0	73.3	-14.1	-5.8	0.0	5.8	14.1
2:00	323.7	323.7	0.0	72.5	-14.1	-5.8	0.0	5.8	14.1
3:00	312.8	312.8	0.0	72.2	-14.1	-5.8	0.0	5.8	14.1
4:00	305.4	305.4	0.0	71.5	-14.1	-5.8	0.0	5.8	14.1
5:00	303.1	303.1	0.0	71.4	-14.1	-5.8	0.0	5.8	14.1
6:00	310.6	310.6	0.0	71.2	-14.1	-5.8	0.0	5.8	14.1
7:00	345.2	345.2	0.0	71.9	-14.2	-5.8	0.0	5.8	14.2
8:00	383.6	383.6	0.0	74.6	-14.2	-5.8	0.0	5.8	14.2
9:00	420.9	420.9	0.0	77.8	-14.2	-5.8	0.0	5.8	14.2
10:00	441.0	441.0	0.0	80.9	-14.2	-5.8	0.0	5.8	14.2
11:00	441.1	441.1	0.0	83.0	-14.1	-5.8	0.0	5.8	14.1
12:00	430.1	430.1	0.0	84.4	-14.9	-6.1	0.0	6.1	14.9
13:00	427.1	427.1	0.0	84.0	-14.5	-6.0	0.0	6.0	14.5
14:00	429.2	126.4	302.8	84.3	288.5	297.0	302.8	308.7	317.2
15:00	420.9	122.5	298.5	84.8	284.2	292.6	298.5	304.3	312.7
16:00	415.4	121.0	294.4	84.3	280.2	288.6	294.4	300.3	308.7
17:00	398.0	116.0	282.0	82.6	267.6	276.1	282.0	287.8	296.4
18:00	386.8	112.0	274.8	81.0	260.4	268.9	274.8	280.7	289.3
19:00	386.5	386.5	0.0	78.5	-14.1	-5.8	0.0	5.8	14.1
20:00	394.7	394.7	0.0	75.8	-14.2	-5.8	0.0	5.8	14.2
21:00	392.4	392.4	0.0	74.9	-14.2	-5.8	0.0	5.8	14.2
22:00	387.3	387.3	0.0	74.3	-14.1	-5.8	0.0	5.8	14.1
23:00	375.4	375.4	0.0	73.6	-14.1	-5.8	0.0	5.8	14.1
0:00	361.6	361.6	0.0	73.0	-14.1	-5.8	0.0	5.8	14.1

	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	9,133.9	7,681.4	1,452.5	173.0	1382.8	1424.0	1452.5	1481.0	1522.2

Table 6-3 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 2021 time period, 1-in-2 and 1-in-10 aggregate load impacts vary from 12.4 MW to 13.4 MW in November through March and 14.6 MW to 16.2 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 16.2 MW, which occurs during the September 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 7.3 MW in 2011 to nearly 16 MW during 2015 to 2021.

Table 6-3:
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	2011	2012	2013	2014	2015-2021
1-in-2	Typical Event Day	1-6 PM	7.3	10.5	12.9	15.9	15.9
	January Peak	4-9 PM	5.1	7.3	9.8	12.0	13.4
	February Peak	4-9 PM	5.4	7.6	9.8	12.0	13.0
	March Peak	4-9 PM	5.6	8.0	10.1	12.3	13.0
	April Peak	1-6 PM	6.5	9.3	11.6	14.2	14.6
	May Peak	1-6 PM	6.9	9.9	12.1	14.9	14.9
	June Peak	1-6 PM	7.1	10.2	12.4	15.3	15.3
	July Peak	1-6 PM	7.3	10.6	13.0	15.9	15.9
	August Peak	1-6 PM	7.2	10.4	12.8	15.7	15.7
	September Peak	1-6 PM	7.3	10.5	12.8	15.7	15.7
	October Peak	1-6 PM	6.6	9.7	11.9	14.7	14.7
	November Peak	4-9 PM	6.3	8.8	10.8	12.8	12.8
	December Peak	4-9 PM	6.5	8.8	10.8	12.4	12.4
1-in-10	Typical Event Day	1-6 PM	7.4	10.6	13.0	16.0	16.0
	January Peak	4-9 PM	5.1	7.1	9.5	11.6	13.0
	February Peak	4-9 PM	5.4	7.6	9.8	12.0	13.1
	March Peak	4-9 PM	5.8	8.2	10.4	12.7	13.4
	April Peak	1-6 PM	6.7	9.6	12.0	14.7	15.1
	May Peak	1-6 PM	7.0	10.2	12.4	15.3	15.3
	June Peak	1-6 PM	7.1	10.2	12.4	15.2	15.2
	July Peak	1-6 PM	7.4	10.7	13.1	16.0	16.0
	August Peak	1-6 PM	7.4	10.6	13.0	16.0	16.0
	September Peak	1-6 PM	7.4	10.8	13.2	16.2	16.2
	October Peak	1-6 PM	6.6	9.7	12.0	14.8	14.8
	November Peak	4-9 PM	6.2	8.7	10.6	12.6	12.6
	December Peak	4-9 PM	6.6	8.9	10.9	12.5	12.5

7 Recommendations for All Utilities

The PG&E and SDG&E test events in 2010 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 test event each year.

When calling a test event, all utilities need to consider the event conditions that they are attempting to simulate. The 2009 test events for PG&E and SDG&E simulated different event conditions. SDG&E did not provide advanced notification of the test event, whereas PG&E provided 48-hour advanced notification. Although the notification lead time for BIP is much shorter than 48 hours, the PG&E test event simulated a situation when there are generation supply shortages during a long heat wave and customers expect a BIP event. The SDG&E test event simulated a situation when 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. If a BIP test event is meant to simulate a transmission or distribution outage, no advanced notice should be given.

Appendix A. 2009 TA&TI and Auto-DR Analysis

Technical Assistance & Technology Incentives (TA&TI) and Auto Demand Response (Auto-DR) are separate programs that facilitate demand reductions for customers that would like to enroll in a DR program or customers that are already enrolled in a DR program. For the 2010 BIP evaluation, there is no TA&TI or Auto-DR analysis because SCE did not call an event in 2010. PG&E and SDG&E called an event in 2010, but these utilities do not offer TA&TI or Auto-DR assistance for BIP customers. In the 2009 evaluation, the impact was analyzed for customers that received TA&TI and Auto-DR assistance between the 2006 and 2009 SCE BIP events. The results were inconclusive due to a lack of statistical power. This appendix provides the TA&TI and Auto-DR analysis section from the 2009 BIP report.

For the analysis of the impact of TA&TI and Auto-DR on event performance, customers that participated in both the 2006 and 2009 SCE BIP events are included. The September 23, 2009 event had 650 participants and lasted for roughly 2 hours, from 2:16 PM to 4:05 PM. The July 24, 2006 event had 555 participants and lasted for roughly 3 hours, from 3:32 PM to 5:37 PM. There are 400 customers for which we have data that participated in both events. All 400 customers are included in the analysis because the impact of TA&TI and Auto-DR is determined by comparing customers that received assistance between the two events to those that did not.

As of September 2009, 66 SCE BIP accounts received technical audits, of which 34 were completed between the 2006 and 2009 SCE BIP events. As for incentives, 8 SCE BIP accounts received TA&TI incentives and 5 received Auto DR incentives, of which 11 received these incentives between the 2006 and 2009 SCE BIP events. TA&TI incentives ranged from $41,000 to $853,000 and averaged $225,000. Auto-DR incentives ranged from $29,000 to $885,000 and averaged $349,000. Considering that so few BIP customers received TA&TI and Auto-DR incentives, it is difficult to make a robust comparison to customers that did not receive incentives. Only 11 out of 400 (2.75%) customers in the analysis received assistance between the 2 events.

Table A-1 shows the results of the analysis of the impact of TA&TI and Auto-DR on under performance during BIP events. The dependent variable in this regression is the change in under performance from the 2006 SCE BIP event to the 2009 SCE BIP event. For example, if a customer under performed by 100 kW per hour during the 2006 event and then under performed by 25 kW per hour during the 2009 event, its value for the dependent variable would be negative 75 kW. Therefore, a negative coefficient means that a variable led to a decrease in under performance from one event to the next, which is what we would expect from TA&TI and Auto-DR.

Although substantial incentives were paid to a few customers, the results are inconclusive because of a lack of statistical power. The coefficients for technical audit, technology incentive and Auto-DR incentive are negative as we would expect, but they are insignificant. Similarly, the F-test of the joint significance of the regression as a whole shows that the regression variables are jointly insignificant. It is encouraging that the coefficients are negative for technical audit, technology incentive and Auto-DR incentive, but the results are inconclusive because of a lack of statistical power.

Table A-1:
Regression Output for Analysis of Performance
2006 and 2009 SCE Events
n=400

Variable	Coefficient	T-statistic	P-Value	95% Confidence Interval	
Technical Audit	-68.23	-0.87	0.39	-223.07	86.61
Technology Incentive ($ thousands)	-0.29	-1.51	0.13	-0.66	0.09
AutoDR Incentive ($ thousands)	-0.24	-1.71	0.09	-0.52	0.04
Log of Average kW	77.12	2.04	0.04	2.73	151.51
Peak kW Ratio	83.55	2.25	0.03	10.51	156.58
Manufacturing	-125.06	-1.28	0.20	-316.99	66.86
Wholesale, Transport & Other Utilities	-108.97	-1.13	0.26	-298.13	80.20
Retail Stores	-212.55	-1.30	0.20	-535.01	109.91
Offices, Hotels, Finance, Services	-166.25	-1.67	0.10	-362.26	29.77
Schools	45.24	0.65	0.51	-90.98	181.46
Institutional/Government	-376.46	-2.08	0.04	-733.00	-19.92
Outside LA Basin LCA	-79.95	-0.54	0.59	-368.88	208.99
Ventura LCA	-79.88	-1.59	0.11	-178.68	18.93
Constant	-403.00	-2.03	0.04	-792.62	-13.38

Other than performance during events, participation in TA&TI and Auto-DR may affect FSL selection. Customers that receive incentives may be able to lower their FSL because the new equipment allows them to provide more of a load reduction. This theory cannot be tested as of now because none of the customers that received incentives changed their FSL. Few BIP customers change their FSL and even fewer participate in TA&TI and Auto-DR, so the chance of having both occur for one customer is small. As BIP customers have more chances to change their FSL and enroll in TA&TI and/or Auto-DR in the future, we may be able to test the impact of each program on FSL selection, but as of now, it is not possible.

Appendix B. 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 B-1 provides the underlying hourly predicted and actual kW values that are reflected in Figure 3-1.

**Table B-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	1,072.9	1,080.8	7.9	0.74%	1,141.8	1,116.7	-25.1	-2.20%	321.4	317.1	-4.3	-1.34%
2	1,061.5	1,071.4	9.8	0.93%	1,127.4	1,102.3	-25.1	-2.23%	300.0	295.0	-4.9	-1.65%
3	1,056.5	1,063.8	7.3	0.69%	1,121.5	1,098.7	-22.8	-2.04%	287.1	284.3	-2.8	-0.98%
4	1,065.5	1,072.1	6.6	0.62%	1,120.4	1,097.4	-22.9	-2.04%	279.3	276.5	-2.8	-1.00%
5	1,099.4	1,098.4	-1.0	-0.09%	1,134.2	1,113.4	-20.8	-1.84%	275.9	273.9	-2.0	-0.71%
6	1,137.6	1,136.7	-0.9	-0.08%	1,181.7	1,160.9	-20.8	-1.76%	283.7	282.0	-1.7	-0.62%
7	1,165.9	1,169.4	3.5	0.30%	1,245.6	1,234.6	-10.9	-0.88%	316.2	313.4	-2.8	-0.89%
8	1,192.0	1,193.5	1.5	0.13%	1,264.8	1,255.1	-9.7	-0.77%	362.9	356.0	-6.9	-1.90%
9	1,203.7	1,193.6	-10.1	-0.84%	1,260.5	1,244.0	-16.5	-1.31%	393.6	388.5	-5.1	-1.29%
10	1,208.0	1,191.9	-16.1	-1.33%	1,265.4	1,245.6	-19.7	-1.56%	415.9	408.0	-8.0	-1.91%
11	1,206.3	1,196.5	-9.7	-0.81%	1,256.7	1,237.4	-19.4	-1.54%	418.6	411.9	-6.7	-1.59%
12	1,182.7	1,183.2	0.5	0.04%	1,226.6	1,217.4	-9.2	-0.75%	405.1	401.0	-4.2	-1.03%
13	1,143.9	1,156.5	12.7	1.11%	1,177.5	1,163.2	-14.3	-1.22%	409.3	403.6	-5.7	-1.40%
14	1,132.8	1,142.0	9.2	0.82%	1,175.3	1,160.3	-14.9	-1.27%	410.7	404.0	-6.8	-1.65%
15	1,109.3	1,124.0	14.7	1.33%	1,150.9	1,134.1	-16.8	-1.46%	402.4	395.6	-6.8	-1.69%
16	1,084.8	1,100.2	15.4	1.42%	1,102.7	1,084.4	-18.3	-1.66%	396.3	389.3	-7.0	-1.77%
17	1,067.4	1,079.0	11.6	1.09%	1,095.7	1,081.2	-14.5	-1.32%	379.3	374.9	-4.4	-1.16%
18	1,051.9	1,065.2	13.3	1.27%	1,089.3	1,075.0	-14.4	-1.32%	366.0	362.3	-3.7	-1.02%
19	1,055.0	1,072.8	17.8	1.68%	1,138.7	1,131.3	-7.4	-0.65%	362.1	359.0	-3.1	-0.86%
20	1,070.3	1,086.3	16.1	1.50%	1,169.7	1,161.2	-8.5	-0.73%	369.8	364.1	-5.7	-1.54%
21	1,097.7	1,104.2	6.5	0.59%	1,171.7	1,160.8	-10.9	-0.93%	369.1	363.2	-5.9	-1.60%
22	1,102.2	1,103.4	1.1	0.10%	1,174.2	1,171.6	-2.6	-0.22%	361.2	357.6	-3.6	-0.99%
23	1,098.6	1,092.4	-6.2	-0.56%	1,180.6	1,175.5	-5.1	-0.43%	350.5	348.8	-1.7	-0.48%
24	1,120.4	1,106.6	-13.7	-1.22%	1,168.9	1,164.9	-4.0	-0.34%	338.3	336.0	-2.3	-0.68%
Avg. (1-6 PM)	**1,089.2**	**1,102.1**	**12.9**	**1.18%**	**1,122.8**	**1,107.0**	**-15.8**	**-1.41%**	**391.0**	**385.2**	**-5.7**	**-1.47%**