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A Measurement and Evaluation Study of PY2007 Business Energy Coalition Program and PY2005-07 Special Projects Group Program

FINAL

Submitted to:

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Table of Contents

List of Figures

List of Tables

1

Executive Summary

This report presents the impact evaluation and process assessment results of the 2007 Pacific Gas and Electric Company's Business Energy Coalition Program and the 2005-2007 Special Projects Group Program.

1.1 Program Overview

The Business Energy Coalition (BEC) Program is a third-party run tariff-based pilot demand-response program that was ordered in Decision (D.) 05-01-056, extended in D.06-03-024, and revised in D.06-11-049, D.07-12-048, and CPUC Resolution E-4163. The program began in 2005 as an initiative between PG&E and major San Francisco business and civic leaders to demonstrate the load curtailment capabilities that exist within commercial customers located in the San Francisco region of PG&E's service territory. The idea behind the BEC program was to form a cooperative comprised of PG&E commercial customers (primarily downtown office buildings and hotels) that can collectively commit to reducing their loads by a given amount on event days. This collective load reduction approach provides program participants opportunities to work together and make a significant reduction in energy demand on event days when PG&E's electric supply is strained and the threat of rolling blackouts exist. As with all of PG&E's demand response programs, the BEC program was designed to improve the reliability of electric loads to the customers in its service territory.

For the 2007 program year (PY), the BEC program was available to all PG&E bundled-service, direct access, and wholesale customers in business sectors such as office, hospitality, and information technology. To be enrolled in the program, customers had to have a minimum average monthly demand of 200 kW and been able to reduce their demand by a minimum of 200 kW. Participants also had to take service on a PG&E demand time-of-use rate schedule and have the required interval metering equipment installed and Internet access in place prior to enrolling in the BEC program.

The BEC estimates each customer's committed load reduction by taking the difference between a customer's average peak demand and its firm service level (FSL). Participants are paid based on their committed load reduction. The FSL is designated by each customer with the approval of the BEC as the kW amount it can reduce down to for a given event. The average peak demand for each BEC participant is based on a two-year average peak kW value calculated for each month between and including May through October for the 2007 program year. The average peak demand is then set equal to the maximum of these six monthly two-year average values. An example of this calculation is shown in Figure 1-1 for a hypothetical participant in program year 2007.

Figure 1-1: Methodology for Calculating A Customer's Average Peak Demand

PROJECT: Example Participant
ADDRESS: 1234 Main Street

HISTORIC PEAK KW DEMANDS

				AVERAGE PEAK - kW =		4,077
Year	**May**	**June**	**July**	**August**	**September**	**October**
2005	3,581	3,982	3,897	3,777	3,935	3,892
2004	3,459	3,610	3,725	3,906	4,218	4,047
2003						
2002						
2-Year Avg. =	3,520	3,796	3,811	3,842	4,077	3,970

At the same time the BEC program originated, PG&E contracted with The Energy Coalition to lead a Special Projects Group (SPG) whose primary purpose is to develop the San Francisco Integrated Demand-Side Management (IDSM) Alliance. The SPG was designed by the former executive director of The Energy Coalition, John Phillips, to produce a broad range of IDSM services within the City and County of San Francisco. Activities of the SPG included:

- the development of specific-sets of IDSM services with the goal of implementing programs that are at least as cost-effective as PG&E's current demand-side management portfolio for its business and residential customers, and
- the creation of a new "outside the box" IDSM model to help make demand-side management a sustainable and profitable way to enhance electric capacity.

As part of its work, the SPG was to provide two report deliverables[1] to describe the best means for integrating energy efficiency and demand-response programs into an IDSM alliance and to define the evolution of an IDSM alliance between PG&E, local governments, including but not limited to the City and County of San Francisco.

[1] As of August 2008, one of the two SPG report deliverables has been completed.

1.2 Evaluation Objectives

The following are the principal objectives of this evaluation.

- Conduct process evaluations of the 2007 BEC and 2005-2007 SPG programs, report findings, and make recommendations to enhance the operation of these programs.
- Using 2007 load data supplied by PG&E, develop estimates of the BEC program peak period impacts by reporting estimated load reduction for each event and for the 2007 program year.
- Compare alternative load reduction impacts estimated for the 2007 BEC program.

1.3 Process Assessment Results

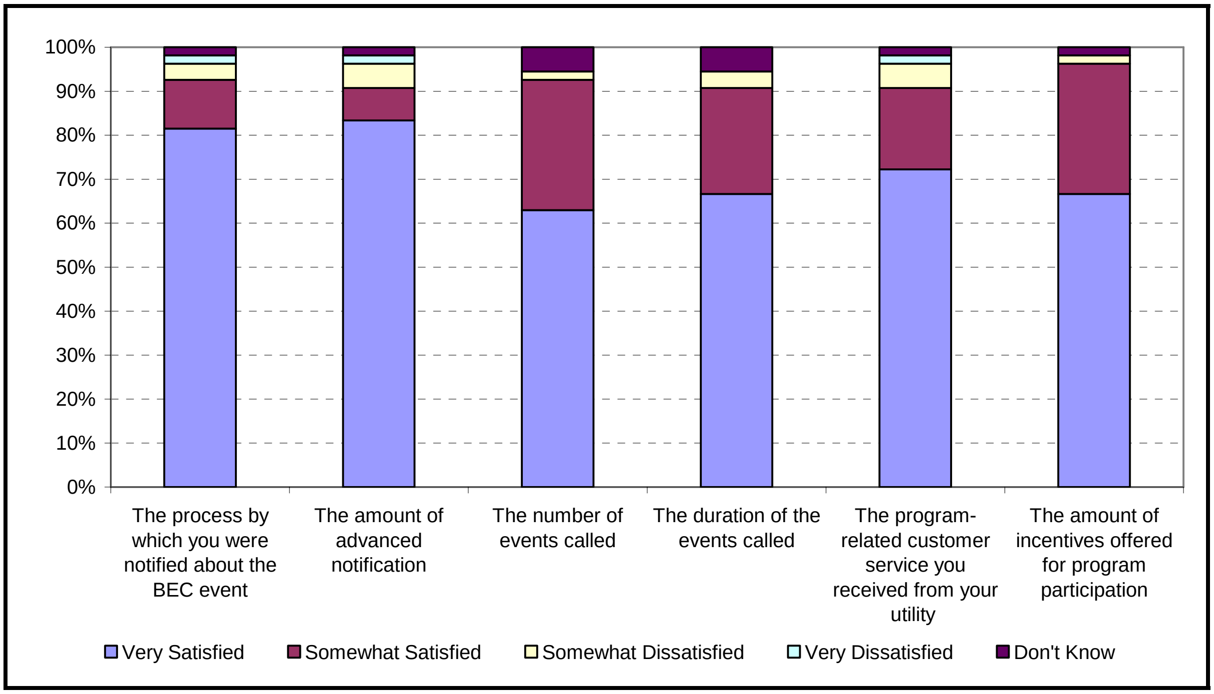
The 2007 BEC program process assessment portion of the evaluation focused on the following areas:

- Participants' self-reported satisfaction with the BEC program,
- Program marketing and enrollment,
- Demand-response barriers faced by customers within BEC's target market and the impact they have had on BEC's program design and theory,
- Guidance that BEC participants receive on demand-response load reduction actions and estimates of curtailable load,
- Participant characteristics,
- Participation in 2007 events, and
- A brief summary of the original purpose, recent deliverables, and actions resulting from the SPG.

1.3.1 Satisfaction with the BEC Program

During the participant phone surveys conducted as a part of the 2007 BEC evaluation, customers were asked a battery of questions to determine their satisfaction level with the BEC program overall, as well as various program elements. Overall self-reported satisfaction was very high with 98% of those interviewed reporting they were "very" or "somewhat" satisfied with the program. As Figure 1-2 shows, participants reported very high levels of satisfaction with all aspects of the BEC program. Using the percentage of respondents indicating they were "very" or "somewhat" satisfied as an indication of satisfaction, all program elements had more than 90% of participants reporting satisfaction. The highest level of satisfaction reported was for the incentives offered, followed by the event notification process and the number of events called. Participant satisfaction can also be judged by the fact that all 54 participants surveyed reported that they planned to continue their participation in the BEC program for the summer of 2008.

Figure 1-2: Satisfaction with Program Elements



BEC participants also seemed to be very satisfied with the assistance they received from PG&E and the BEC to help them identify load reduction options. Ninety-seven percent of those surveyed reported this assistance was somewhat or extremely helpful and 80% said their organization received as much support as they needed to develop their load reduction strategies.

1.3.2 Program Marketing and Enrollment

Interviews with BEC personnel were a key component of the BEC process evaluation. These interviews found that the BEC marketing and enrollment process during PY2007 continued to bring in PG&E customers that were otherwise not participating in demand-response programs or had previously rejected participation in DR programs ("hard-to-reach"). BEC staff members worked well with the PG&E account representatives to identify hard-to-reach customers and educate them about the program.

The program managers interviewed expressed mild frustration with one aspect of the enrollment process, which requires new BEC participants to be placed in PG&E's metering queue (since very often changes to the meter are necessary). The wait can be months long due to the number of other programs also requiring metering work.

1.3.3 Demand-Response Barriers Faced by Customers within BEC's Target Market and the Impact They Have Had on BEC's Program Design and Theory

The BEC staff identified six primary barriers thought to keep customers within BEC's target market from participating in demand-response programs:

- Overall risk aversion,
- Perceived inability to reduce load during peak hours,
- Lack of demand-response enabling technology,
- Lack of expertise in curtailment actions,
- Restrictions imposed on buildings due to lease agreements, and
- Complicated program requirements.

To help customers overcome these barriers, the BEC program was designed with the following elements:

- Detailed site assessments to educate building personnel on specific demand-response actions that can be taken for a specific location and the load reductions associated with these actions,
- Simplified program requirements (such as a consistent load reduction goal and a straightforward incentive structure) that allow for ease of participation,
- A gateway device installed in all locations that enables customers to view their load reductions in real time and adjust their curtailment actions as needed, and
- Education for both building engineers and tenants to help them understand the benefits of demand response and the actions that can be taken by all parties to help reduce the overall load.

1.3.4 Guidance BEC Participants Receive on DR Load Reduction Actions and Estimates of Curtailable Load

All customers who enroll in the BEC program receive an extensive site assessment from ASW Engineering to help them develop load reduction protocols they can use to participate in BEC events while minimizing the impact on their buildings' operations. These audits also help participants understand the expected energy savings resulting from each load reduction protocol. Program staff report that participants who have received a BEC site assessment take different actions on BEC event days than those who have not received an audit.

The feedback received during the BEC telephone surveys indicates that the assistance provided to BEC participants upon enrolling is very effective. Approximately three-fourths of those surveyed indicated they had received an on-site technical assessment that assisted them in developing a curtailment plan for BEC events and setting their FSL. Nearly all of those who received this on-site assessment characterized it as somewhat or extremely helpful. Ninety-eight percent of those who received the audit reported taking all or some of the actions prescribed by the audit during a curtailment event. Overall, 80% of those surveyed reported their organization received as much support as needed in the development of load reduction strategies.

1.3.5 Participant Characteristics

The telephone surveys conducted with BEC participants provided some key demographic information on customers enrolled in the BEC program.

- Commercial businesses comprise the majority of customers enrolled in the BEC program, followed by hotel/hospitality businesses.
- HVAC was the largest end use (kWh) reported by BEC participants (53%), followed by lighting (17%).
- More than half of BEC participants reported that energy costs accounted for 10% or less of their organization's total annual operating costs.
- Nearly a quarter of BEC participants reported previous participation in another PG&E demand-response program.
  - Fifty percent recall being recruited by PG&E for another demand-response program and 70% of those acknowledged signing up for the program (most frequently for DBP).
  - Two-thirds of those who had enrolled in another demand-response program stated they had actively dropped load for at least one of the demand-response events.
- The most significant reason participants gave for enrolling in the BEC program was "being a good corporate citizen" (nearly 75% of those surveyed reported it was "extremely significant"). This leads one to believe that BEC is attracting customers who are a good fit for a cooperative program such as BEC.

1.3.6 Participation in 2007 BEC Events

All participants surveyed who had received notification about one or more events reported that they felt the notification process was effective, with 92% reporting it was "very effective." The four events in 2007 were all "day-ahead" events meaning participants were contacted and told of the event the day prior to the event and thus received approximately 24 hours to prepare themselves for the curtailment event that was about to occur. Participants were asked about the minimum amount of time they would need to respond to an event and nearly half reported they would need more than two hours, which signifies that a large portion of enrolled customers would be unable to respond fully in the event that a "day-of" event was called (which has a program minimum of one hour notice).

Eighty-seven percent of BEC participants reported participating in all of the 2007 BEC events. Reasons for not participating included "operation was already was shut down," "did not receive event notification," "could not respond in time," and "could not reduce load on that particular day." The primary curtailment actions taken during an event were reducing overhead lighting and turning off non-critical equipment (both reported by 68% of those surveyed). Allowing the temperature to rise in tenant-occupied space was reported by approximately one-third of those surveyed. Most of these actions were controlled manually (49%), followed by partially automated (47%). Only 4% were fully automated. Thirteen percent reported that they increased their energy use prior to the curtailment events to make up for the load reduction that was to occur and 7% reported doing so after the event had ended. On average, BEC participants estimated that their curtailment actions resulted in a 10% reduction in their overall load.

The majority of BEC participants (85%) reported feeling that their organization was very well prepared to manage the demand reductions called for by the BEC program during the summer of 2007.

1.3.7 A Summary of the Original Purpose, Recent Deliverables, and Actions Resulting from the SPG

The Special Project Group (SPG) was established to explore ways in which PG&E can increase the overall efficiency and reliability of its power system, specifically through the development of a San Francisco integrated demand side management (IDSM) Alliance. PG&E and The Energy Coalition developed the SPG through a Scope of Work which states that through its principal, John Phillips, the Energy Coalition shall facilitate the development of an IDSM alliance between PG&E and the city of San Francisco to "deliver specific sets of IDSM services with a goal of implementing programs that are at least as cost-effective as PG&E's portfolio which is designed for and delivered to business and residential customers of the City."[2]

Itron carried out two specific activities to evaluate the Special Projects Group (SPG). The team first reviewed the scope of work[3] between PG&E and The Energy Coalition that describes the purpose of the SPG and then it critically examined the recommendations and findings made by the SPG in its first report deliverable. The SPG was contracted by PG&E to produce two reports. The first of these reports was completed in March 2008 and the second has yet to be released.[4]

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[2] From Exhibit A of PG&E Service Contract #4600017251 between PG&E and the Business Energy Coalition.

[3] Exhibit A of PG&E Service Contract #4600017251 between PG&E and the Business Energy Coalition.

[4] The second report was scheduled to be issued in the spring of 2008; however, as of the writing of this report in August 2008, it has not been issued.

In addition to the scope of work and the SPG deliverables, Itron had planned to conduct a key actor interview with John Phillips, former executive director of The Energy Coalition and primary member of the SPG. As mentioned earlier, the interview did not take place due to circumstances outside Itron's control. Based on a recommendation of Mark Cristofani of PG&E, Itron contacted Mark Fleming as a potential interviewee. However, Mr. Fleming felt that he did not have the detailed background information needed regarding the development of the SPG to provide us with enough information to support this process evaluation.

Since the second report deliverable has yet to be complete and Itron's interview with a member of the SPG never took place, the process evaluation of the Special Projects Group is limited to an examination of the SPG's objectives as they were stated in the relevant scope of work between PG&E and The Energy Coalition and an evaluation of whether or not the SPG's findings and recommendations from the first report serve to advance PG&E's development of an Integrated Demand-Side Management (ISDM) Alliance.

The first SPG report deliverable presents a **transformation process model** that will "revolutionize" the way in which PG&E reaches out to its customers regarding the importance of conserving energy. The message of this outreach effort is to make demand response and energy efficiency a number one priority in order to help secure PG&E's energy reserves. This model attempts to converge top-down and bottom-up strategies on improving the value of new outreach programs to energy customers and PG&E shareholders, hopefully resulting in prioritizing demand response and energy efficiency.

After a review of the objectives outlined in Exhibit A of PG&E's contract with the BEC and a reading of the first report deliverable, Itron finds that the SPG has taken initial steps to outline a process to transform PG&E's IDSM Alliance, but has yet to provide details on how to make this transformation occur. The theme of the first report is that there is a need for change regarding energy use and the time for this change is immediate, however there are few actionable steps laid out. This may be because the SPG plans to present the evolution of this IDSM Alliance in its second SPG report deliverable, however a draft hasn't been issued to date. Itron therefore cannot make any conclusions regarding whether the SPG has completed its objectives as they were laid out in the scope of work.

1.4 Impact Evaluation Results

Table 1-1 compares the estimated BEC Program impacts that were calculated as part of this evaluation (using two Representative Day methods, two econometric modeling methods, and the BEC Peak Reduction method[5]) to those calculated by PG&E and the BEC, as well as those filed with the CPUC by PG&E. As this comparison shows, the two econometric models developed for this evaluation (an aggregate customer model and a site-level model) resulted in the most conservative impact estimates (8.5 and 11.7 MW, respectively). Both of the Representative Day methods resulted in impacts were similar in magnitude to those from the econometric models, however the 3-Day Morning Adjusted baseline method was the closest proxy to the modeling results (12.6 MW vs. 14.8 MW for the 3-Day unadjusted baseline). Being able to use the 3-Day Adjusted baseline as a proxy for the econometric results is a significant finding since it is believed that the econometric models produce results that are more robust and better at dealing with weather and day-of-week sensitivity issues that affect office and commercial buildings (which make up about 90% of the customers in this program) than the Representative Day methods. However, the Representative Day methods are easier to implement (they are similar to methods currently used for impact estimation and program settlement for other PG&E DR programs) and are reasonably transparent to participants which make them favorable for program settlement methods. The results from this evaluation support the CPUC's decision to switch to the 3-Day Morning-Of Adjusted baseline for program settlement for Program Year 2008.

Table 1-1 also shows that both the econometric modeling (the aggregate model is used to estimate ex post impacts) and the Representative Day baseline (used for settlement impacts) results are substantially smaller in magnitude than the results from the BEC Peak Reduction method (they are approximately one quarter the size). These results are similar to those from the 2005/2006 evaluation which illustrated that the currently settlement method is grossly overstating the program impacts. There are small differences between the BEC Peak Reduction impact estimates calculated by Itron, PG&E and the BEC (52.2, 51.8 and 52.4 MW, respectively). We believe these small differences result from the participants included in the calculations (Itron had to drop one of the notified participants since no Peak Demand value was provided for this customer).

[5] The BEC Peak Reduction method is the method that was utilized within the 2007 program year to calculate each participants load reduction for settlement purposes. It is calculated as the difference between a customer's average peak demand and their actual usage during the event.

Table 1-1: Comparison of Estimated Impacts across Evaluation Methods and with PG&E Reported Impacts and Program Goals

				Average Hourly Impact (in MW)									
				Evaluation Estimates					PG&E Estimates[3]		BEC Estimates[4]		
				Representative Day		BEC	Econometric Models		Rep Day	BEC			
Event Date	Start Hour	End Hour	Parts	3-Day	3-Day AM Adj	Peak Red	Agg[1]	Site Level[2]	3-Day	Peak Red	Peak Red[5]	Goal Credit[6]	Estimates Filed with CPUC[7]
7/5/07	14	19	73	11.7	9.5	51.1	10.7	11.9	8.1	48.7	54.3	24	49.5
8/29/07	13	18	95	11.4	13.3	47.9	12.1	11.6	12.6	51.1	47.4	29.9	45.1
8/30/07	13	18	98	10.8	13.3	48.5	11.2	11.7	11.3	47.4	46.7	30.2	44.9
8/31/07	13	18	98	24.5	13.7	61.1	0.7	11.7	24.1	60.1	61.3	30.2	57.9
2007 Avg				**14.8**	**12.6**	**52.3**	**8.5**	**11.7**	**14.4**	**52.0**	**52.0**	**28.9**	**49.4**

1 Based on the Aggregated Participant Ex Post Load Impact Models
2 Based on the Site-Level Participant Models
3 From BEC Load Event Files (provided by PG&E)
4 From BEC 2007 Performance_Enjoin Data.xls (received 7/8/08 from BEC Staff)
5 Peak Reduction Calculated as Peak kW (baseline) minus Average Usage during Event
6 Goal Credit Calculated as Peak kW minus FSL
7 From Dec 2007 Monthly ILP Report

Overall, the results generated as part of this evaluation show a good degree of consistency, but there are differences that call for discussion. Table 1-1 shows that the unadjusted 3-Day Representative Day baseline method resulted in settlement impacts that were relatively close to the 3-Day Adjusted method for the first three of the four events. For the final event, however, the 3-Day non-adjusted impact estimates were almost twice as large as those from the 3-Day Adjusted baseline. This is due to the morning adjustment for that event day which resulted in a substantial downward shift to the adjusted baseline. A review of this downward adjustment found it was appropriate since the weather for that day dropped nearly eight degrees over the previous two event days. Additionally, the event fell on a Friday before a holiday weekend, which typically has lower loads than the rest of the week. The opposite effect is seen in the aggregate econometric model, which was able to capture the calendar and weather effects associated with that day and resulted in drastically smaller impacts.

1.5 Findings, Conclusions, and Recommendations

1.5.1 Process Related Findings, Conclusions and Recommendations

The process evaluation conducted for the 2007 BEC Program found there were very high levels of satisfaction amongst Program participants in all areas (such as incentives offered, event notification process, the number of events called, etc.) It also found there are substantial programmatic changes being implemented for the BEC Program in 2008 (program settlement baseline method, incentive structure) which Program Managers fear could jeopardize this satisfaction and in turn program participation. We also found that marketing for the BEC Program seemed to be effectively bringing in customers who were unlikely to participate in other DR programs, and that the enrollment process, with the exception of making any changes to a customer's meter, was running smoothly.

The site assessments provided to BEC participants seem to be effectively helping them understand their energy use and subsequently develop effective load reduction protocols and event day curtailment plans. Participants have indicated a primary reason for their participation in this Program is to be a good corporate citizen.

Based on the Findings and Conclusions, this evaluation makes the following process related recommendations:

1. Conduct another process and impact evaluation in 2008 to determine how the changes implemented in 2008 have affected BEC participant satisfaction and event participation. Pay close attention to whether or not the Program still is effective at helping customers overcome the barriers they face to DR Program participation.
2. Talk with the PG&E personnel responsible for overseeing the technicians who make changes to customers' meters to determine if there is a way reduce the time BEC participants wait in the "metering queue" and thus delay their ability to fully participate in BEC events.
3. Continue to offer BEC participants comprehensive site assessments and revisit sites that have experienced changes to their building personnel or energy usage.
4. Consider increasing recognition of the BEC Program within San Francisco (through newspaper articles, etc.) to reward enrolled customers with good PR for their participation.

1.5.2 Impact Related Findings, Conclusions and Recommendations

The impact results from the 2007 evaluation confirm the findings from the 2005/2006 evaluation which indicated there were substantial issues with the methods used by the BEC Program to estimate event impacts. Again, in 2007 we found that the BEC peak demand reduction estimation method grossly overstates the impacts this program can realistically deliver on typical event days. The findings presented in this impact evaluation again illustrate there are significant advantages to using the representative day impact estimation methods for Program settlement (ease of use, transparent to participants, real-time calculation) and the econometric models for ex post evaluation as opposed to the BEC method. They also support the CPUC's decision to switch to the 3-Day Morning-Of Adjusted baseline for program settlement for Program Year 2008 since overall they come closest to the impacts resulting from the econometric models.

2

Introduction

2.1 Background

The Business Energy Coalition (BEC) Program is a third-party run tariff-based pilot demand-response program that was ordered in Decision (D.) 05-01-056, extended in D.06-03-024, and revised in D.06-11-049, D.07-12-048, and CPUC Resolution E-4163. The program began in 2005 as an initiative between PG&E and major San Francisco business and civic leaders to demonstrate the load curtailment capabilities that exist within commercial customers located in the San Francisco region of PG&E's service territory. The idea behind the BEC program was to form a cooperative comprised of PG&E commercial customers (primarily downtown office buildings and hotels) that can collectively commit to reducing their loads by a given amount on event days. This collective load reduction approach provides program participants opportunities to work together and make a significant reduction in energy demand on called event days when PG&E's electric supply is strained and the threat of rolling blackouts exist. As with all of PG&E's demand-response programs, the BEC program was designed to improve the reliability of electric loads for the customers in its service territory.

For the 2007 program year, the BEC program was available to all PG&E bundled-service, direct access, and wholesale customers in business sectors such as office, hospitality, and information technology. To be enrolled in the program, customers had to have a minimum average monthly demand of 200 kW and been able to reduce their demand by a minimum of 200 kW. Participants also had to take service on a PG&E demand time-of-use rate schedule, and have the required interval metering equipment installed and Internet access in place prior to enrolling in the BEC program. The customer eligibility requirements were revised slightly for the 2008 program year and these changes are included in subsection 2.1.2 for reference purposes.

2.1.1 2007 BEC Program and SPG Overview

The BEC program has been and continues to be managed by a third-party provider, a California nonprofit organization called The Energy Coalition.[6] As the program manager of the BEC demand-response program, The Energy Coalition is responsible for enrolling

6 The Energy Coalition website is http://www.energycoalition.org/.

customers into the program as well as managing the program's overall operation. Upon enrolling in the BEC program, customers must designate a Firm Service Level (FSL) that they will attempt to meet during program events and must demonstrate to PG&E that they can meet the program's minimum requirements. An engineering and/or site assessment is provided for some customers to identify load that can be curtailed during program events to help determine each member's FSL. The BEC estimates each customer's committed load reduction (CLR) by taking the difference between a customer's average peak demand and its FSL. During a program event, each BEC participant is expected to reduce its load to its prescribed FSL. Participants are paid based on their committed load reduction.

In the event of a program curtailment operation, PG&E will notify The Energy Coalition with as much advance notice as possible ranging from day-ahead to a minimum of one hour-ahead. In 2007, all events were day-ahead notification events. The program manager is notified by pager, e-mail, fax, and/or phone. The program manager is then responsible for informing each of the customers participating in the BEC program. Failure to receive a program operation notice does not release the program manager or a customer from their obligation to participate.

Program events will not exceed five hours per event, one event per day, five events per month, 25 hours per month, and 125 hours throughout the pilot period. Program events will be issued between 12:00 and 8:00 p.m. Monday through Friday, excluding holidays. The program will conduct a system test with each participant to assure energy reduction. In the event there are no actual curtailments, a two-hour test will be conducted every other month throughout the pilot program period.

A BEC program event may be triggered for actual or forecasted statewide or local shortages or emergencies throughout the pilot program period. Specifically, a program event may be issued when any of the following occurs:

- The California Independent System Operator (CAISO) declares that the electric service area known as NP15's spinning reserve level is below 7%,
- A Stage 2 emergency is issued by CAISO,
- The CAISO forecasted system load meets or exceeds 43,000 MW,
- The forecasted or actual temperature in San Francisco exceeds 78º Fahrenheit, or
- CAISO or PG&E declares a localized system emergency.

There were four events called for the BEC program in 2007, plus one test event on June 20, 2007 from 1:00 p.m. to 3:00 p.m. Table 2-1 presents the event dates, start times, end times, and event lengths in hours. Note that all four events lasted five hours but the first event, called on July 5, 2007, began and ended an hour later than the remaining events. One should also note that the second, third, and fourth events were called on consecutive days and occurred almost two months after the first 2007 BEC program event was called.

Table 2-1: Event Dates and Times for the 2007 BEC Program

Event Date	Notification Type	Event Period	Event Hours	Enrolled Participants	Notified Participants
June 20th 2007 (test)	*Day-Ahead*	*1-3pm*	*2*	*100*	*68*
July 5th 2007	Day-Ahead	2-7pm	5	111	73
August 29th 2007	Day-Ahead	1-6pm	5	115	95
August 30th 2007	Day-Ahead	1-6pm	5	115	98
August 31st 2007	Day-Ahead	1-6pm	5	115	98

At the outset of the BEC program, the incentive payment scheme began with each program participant receiving a payment of $50/kW annually based on its committed load reduction (otherwise referred to as a customer's fixed capacity available for curtailment). In 2007, this incentive payment was distributed in November. Non-performance penalties are assessed based on whether the group of participants at the time of the event reduce its load to the group's load curtailment level (i.e. penalties are not assessed based on an individual participant's reduction). Any penalties assessed are paid out of a shortfall reserve fund that is part of the program funding. If the funds are not used, they are proportionately distributed to participants at the completion of the pilot program or are carried over if the program extends beyond the pilot program termination date. The shortfall reserve funds for the 2006 and 2007 BEC programs were paid on June 26, 2008.

At the same time the BEC program originated, PG&E contracted with The Energy Coalition to lead a Special Projects Group (SPG) whose primary purpose was to develop an Integrated Demand-Side Management (IDSM) Alliance with the City of San Francisco. The SPG was designed by the former executive director of The Energy Coalition, John Phillips, to produce a broad range of IDSM services that could be offered to PG&E customers within the City and County of San Francisco. Activities of the SPG included (1) development of specific sets of non-traditional IDSM services that could be offered to PG&E customers with the goal of implementing programs that are at least as cost-effective as PG&E's current demand side management portfolio, and (2) the creation of a new "outside the box" IDSM model to help make demand-side management a sustainable and profitable way to enhance electric capacity. As part of its contract, the SPG was asked to provide two report deliverables to describe the best means for integrating energy efficiency and demand-response programs into an IDSM alliance and to define the evolution of an IDSM alliance between PG&E and local governments, including but not limited to the City and County of San Francisco.[7] The first report deliverable was presented in March 2008. Delivery of the second report, as of the middle of September, is still pending.

2.1.2 Recent BEC Programmatic Changes

The BEC program has operated in the manner described above since 2005. However, in February 2008, PG&E submitted an advice letter to the California Public Utilities Commission containing proposed modifications to the program for 2008 and beyond. The modifications include changes to the program's settlement baseline, incentive payment structure, performance penalties, and customer base. These changes are intended to increase the load reductions garnered from the program on event days, thereby improving the reliability of PG&E's energy supply in the transmission-constrained San Francisco Bay Area and throughout the PG&E territory. On May 15, 2008, the CPUC adopted Resolution E-4163 in which it approved a number of the proposed modifications suggested by PG&E.[8]

PG&E's advice letter regarding the recommended BEC program changes stated, "PG&E proposes to reduce fixed capacity incentives and increase the performance-based incentives for delivered demand reductions."[9] The fixed capacity incentive (where "fixed capacity" is the amount each customer has available to curtail for an event, i.e. the CLR) will be reduced to a maximum of $25/kW and will be based on the averaged delivered capacity of the season, up to that customer's maximum committed load reduction. The previous fixed capacity incentive was $50/kW. Also, instead of basing the performance payment completely on the *group's* load reduction, PG&E proposes to weight it more heavily on the performance of individual participants and to make the payment dependent on where the customers are located. The performance payment will increase to $50/kW (up from $25/kW), 50% of which will be based on individual performance and the remaining 50% on the group's performance.

The baseline methodology used for the BEC program is also revised in the advice letter to better reflect the temperature variations experienced by program participants. In PG&E's advice letter, it proposed to divide BEC customers into two geographical groups (Zone 1 and Zone 2) and use different baseline methodologies for each zone.[10] Zone 1 includes the customers located within San Francisco, South San Francisco, Daly City, and Half Moon Bay. The BEC customers located outside these locations comprise the customers in Zone 2.

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7 Description of the Special Projects Group was derived from Exhibit A of PG&E Service Contract #4600017251 between PG&E and The Energy Coalition.

8 Resolution E-4163 issued by the California Public Utilities Commission regarding proposed modifications to PG&E's Business Energy Coalition Program, submitted in Advice Letter 3213-E.

9 Page 2 of PG&E's Advice Letter 3213-E submitted to the CPUC, dated February 22, 2008.

10 Page 3 of PG&E's Advice Letter 3213-E submitted to the CPUC, dated February 22, 2008.

The E-4163 Resolution issued by the CPUC on May 15, 2008 approved a 10-in-10 baseline for Zone 2 customers and approved a 3-in-10 baseline with optional morning hour adjustment for Zone 1 customers. If Zone 1 customers choose the morning adjustment, their selection will be enforced throughout the season. The morning adjustment, according to the CPUC, "shall incorporate the participant's four hours of energy use prior to an event. This modification will deter participants from intentionally increasing their loads as a way of gaming the baseline."[11]

The customer eligibility has also been revised slightly for the 2008 program year to focus on hard-to-reach customers. For the 2008 BEC program, this set of customers has been defined as "customers that (a) have never participated in a PG&E demand response event and (b) have rejected enrollment in at least one PG&E demand response program other than the BEC program."[12]

During the 2009-2011 program cycle, PG&E plans to offer the automated BEC program (A-BEC) to PG&E customers located in the city of San Francisco and the BEC program to those customers outside of the city. These programs share virtually all of the characteristics of the 2008 BEC program. This set of program participants represent the most likely participants of the A-BEC program as they continue to qualify with the program's eligibility requirements.

The programmatic changes described in Section 2.1.2 did not affect the 2007 program operations, and are only included in this report for reference.

2.2 Evaluation Objectives

The principal objectives of this evaluation included the following.

- Conduct process evaluations of the 2007 BEC and 2005-2007 SPG programs, report findings, and make recommendations to enhance the operation of these programs.
  - Itron collected available marketing and field data, interviewed program staff, analyzed the gathered data, and compared findings from this information to program theory and plans.
  - Itron surveyed BEC program participants to assess the event notification process, motivation to participate in the program, knowledge of demand response in general and the BEC program in particular, and potential barriers to new and continued participation.
  - Interviews with program staff were used to assess BEC program marketing and outreach efforts, management of event calls, recordkeeping of activities, and overall program effectiveness.

[11] Page 12 of CPUC Resolution E-4163.

[12] Schedule E-BEC—Business Energy Coalition Program. Attachment 1of PG&E's Advice Letter 3213-E submitted to the CPUC, dated February 22, 2008.

- Using 2007 load data supplied by PG&E, develop estimates of the BEC program peak period impacts by reporting estimated load reduction for each event and for the 2007 program year.
  - Program settlement impacts were calculated based on a variety of representative day baseline methodologies currently used in California.
  - Adjustments based on weather and/or pre- or post-period usage ratios were made.
  - An aggregated regression analysis including BEC participants who were involved in all four 2007 events was conducted to estimate event day and overall program impacts for the 2007 program year.
  - Individual site-level econometric regression models were developed to estimate the baseline loads as well as estimate the individual event day ex post load impacts for each individual hour in accordance with the California demand response impact evaluation protocols.
- Compare alternative load reduction impacts estimated for the 2007 BEC program.
  - Estimated impacts, both settlement and ex post, were compared to program goals.
  - Load impacts were broken out by event and hour for each estimation method.

2.3 Organization of Report

This report consists of five sections.

- **Section 1 (Executive Summary)** summarizes the high-level findings of the study and provides recommendations for future analysis.
- **Section 2 (Introduction)** provides an overview of the BEC program and states the study objectives and report organization.
- **Section 3 (Process Evaluation)** presents findings from in-depth program staff interviews and program participant interviews regarding the operation of the BEC program and also presents a brief review of the operation of the SPG Program.
- **Section 4 (Impact Evaluation)** includes a description of the methodology used to estimate the impacts of the BEC program and the evaluation results.
  - **Impact Evaluation Methodology** summarizes the methods and data sources used to calculate program impacts and details the participant population and program year events.
  - **Impact Evaluation Results** provides the final impact estimates based on representative day (settlement impacts) and regression methods (ex post impacts) and compares these impacts with program goals and reported accomplishments.
- **Section 5 (Findings, Conclusions, and Recommendations)** presents the findings and conclusions drawn from the analysis results. It also makes recommendations

regarding the impact methodology BEC should rely upon to improve the accuracy of its estimates of load reduction garnered from the program.

The report also contains supporting materials in six appendices:

- **Appendix A (Program Staff Interview Guide)** provides a list of topics and questions that Itron has developed as discussion points for program manager and staff interviews with individuals involved in the BEC program and the SPG.
- **Appendix B (Program Staff Interview Results)** contains the main findings from Itron's interviews with individuals involved in the BEC program from PG&E and The Energy Coalition.
- **Appendix C (Post-Event Survey)** includes a copy of the questions asked of 2007 BEC program participants during the post-event survey. This survey was fielded by Itron's CATI center.
- **Appendix D (Post-Event Survey Data Tables)** provides frequency tables of key questions from the post-event survey including those addressing program satisfaction, actions taken by the participants during events, the collective nature of the BEC, and program assistance received by the BEC program manager.
- **Appendix E (Representative Day Baseline Event Day Load Shapes)** contains graphs of the event day load shapes (resulting from the actual event day load and the representative day baseline analysis) across all of the active BEC participants for each of the BEC event days in 2007.
- **Appendix F (Aggregate Model Econometric Ex Post Impact Estimates)** presents the regression model results in accordance with the California Demand Response Impact Evaluation Protocols.

3

Process Evaluation of 2007 BEC Program and 2005-07 Special Projects Group

3.1 Process Evaluation of the 2007 BEC Program

This process evaluation reviews and assesses implementation-related aspects of the 2007 BEC program including participant program satisfaction, the marketing and sign-up process for the program, and the demand response program barriers that the BEC program was designed to overcome. The main sources of information used to complete this process assessment stems from interviews conducted with key managers and staff affiliated with the BEC program and from PY 2007 participant responses to a post-event survey[13].

A series of interviews was conducted with both PG&E and BEC program staff in June 2008. These interviews discussed program design, processes, and effectiveness. The individuals interviewed for this evaluation include the manager of the BEC program, Leanne Hoadley, an analyst of the BEC program, Helen Arrick, and a BEC program analyst at PG&E, Mike Cristofani. During the same period, the Itron team also attempted to set up a key actor interview with John Phillips, former executive director of The Energy Coalition and one of the program's primary developers. Unfortunately, due to circumstances beyond Itron's control, it was not possible to conduct this interview.

In order to assess the program's processes, the Itron team discussed a number of issues with BEC personnel including program marketing and outreach efforts, engineering site assessments and the determination of load reduction capabilities, event management, incentive payment structure, and the cooperative nature of the BEC Program. Other areas of focus included discussion of the changes to BEC for program year 2008 and the forecasted impact of these changes, and recommendations on future improvements to the BEC Program.

The post-event survey was completed by Itron's CATI center in May 2008. Of the 116 program year 2007 BEC participants, 54 respondents completed the phone survey. The following topics were covered by the survey.

[13] The post-event survey is included in Appendix C of this report. Survey response frequency tables for key questions are in Appendix D.

- Participant characteristics,
- Reasons for participation,
- Barriers to participation,
- 2007 BEC events,
- Program assistance,
- Program satisfaction, and
- Recommendations for program improvements.

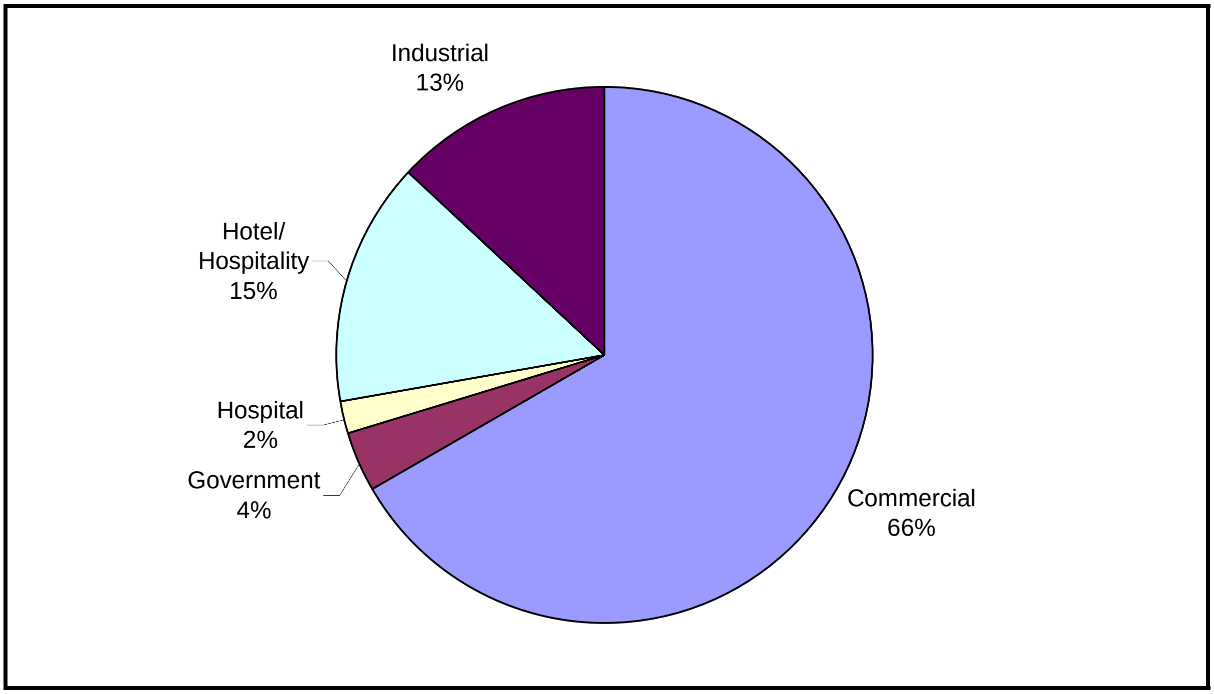
3.1.1 Participant Self Reported Survey Results

This section presents a summary of the results from the post-event survey. Complete results are shown in Appendix D.

Participant Characteristics

All BEC participants were asked a series of demographic questions to determine the types of customers enrolled in the BEC program. Figure 3-1 shows that most of the customers enrolled in the BEC program are commercial businesses, followed by hotel/hospitality businesses.

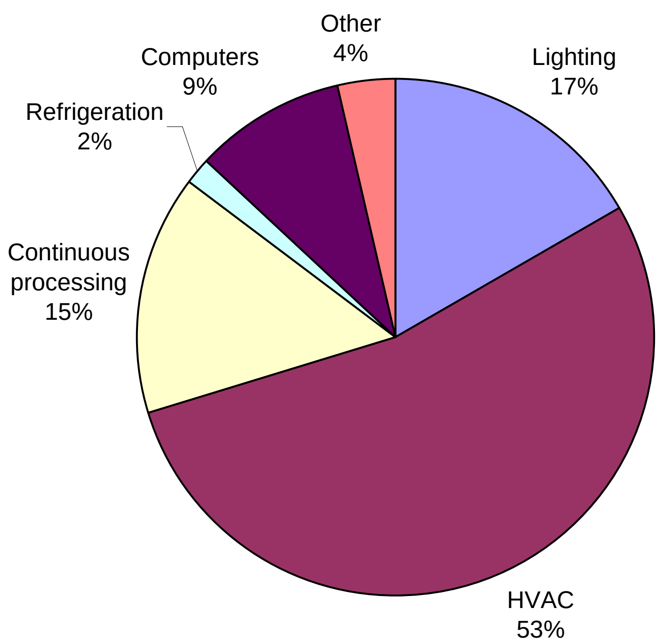
Figure 3-1: Main Business Activity of Company



Participants were asked what percentage of their organization's total annual operating costs was attributable to energy-related spending. Over half (52%) reported that energy costs accounted for 10% or less. On average, across all of the BEC participants surveyed, energy costs represented approximately 11% of their annual operating expenditures.

Figure 3-2 shows the distribution of the largest end use at each surveyed facility (kWh). As this figure shows, for most BEC participants the largest electrical end use at their facility is HVAC (53%), followed by lighting (17%). This is to be expected considering that two-thirds of the BEC participants are commercial businesses.

Figure 3-2: Largest End Use at Facility in Terms of Electrical Consumption

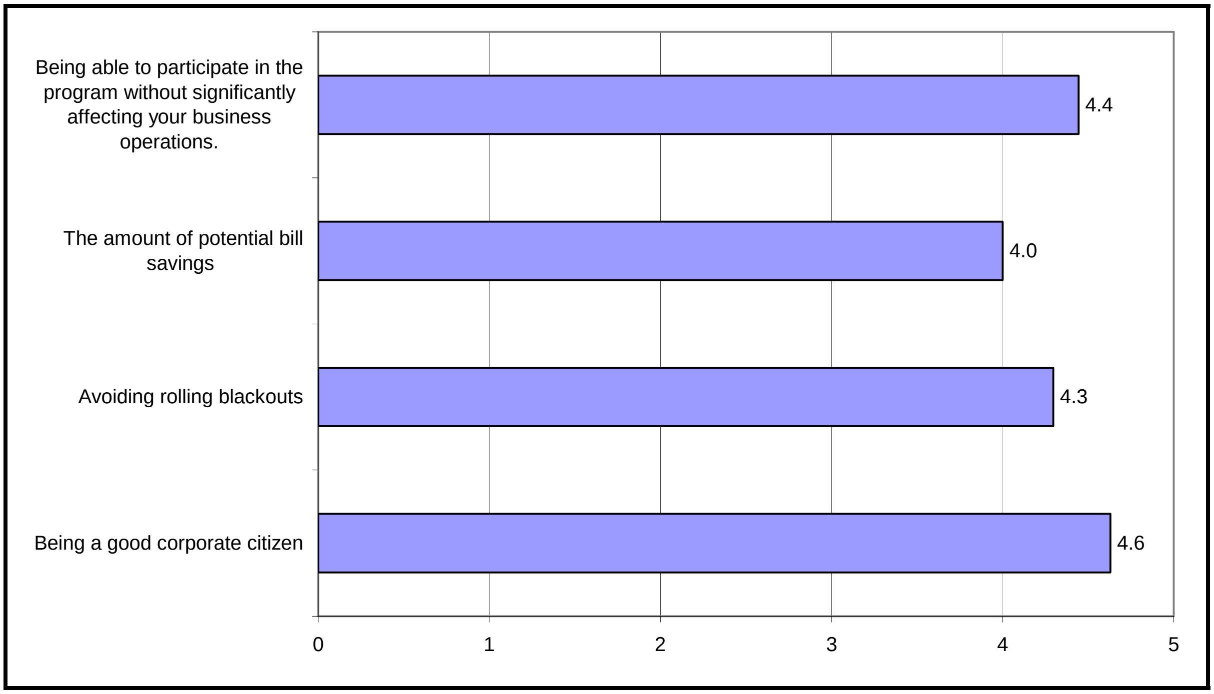


As mentioned earlier, the BEC program was designed to attract customers classified as "hard to reach" with respect to demand response—those with little or no previous participation in demand-response programs due to a variety of reasons (e.g. office tower with dozens of tenants). Questions were asked of survey respondents to determine their history with demand-response programs and 50% reported that PG&E had attempted to recruit them in the past for another demand-response program (20% stated they could not remember). Of those recalling recruitment, 70% reported participation in another demand-response program at some point in the past (eight for the Demand Bidding Program, three for Critical Peak Pricing, and one for the Scheduled Load Reduction Program). Aside from the DBP, these BEC program participants were *past* participants of the CPP or SLRP, since BEC does not allow their participants to be part of either of these programs simultaneous to the BEC program. Two-thirds of those who were recruited and signed up for a demand-response program reported dropping load for their other program. In total, 22% of those surveyed reported participating in another PG&E demand-response program.

Reasons for Participation

BEC participants were asked to rate the significance of a variety of reasons for participating in the BEC Program on a scale of 1 to 5, where 1 was "insignificant" and 5 was "extremely significant." Figure 3-3 below shows the average significance reported for each reason given.

Figure 3-3: Significance of Reasons for Participation

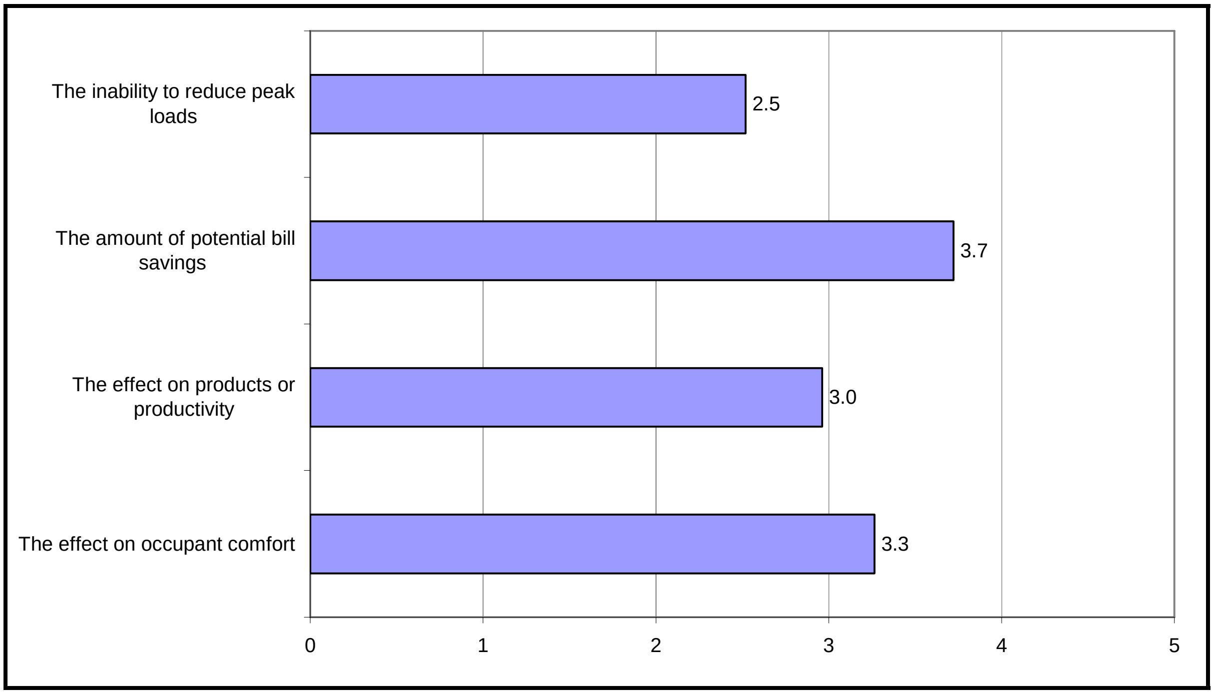


Overall, "being a good corporate citizen" was the rated the most significant reason for BEC participation with nearly 75% of the respondents reporting it was "extremely significant" and no one reporting it was "insignificant." "The amount of potential bill savings" had the lowest significance rating of the reasons to participate; however, it still averaged 4.0 on a scale of 1 to 5. This shows that BEC participants find this feature of participation valuable on an absolute scale. The fact that "being a good corporate citizen" has a higher significance ranking than "the amount of potential bill savings" leads one to believe that BEC is attracting customers who are a good fit for a cooperative program such as BEC.

Reasons Not To Participate

BEC participants were also asked to rate the significance of a variety of reasons that might keep customers from participating in the demand-response programs on a scale of 1 to 5, where again, 1 was "insignificant" and 5 was "extremely significant." In other words, this set of survey questions tries to illicit from participants the reasons why they might not feel it is worth participating in the BEC program. Figure 3-4 below shows the average significance reported for each of the reasons. Note that these significance rankings are not relative. Each participant was asked to rate each of these four reasons and that participants may have multiple reasons why they think it may not be worth participating in the BEC Program.

Figure 3-4: Significance of Reasons Not to Participate



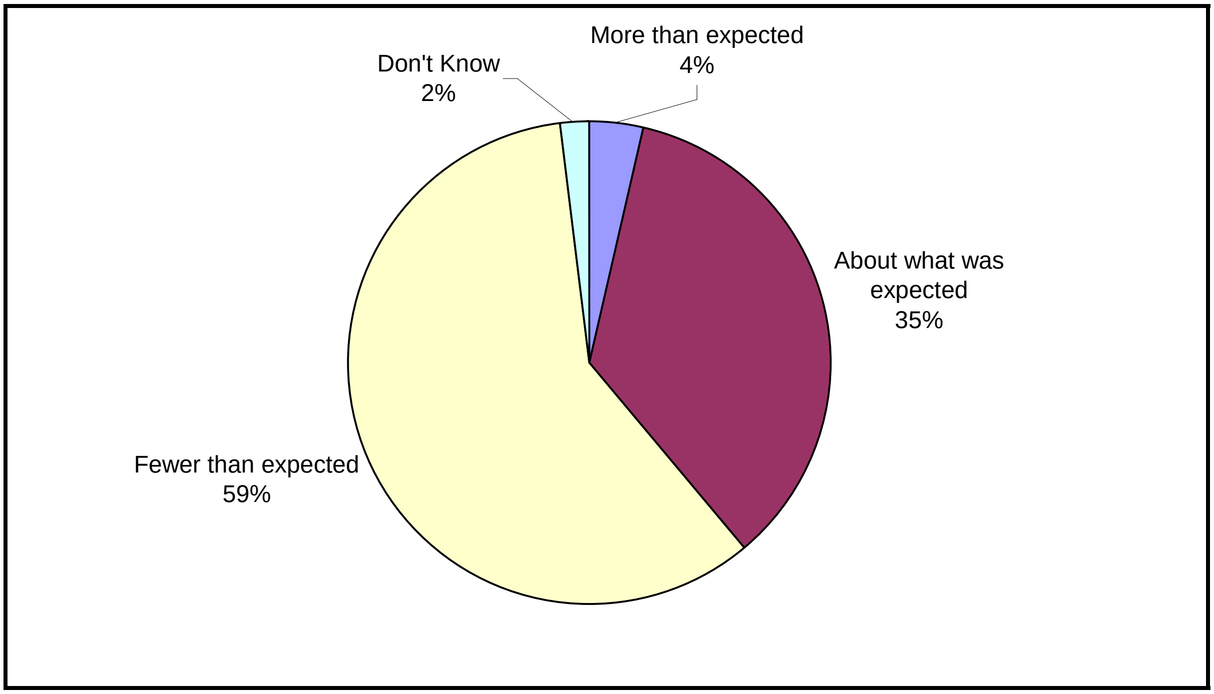
As this figure shows, "the amount of potential bill savings" ranks as a significant reason not to participate, meaning that participants did not find the amount of bill savings to be enough of an incentive to participate. It is also interesting to note that considering the population of customers enrolled in the BEC Program (primarily office buildings), 41% of customers reported that "the inability to reduce peak loads" was an "insignificant" concern. This reason is perhaps considered insignificant because the participants are confident of their ability to reduce their peak loads and therefore do not consider it a barrier to participation.

2007 BEC Events

During the survey, BEC participants were asked a number of questions regarding the BEC events that took place during the summer of 2007. These questions focused on their recall of the events, the notification they received for the events, their actions during the events, and the impact these actions had on their overall operations.

Participants were asked to recall how many BEC events had occurred during the summer. Thirty seven percent said they believed there were five or more (in actuality there were four events called on July 5, August 29, August 30, and August 31, and a test event was held on June 20 from 1 p.m. to 3 p.m.). Figure 3-5 shows that for most BEC participants (59%), this was fewer than what they had expected, or on a par with expectations (35%). Only 4% stated it was more events than they expected. This indicates the information being given to the BEC participants regarding expectations of the number of BEC events in the 2007 program year was realistic.

Figure 3-5: How did the Number of Events Compare to what you Expected?



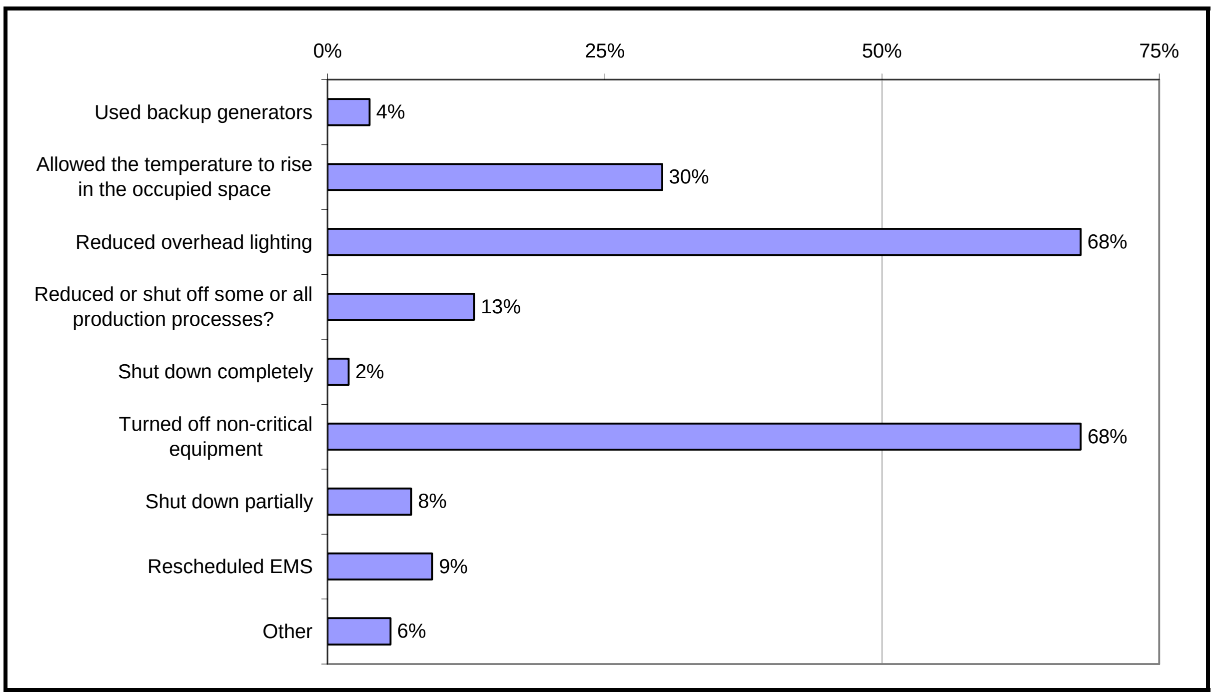
When signing up for the program, BEC participants are able to select how they would like to receive notification about curtailment events that are called. Eighty-seven percent of those surveyed indicated they received notification via e-mail and 41% indicated they received a phone call (31% received notification by both phone and email notification). All participants surveyed who had received notification about one or more events reported that they felt the notification process was effective, with 92% reporting it was "very effective" and 8% reporting it was "somewhat effective." The four events in 2007 were all day-ahead events, meaning participants were contacted and told of the event the day prior to the event. Thus, participants received approximately 24 hours to prepare themselves for the curtailment event that was about to occur. When participants were asked about the amount of time needed to curtail their load for an event 54% reported they needed two hours or less, 18% reported they needed between two and eight hours and 28% reported they needed more than eight hours. Based on these responses, nearly all of the participants should have received enough warning to be able to respond to the 2007 BEC events. However, if a day-of event was to be called (with a minimum program of one hour), nearly half of the participants would not have enough advance warning to be able to fully respond.

Eighty-seven percent of BEC participants reported that they participated in all of the 2007 BEC events (participants who thought there were no events or who could not estimate the number of BEC events in 2007 were removed from this calculation). Participants who did not curtail their load for one or more of the events gave the following reasons for not participating:

- "Operation was already shut down,"
- "Could not respond in time,"
- "Could not reduce load on that particular day," and
- "Did not receive event notification."

Participants were asked what type of actions they took in response to the most recent event in which they participated. Figure 3-6 provides a listing of their responses. As this figure shows, reducing overhead lighting and turning off non-critical equipment were the most frequent actions reported by the participants surveyed.

Figure 3-6: What Curtailment Actions did you take in Response to Recent BEC Events?



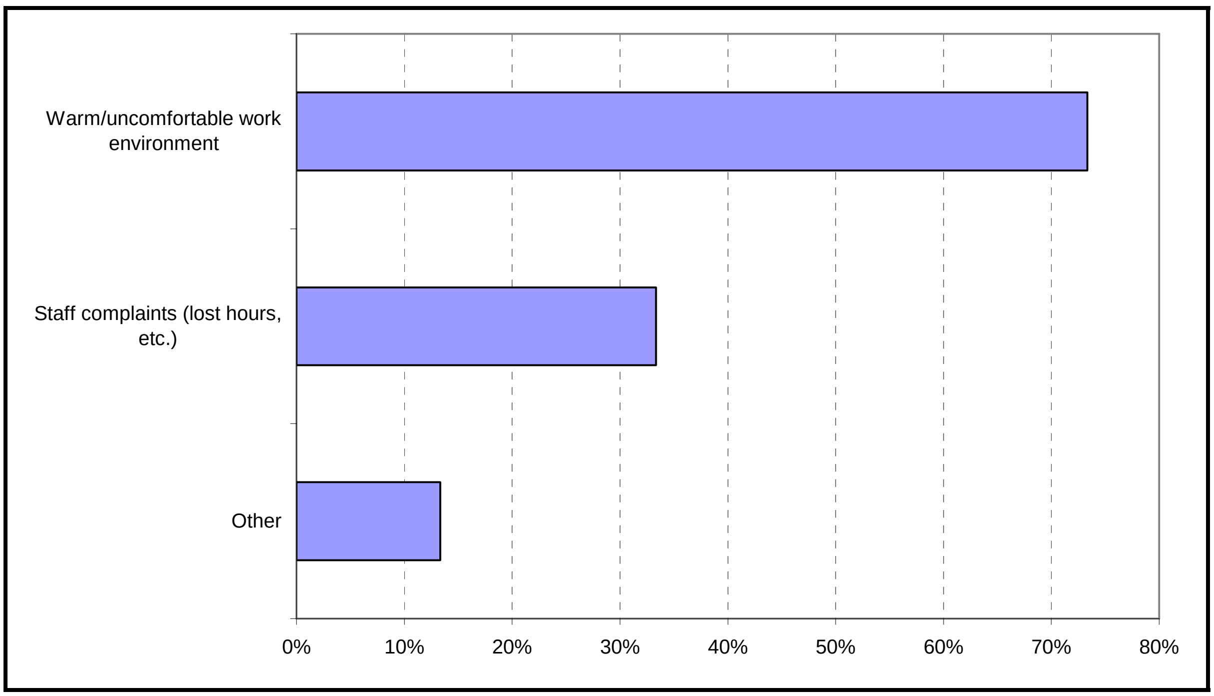
Note: EMS stands for automated Energy Management System.

Participants were asked about the level of automation they used in their response to the curtailment events. Of those surveyed, 49% reported their actions were manual, 47% stated they were partially automated and 4% said they were fully automated. On average, BEC participants estimated that their curtailment actions resulted in a 10% reduction in their overall load.

BEC participants were also asked whether they increased their energy use prior to the curtailment events to make up for the load reduction that was to occur and 13% responded that they had done so (primarily pre-cooling and/or running extra shifts in the off hours). When asked whether they had increased their energy use after the event only 7% reported they had done so.

When BEC participants were asked whether their event curtailment actions had any impacts on personnel comfort or productivity, 28% of respondents indicated that they had. Figure 3-7 shows that, of those impacted, the primary impact experienced was a warm or uncomfortable work environment.

Figure 3-7: Primary Impacts Experienced as a Result of BEC Participation



Most BEC participants (85%) reported feeling that their organization was very well prepared to manage the demand reductions called for by the BEC program during the summer of 2007. The primary reasons reported for being inadequately prepared for the BEC events resulted from inadequate internal communication and preparedness on the part of the participants.

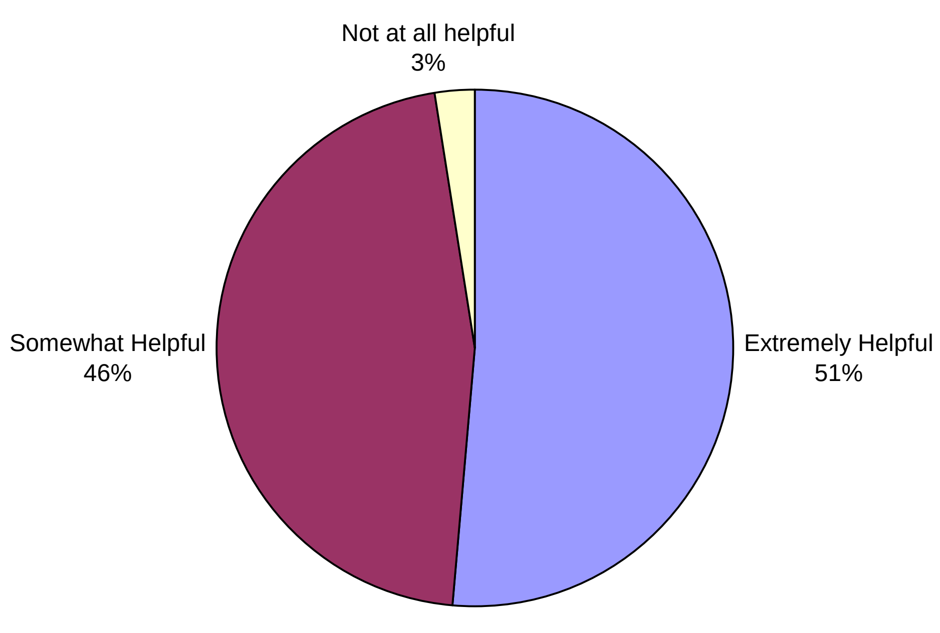
Program Assistance

The BEC participants surveyed were asked a series of questions concerning the assistance they received, with respect to setting their Firm Service Level (FSL) and developing load reduction strategies, from the BEC after enrolling in the program. Seventy-four percent stated they were given guidance on setting their FSL, and nearly 70% of those stated the guidance was very helpful. Only four of the customers surveyed reported they had changed their FSL during the program year (7%) and of those, two increased it and two decreased it. When asked how they determined their FSL, the responses included the following:

- BEC, PG&E, or ASW Engineer told them what to set it at (35%),
- Used their past bills and/or energy use (35%), and
- Based it on their peak demand (7%).

Seventy-four percent of customers reported that after signing up for BEC they had received an on-site technical assessment to assist them in developing a curtailment plan for BEC events. Those who had received the on-site assessment were asked to characterize how helpful this assistance was in responding to BEC curtailment events. As Figure 3-8 shows, 97% of BEC participants thought the assistance was somewhat or extremely helpful.

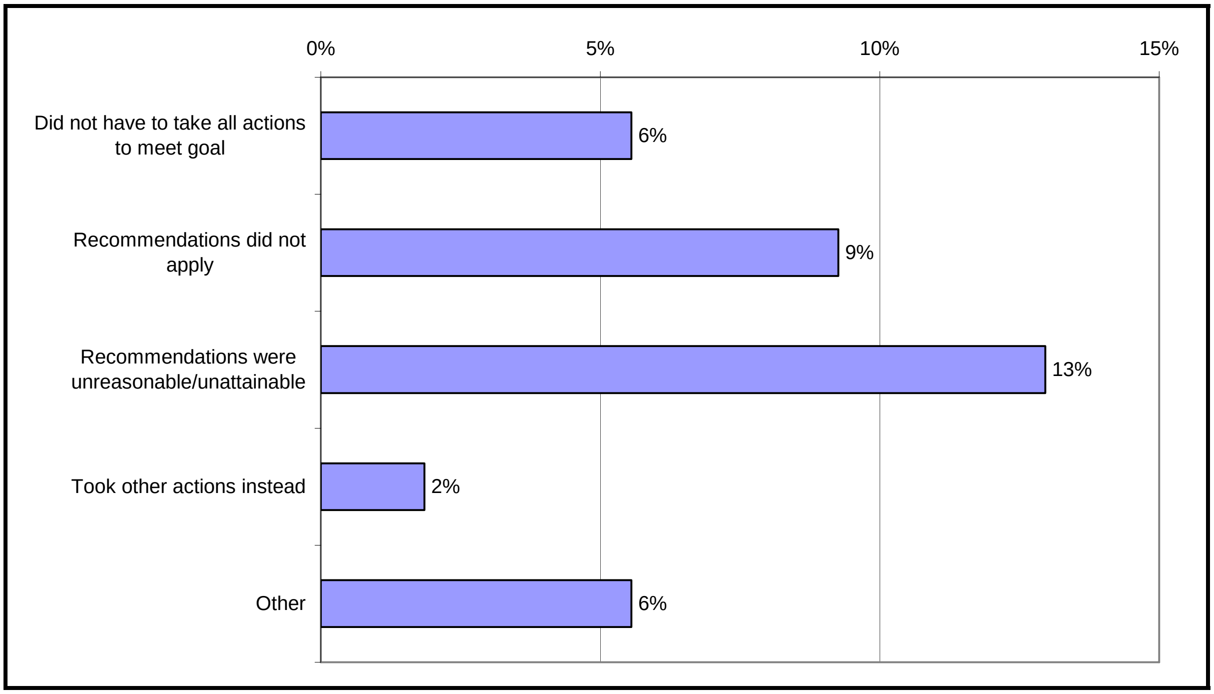
Figure 3-8: Characterization of Technical Assistance Provided to Participants



When asked about how many of the actions prescribed by the audit they took during curtailment events, 97% responded “all of them” or “some of them” (equally split 49% and

49%), while only 3% responded "none of them." Figure 3-9 provides the reasons participants gave for not taking the recommended actions during BEC events. It is interesting to note that 13% reported that the recommendations were unreasonable or unattainable; however, they did not elaborate on whether this was for the particular event or for all events in general. Other reasons given included "notification was not received," "it wasn't a real event," and "tenant comfort and day operation issues."

Figure 3-9: Reasons for Not Taking Suggested Actions during Curtailment



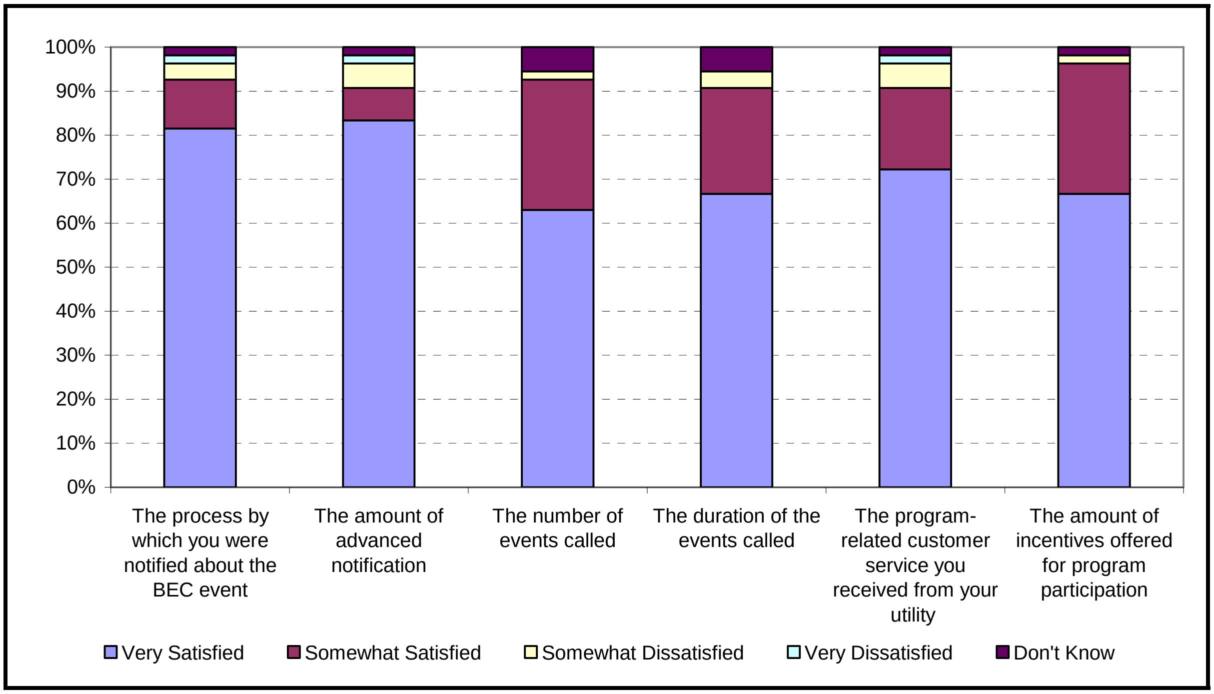
Overall 80% of those surveyed said they felt their organization received as much support as they needed in the development of load reduction strategies.

While 78% of survey respondents indicated there was nothing that PG&E or the BEC could do to assist them in taking demand-response actions for future BEC events, 7% stated that earlier notification would help. Other areas for future assistance included recalculating FSL, additional training on the website, more program information for tenants, and increased incentives.

Program Satisfaction

To evaluate participant satisfaction with the 2007 BEC program, a battery of questions was included in the post-event survey. Topics covered include satisfaction with the event notification process, the level of assistance by The Energy Coalition to identify load reduction options, the number and length of demand response events, and the incentive payments received for participation in events. Figure 3-10 shows the levels of satisfaction reported in each of these areas.

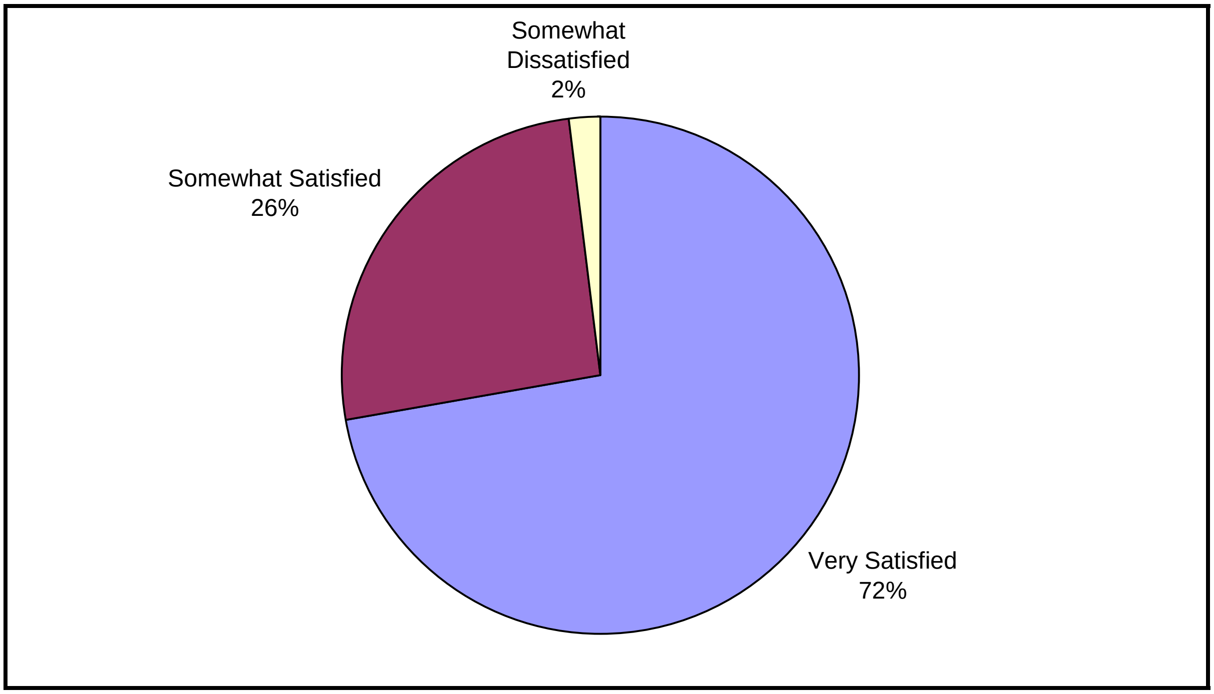
Figure 3-10: Satisfaction with Program Elements



Since there was no "neutral" response, a good indication of satisfaction is provided by the percentage responding that they were either very satisfied or somewhat satisfied with a particular aspect of the program. Using this indication, each of the areas had more than 90% of the participants reporting they were satisfied. The highest level of satisfaction reported was for the value of the incentives offered (96%); however, one-third of these were only somewhat satisfied.

When asked about BEC program satisfaction on the whole, 98% of those interviewed reported they were very or somewhat satisfied. No respondents reported being very dissatisfied. Figure 3-11 shows the breakdown of overall satisfaction across the satisfaction categories.

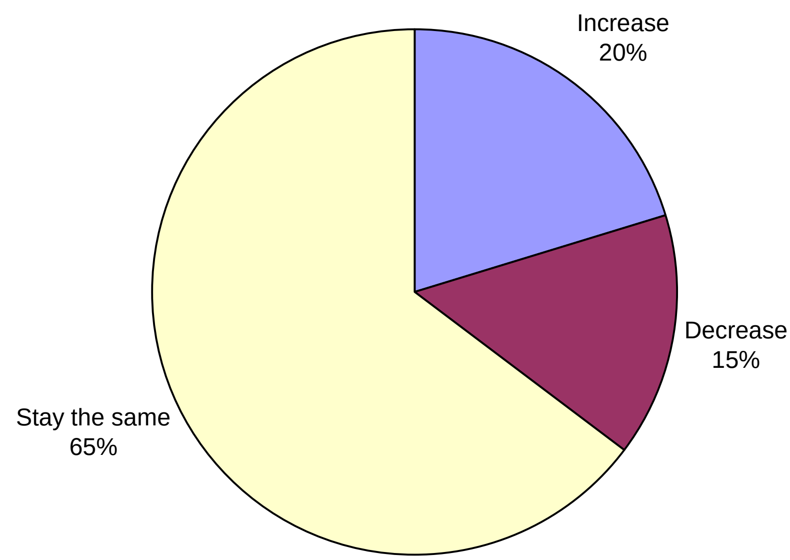
Figure 3-11: Overall Program Satisfaction



The BEC program was designed as a collaborative program where participants work together to meet a group designated demand reduction goal. When asked about this aspect of the program, 96% of participants surveyed reported knowing about the collaborative nature of the program. Most participants reported that the collaborative nature of the program did not make them feel any less obligated to participate in the curtailment events (only 5% reported feeling less obligated); however, 93% reported that they did not work with other participants when making demand reductions (e.g., trade off demand reductions across events). Nearly three-fourths of those surveyed reported that the collective nature of the program was an attractive feature to their company.

All 54 participants surveyed reported that they planned to continue their participation in the BEC program during the summer of 2008. More than 50% of those surveyed stated that they plan to continue their participation for environmental or corporate citizen type reasons ("it is the right thing to do," "global warming," "to be green," etc.). Thirty-seven percent mentioned "saving money" as a reason for their continued participation. As Figure 3-12 shows, most of those surveyed anticipate that their future load reductions for BEC events will increase (20%) or stay the same (65%), which bodes well for the future of the BEC program.

Figure 3-12: Estimated Change in Load Reduction for Future BEC Events



Recommendations for Program Improvements

BEC participants were asked to provide suggestions for improving the BEC program. Seventy-two percent could not think of any improvements to be made. Those who did offer recommendations suggested the following improvements:

- Increasing the incentives given for program participation (9%),
- Better feedback regarding participant performance during the program (6%), and
- Improved communication/updates on the program (4%).

3.1.2 Program Marketing and Sign-Up

Program Marketing

Marketing for the BEC program is different from the marketing of PG&E's other demand-response programs due to the nature of the customers targeted for the BEC program. Materials provided to Itron from the BEC program managers described the target market as "customers who are difficult to recruit or have not consistently or significantly participated in load reduction events."[14] These customers tend to be office buildings, hotels, hospitals, and

[14] Following the 2007 summer season – and thus technically beyond the scope of this evaluation – the CPUC clarified the definition of hard-to-reach customers in D.07-12-048. The Decision states "We modify Resolution E-4079 to define "hard-to-reach customers" for purposes of customer eligibility in the Business Energy Coalition demand response program as customers that (a) have never participated in a PG&E

other businesses that are unable to reschedule or shut down production process when a curtailment event is called. These customers are classified as "hard-to-reach" (HTR) within the demand-response portfolio and the BEC program arose in order to motivate these customers to become involved in demand response.

Although it is possible for a PG&E customer to learn about the BEC program from PG&E's website, the primary source of BEC marketing is done by PG&E account representatives and BEC program staff. PG&E account representatives and BEC staff work closely together to identify customers who would be a good fit for the BEC program and who were currently not enrolled in a demand-response program. Once a potential customer has been identified, BEC staff contact the customer to schedule a BEC presentation that provides detailed information on how the BEC operates and to answer any utility-related questions the customer might have. BEC staff is quite knowledgeable about the demand-response programs available to PG&E customers and often provide information about alternate demand-response programs to ensure that the customer is matched with the "most appropriate demand-response program for their business."

Program Sign-Up

The current procedure to get a customer enrolled and capable of participating in BEC program events includes the following steps.[15]

1. Customers wishing to enroll sign a Memorandum of Understanding (MOU) with The Energy Coalition (Coalition) and a Third Party Agreement with PG&E authorizing the BEC to review their meter data. Account sales and service managers confirm the customer's rejection of at least one other demand-response program (a new 2008 requirement to participate in BEC).
2. Each facility is offered an engineering assessment by Coalition engineers, in order to determine the building's load reduction capacity. Though this is not required for participation, participants typically opt to have their facilities assessed. BEC engineers review the customer's peak load data prior to their building assessment, in order to accurately estimate load reduction potential. This assessment informs the creation of a curtailment protocol report.
3. Each facility receives a hard copy of their curtailment protocol report. BEC staff will review the hard copy report with the facility engineer(s) and, if applicable, property management to get final approval on their individual curtailment protocol procedures and kW commitment amount.

demand response program event and (b) have rejected participation in at least one PG&E demand response program other than the BEC."

[15] These procedures were provided to Itron from the BEC Program managers.

4. Each facility must have pulse-ready meters installed. In order to determine if the facility's meter(s) are pulse-ready, PG&E's metering department will assess the meters at each location. Where meter upgrades are required, PG&E will complete the upgrade work. The Energy Coalition covers all costs associated with meter upgrades. This process can take 30-60 days.
5. Each facility identifies one of three forms of communication (phone line, Ethernet or DSL) in order for the gateway real-time metering device to collect and transmit meter data. If one of these communication channels is not available at the meter location, the facility must order the installation. The Energy Coalition covers the costs of installation.
6. Each facility has a gateway device installed at their meter(s). The gateway installation is done by a Coalition electrical engineer.
7. Once the gateway is installed, the pulse data from that gateway is verified by comparing it to historic PG&E interval meter data.
8. Each facility receives training on the online real-time meter data website (Enjoin). This allows the facility to monitor their electric energy usage online at anytime from a password protected website.
9. Each facility receives an "Energy Action Day" alert poster, for building lobbies or common areas, building occupant tips sheets, and tenant notification text for property managers to customize and use for announcing curtailments via email prior to each event.

BEC staff reported that this enrollment process progresses fairly smoothly, however there are a few activation steps that can extend the enrollment process and lead to significant delays to the customer's full participation in BEC events. These steps include:

- Making changes to a customer's meter (most customers already have interval meters however may need a pulse box installed or phone lines split). Meter changes require waiting in PG&E's metering queue which can be quite long during the curtailment season;
- Establishing a wireless signal from the meter to gateway (approval for PG&E network cards, troubleshooting); and
- Time customer takes to install phone line and/or Ethernet connection and to run conduit from remote meters to gateways.

The BEC has started classifying customers who have encountered these delays as "Callable" and encourages them to participate in BEC events, even though they will not be able to see their real-time data in the Enjoin system. These customers have received their BEC engineering assessment and curtailment protocols that gives them the information needed to participate in an event. During this interim "Callable" period interval data is requested from PG&E after an event has occurred in order to measure the customers' performance. In 2007 the capacity payment a customer received was a one-time payment that did not reflect at what point during the curtailment season the customer enrolled in the program[16], which provided an incentive for BEC to get all customers participating in BEC events as soon as possible. At the time when a customer is declared "Callable" they are far enough along in the enrollment process that they are able to receive both phone and e-mail event notifications.

3.1.3 Barriers to Demand Response and Resulting BEC Program Design Elements

As mentioned in the section above the target market for the BEC program is HTR customers, defined as "customers who are difficult to recruit or have not consistently or significantly participated in (DR) load reduction events." BEC program managers provided the Itron team a document summarizing six of the primary barriers to demand-response these HTR customers face and that the BEC program was specifically designed to address. These barriers are summarized below.

- **Barrier 1: Overall Customer Risk Aversion.** Commercial customers perceive risk to critical operations, tenant lease agreements, and productivity.
- **Barrier 2: Commercial Sector's Perceived Inability to Reduce Load During Peak Hours.** Statewide peak demand coincides with the peak demand in commercial buildings.
- **Barrier 3: Lack of Demand-Response Enabling Technology.** Many large commercial customers do not have the equipment necessary to participate effectively in demand response programs or to view their participation and performance.
- **Barrier 4: Lack of Demand Response Protocol Expertise.** Building engineers and property managers who have not previously participated in a demand response program may not feel confident in altering critical building systems during curtailment events.
- **Barrier 5: Commercial Lease Agreements and Restrictions.** Many tenant leases require indoor temperatures remain at fixed range.
- **Barrier 6: Complicated Program Requirements.** Many demand response programs require significant staff time to implement, monitor, and track. The baselines are difficult to determine from one curtailment event to the next.

The BEC program was specifically designed to address the barriers presented above in order to capture the demand-response potential of "hard-to-reach" customers. The program elements that address these barriers include the following.

[16] In 2008 capacity payments were prorated to reflect at what point during the curtailment season the customer enrolled

- **Detailed Site Assessments.** These site assessments educate building engineers and property managers on demand-response actions that can be taken at specific locations and the expected kW impact of these demand-response actions.
- **Simplified Program Requirements.** A key goal of the BEC program was "to provide customers with clear, concise and transparent reduction goals, minimizing the customer burden of calculating complex reduction requirements…" To help participants overcome this barrier, the BEC was initially implemented using a "peak" baseline that was calculated as the maximum two-year average peak summer (June through September) demand. This baseline was a constant for an entire program year, including 2007, and provided building engineers with a consistent load reduction goal.[17]
- **Demand-Response Enabling Technology.** Participants enrolled in the BEC program have a gateway device installed on their electrical meter that allows them to access the Enjoin system. This gateway device "transmits data to a secure online communication system where members and program managers can access the data to see graphical real time use data - includes alerts, historical analysis, reporting functions. During curtailment events, members can view their target, near-real time usage data (five minute intervals), and performance of the group." This system is superior to the systems used by other demand-response programs, which only allow customers to see their performance the day after the event. The real-time nature of this BEC technology allows participants to invoke additional load reduction protocols in the event that they are not meeting their load reduction commitments.
- **Tenant Education.** The BEC program offers educational classes for building occupants to help them identify actions they can take to assist in the building's efforts to reduce the overall load. This is a particularly important tool for hard-to-reach commercial customers that must manage a wide variety of tenant needs.

3.1.4 BEC Guidance on Demand-Response Actions and Curtailable Load

All customers that sign up for the BEC program are offered a technical site assessment to identify load reduction actions (protocols) that can be taken and to determine a realistic level load that can be shed during BEC events. These site assessments are administered by ASW Engineering and, while not mandatory, are highly recommended and typically accepted. The Energy Coalition has found that the standard audits offered by PG&E (the audits offered to PG&E non-residential customers but not associated with any DR program) are generally not detailed enough to provide a customer with specific load curtailment actions they can take to participate in a demand-response program event.

The ASW Engineering site assessment offered as part of the BEC Program focuses on four main areas of load reduction potential. These areas include the central plant (which includes

[17] As mentioned in Section 2.1.2, the constant firm service level baseline is no longer used starting with the 2008 program year, per CPUC Resolution E-4163.

all chillers and other cooling equipment), any additional pumps or motors in the building, lighting systems, and other miscellaneous areas such as pools and/or fountains. The outcome of the site assessment is a peak-day load reduction plan that the building can follow to achieve their desired load reduction.

BEC program staff report that participants who have received a BEC site assessment take different actions on BEC event days than those who have not received an audit. These audits give the participants a good understanding of the real energy savings resulting from each load reduction protocol (such as resetting the chiller water temperature, turning off a chiller in afternoon, using lower speeds on motors with variable speed drives (VSD), and cycling fans and/or other equipment).

ASW engineers work with the BEC participants to enable additional load reduction protocols as customers become increasingly experienced with taking curtailment actions and, in some cases, start implementing these actions on days that are not BEC event days. BEC staff estimated that approximately 10 to 15% of the programs' participants have dropped out of the program because they have begun invoking these load reduction protocols so regularly (without the program incentives) that they no longer have additional load to drop on event days.

3.2 Process Evaluation of the 2005-07 Special Projects Group

Itron carried out two specific activities to evaluate the Special Projects Group (SPG). The team first reviewed the scope of work[18] between PG&E and The Energy Coalition that describes the purpose of the SPG and then it critically examined the recommendations and findings made by the SPG in its first report deliverable. The SPG was created by PG&E in order to produce two reports. The first of these reports was completed in March 2008 and the second has yet to be released.[19] A review of the first report is provided in this process evaluation of the SPG.

In addition to the scope of work and the SPG deliverables, Itron had planned to conduct a key actor interview with John Phillips, former executive director of The Energy Coalition and primary member of the SPG. As mentioned earlier, the interview did not take place due to circumstances outside Itron's control. Based on a recommendation of Mike Cristofani of PG&E, Itron contacted Mark Fleming as a potential interviewee. However, Mr. Fleming felt that he did not have the detailed background information needed regarding the development of the SPG to provide Itron with enough information to support this process evaluation. Since the second report deliverable has yet to be complete and Itron's interview with a

[18] Exhibit A of PG&E Service Contract #4600017251 between PG&E and the Business Energy Coalition.

[19] The second report was scheduled to be issued in the spring of 2008; however, as of the writing of this report in August 2008, it has not been issued.

member of the SPG never took place, the process evaluation of the Special Projects Group is limited to an examination of the SPG's objectives as they were stated in the relevant scope of work between PG&E and The Energy Coalition and an evaluation of whether or not the SPG's findings and recommendations from the first report serve to advance PG&E's development of an Integrated Demand-Side Management (ISDM) Alliance.

According to the statement of work, the SPG was designed to produce a broad range of IDSM services within the City and County of San Francisco. Activities of the SPG included the following:

- Development of specific sets of IDSM services with the goal of implementing programs that are at least as cost-effective as PG&E's current demand-side management portfolio for its business and residential customers,
- Creation of a new "outside the box" IDSM model to help make demand-side management a sustainable and profitable way to enhance electric capacity, and
- Development of two report deliverables, the first of which is to describe the best means for integrating energy efficiency and demand response programs into an IDSM alliance and the second, to define the evolution of an IDSM alliance between PG&E, local governments, including but not limited to the City and County of San Francisco.

3.2.1 SPG First Report Findings and SPG Recommendations

The first report developed for PG&E outlines a **transformation process model** that, according to the SPG, will "revolutionize" the way in which PG&E reaches out to its customers regarding the importance of conserving energy. The message of this outreach effort is to make demand response and energy efficiency a number one priority in order to help secure PG&E's energy reserves. Overall, this report provides a number of broad suggestions and concepts to improve reliability of PG&E's energy grid and does not provide concrete ways to implement the changes that it suggests.

The document outlines a model for revolutionizing PG&E's customer outreach in San Francisco. This model attempts to converge top-down and bottom-up strategies on improving the value of new outreach programs to energy customers and PG&E shareholders, hopefully resulting in prioritizing demand response and energy efficiency. A great deal of discussion regarding the design of the model's structure is included in the report, but implementation of this model was only briefly touched upon through examples. The second SPG deliverable is intended to provide more of the concrete details.

Examples of successful strategies, which can be modified and utilized to increase PG&E's outreach capability, include the Community Energy Partnership, PEAK Student Energy Actions, and the San Francisco Business Energy Coalition. The Community Energy

Partnership uses a social entity to motivate and spur end user involvement, whish has resulted in substantial increases in demand response and energy efficiency effectiveness. PEAK is an educational program where students gain the skills to contribute demand response capacity and to reduce energy use in their homes. It has now been accepted by the CPUC and three major IOUs for statewide implementation. The San Francisco Business Energy Coalition developed a model that maximizes sustainable participation and performance through the establishment of a coalition of member businesses. These member businesses are given incentives for each kilowatt of load reduction committed and real-time energy usage tracking and analysis hardware. In addition, member employees are supplied with energy efficiency and demand response education.

In order to achieve increased demand response and energy efficiency, the SPG recommends PG&E put IDSM and the negawatts it provides on an equal footing with supply-side resources. The report recommends that PG&E should revise the valuation criteria used for IDSM programs from purely financial parameters (Total Resource Cost and Rate Impact Measure) to criteria that emphasize a socio-economically responsible portfolio approach. According to the SPG, this will maximize end-user value while keeping the utility financially prosperous. For example, a resource allocation scheme could be developed where percentage goals for deployment of conventional central, conventional distributed, and renewable generation as well as demand response and energy efficiency are allocated. PG&E could also create an incentive infrastructure (using mechanisms like rate-basing and performance incentives) that provides the necessary benefits to each party to ensure enthusiastic and continued participation in the project. While the SPG makes this recommendation, it does not take into account that the state of California and the CPUC determine which valuation criteria can be used for evaluation purposes. PG&E could examine its IDSM program using the suggested criteria, but this would have to be done in addition to what PG&E is mandated to use.

Combining the lessons learned from other successful approaches and incorporating the basis for transforming PG&E, regulation, and end users brings about a process model that will be very useful for PG&E and the City of San Francisco, according to the SPG report. This consists of using a service model to redefine how PG&E will better integrate demand response and energy efficiency, customizing the services to meet the needs of different market segments, providing end users with on-going education, and increasing utility presence. The first step is for each involved party to pledge to contribute to the desired community achievement. The next step would be to use an intensive market-segment-based planning process to determine which segments and locales contain the best opportunities to provide socio-economic end-user value and negawatt potential. A steering committee will generate program concepts and ideas to be provided to market-segment-based working committees and end users for feedback. The final step involves establishing an outreach infrastructure that facilitates the development of Community Energy Partnership-based energy districts and customized program portfolios for the end users in those locales.

The process model framework to transform PG&E's end user outreach capability is currently being developed in San Francisco. The BEC has established a network of 60 member businesses and PG&E has committed to pilot the PEAK curriculum in approximately 15,000 students over the next three years in the San Francisco Unified School District. To achieve comprehensive outreach, however, PG&E must define Community Energy Partnership energy districts. If these were established around schools participating in the PEAK curriculum, outreach efforts can target students and their families providing reinforceable education and energy efficiency service opportunities. City residents will then be linked to the efforts of PG&E through multiple outlets and the city will become saturated with PG&E's outreach messaging.

3.2.2 Itron Findings Regarding the SPG

After a review of the objectives outlined in Exhibit A of PG&E's contract with the BEC and a reading of the first report deliverable, Itron finds that the SPG has taken initial steps to outline a process to transform PG&E's IDSM Alliance, but has yet to provide details on how to make this transformation occur. The theme of the first report is that there is a need for change regarding energy use and the time for this change is immediate, however there are few actionable steps laid out. This may be because the SPG plans to present the evolution of this IDSM Alliance in its second SPG report deliverable, however a draft hasn't been issued to date. Itron therefore cannot make any conclusions regarding whether the SPG has completed its objectives as they were laid out in the scope of work.

This first deliverable from the SPG reads more like a concept paper than a report that provides PG&E with steps for the transformation of an IDSM alliance. Much of the report focuses on how people are central to sustainable transformation regarding energy demand side management and any solution to improved reliability of the grid requires socio-economic solutions. The high level discussion found in this report does provide a few examples of Energy Coalition-operated programs that have been implemented, but the report does not provide evidence about how successful these programs have been. It is therefore difficult to know if the SPG has successfully developed a strategy to improve energy efficiency in PG&E's territory. Itron anticipates that second SGP report deliverable will provide the details and methods PG&E should use to improve its ISDM Alliance, however without it, it is difficult to conclude that the SPG has met its objectives.

4

Impact Evaluation

This section presents summaries of the data used, methodologies, and results for the estimation of impacts for the 2007 BEC Program impact evaluation. This section is broken into the following subsections:

- Data Sources for the 2007 BEC Program Evaluation
- Evaluation Population and 2007 BEC Program Events
- Impact Estimation Methods
  - Representative Day Approach
  - 2007 BEC Program Settlement Method (based on customer average peak demand)
  - Site-Level Participant Econometric Approaches
  - Aggregated Participant Econometric Approaches
- Impact Estimate Results based on above Methods for the 2007 BEC Program
- Comparison of Results Across Methods

The purpose of the impact assessment is to provide independent third-party evaluation-based estimates of the peak load reductions associated with the BEC Program for events occurring during the summer of 2007. The approach taken in this evaluation is to use multiple baseline methods to estimate and illustrate the 2007 impacts. These baseline methods, many of which are currently used in California, are described in detail below. They include alternatives that adjust the baselines based on weather, pre-period usage ratios, and regression analysis at both site-level and aggregate levels.

4.1 Data Sources for the 2007 BEC Program Impact Evaluation

The data requirements for this impact assessment included participant-level hourly loads, hourly weather, account characteristics (such as industry type, etc.), and program event information. The primary sources of these data are three SAS files that PG&E provided to Itron:

- ***BECCUSTS (Customer Data):*** 116 observations, 25 variables containing customer information including customer name, attributes (industry and rate schedule), location, and annual energy and demand summaries.
- ***BECLOAD (Load Data):*** 36,674 observations, 100 variables with 15-minute kW readings by customer name and channel from May 1, 2007 through September 30, 2007.
- ***BECWTHR (Weather Data):*** 3,674 observations, 98 variables with 30-minute temperature and relative humidity readings for 11 weather stations from January 1, 2007 through November 30, 2007.

In addition to these SAS data sets, PG&E provided information on the dates, start and end times, and notification details for all 2007 BEC events (i.e., whether program participants received event notification a day ahead or on the day of an event).

4.2 Evaluation Population and 2007 BEC Program Events

The impact assessment for the BEC Program included all participants who were enrolled in the program for the set of events held in 2007 and had an interval meter installed such that the interval meter data could be provided to the evaluation team.

Table 4-1 provides a summary of the 2007 BEC Program events, including the dates for which the events were called, the amount of notification given (day-ahead or day-of), the time period of the event, the number of hours the event lasted, the number of customers enrolled as of the event date, and the number of customers notified about the event that was to occur (where customer count is tallied by service agreement ID regardless of location). The first event, held on June 20, was a test event and lasted only two hours. The remaining four events were called on the day prior to the event and each lasted five hours; the last three events were called on sequential days. This table also shows that, in 2007, the number of enrolled participants remained steady across the summer.[20]

[20] The counts of enrolled and notified participants are based on the service account identification numbers in the customer and interval data that was provided by PG&E. The number of notified accounts in Table 4-1 excludes two accounts that were notified of the events; however, they were excluded from the analysis conducted for this evaluation since they were missing interval meter data.

Table 4-1: Event Dates and Times for the 2007 BEC Program

Event Date	Notification Type	Event Period	Event Hours	Enrolled Participants	Notified Participants
June 20 2007 (test)	*Day-Ahead*	*1-3pm*	*2*	*100*	*68*
July 5 2007	Day-Ahead	2-7pm	5	111	73
August 29 2007	Day-Ahead	1-6pm	5	115	95
August 30 2007	Day-Ahead	1-6pm	5	115	98
August 31 2007	Day-Ahead	1-6pm	5	115	98

4.3 Impact Estimation Methods

Econometric modeling is the primary method for evaluating the ex post impacts associated with the 2007 BEC Program. Representative Day baselines and BEC baseline methods are also examined in this evaluation because they have played, or will continue to play, an important role in the financial settlement process for the program. The first subsection summarizes the aggregate econometric models that were developed to estimate impacts based on a series of weather, time, and calendar variables. This is followed by a section that explains the representative day approach, which requires calculating baselines for each event based on a series of recent “similar” days[21] and, finally, an explanation of the 2007 BEC Program settlement method (based on 2007 average peak demand estimates).

4.3.1 Aggregated Participant Econometric Approaches

The estimation of BEC ex post impacts involved a series of regression models based on the aggregated participant load. Similar to Itron’s evaluation of the BEC Program completed for program years 2005 and 2006, the econometric models developed for this evaluation were carried out as an ex post analysis of the total program impacts. By conducting a regression analysis after the fact, all salient pre- and post-event non-holiday, non-weekend weather and participant interval meter data are available for the analysis, thus improving the quality of the impact estimates. Another benefit of this form of analysis is that it can be used to control the effects of independent factors (such as weather and day-type) that may or may not affect the energy consumption of the BEC Program participants. Controlling these factors helps ensure that any changes in load that would have occurred outside of the program, both increases and decreases, are not attributed to the program.

Conducting a post-program evaluation of impacts for the BEC Program also provides an opportunity to compare impacts estimated through multivariate analysis to those calculated

[21] Similar days exclude weekends, holidays, and any additional days during which a customer was paid to curtail their load.

by taking differences in actual load and alternative baselines on event days. As described earlier, these differences are simplified calculations used by program managers to calculate real-time estimates, often for program settlement purposes. The baseline that generates impact estimates most similar to those based on regression analysis helps guide program managers in their choice of a baseline for real-time analysis. Providing ex post feedback on the performance of alternative baselines, based on regression analysis, is an important function of demand response program impact evaluation.

The aggregated participant econometric models estimated impacts for all five BEC events in 2007, including the June 20 test event, based on the participants that were officially notified for each event. Note that some of the participant accounts had insufficient data to be included in the modeling, so the number of enrolled and notified accounts *after* data attrition (e.g. the number of customers actually used in the econometric analysis) are presented in Table 4-2.

Table 4-2: Number of Enrolled and Notified BEC Customers Used for Aggregate Regression Models

Event Date	Enrolled	Notified
06/20/07	98	66
07/05/07	108	72
08/29/07	109	92
08/30/07	109	94
08/31/07	109	94

A linear regression model was employed for this group of customers to estimate the ex post impacts. These models incorporated autoregressive error correction to account for the time-series nature of the data.[22] The specification for the hourly demand model was as follows:

$$kW_c = a_c + \beta_c^{Wknd} * Wknd + \beta_c^{Hol} * Hol + \sum_{m=May}^{Sept} (\beta_c^m * m) + \sum_{i=1}^{24} (\beta_{c,t}^{HR} * HR_t)$$
$$+ \sum_{i=1}^{24} (\beta_{c,t}^{HRTemp} * HR_t \times Temp_t) + \sum_{i=1}^{24} (\beta_{c,t}^{HREvntTemp} * HR_t \times Evnt * Temp_t) + e_{c,t}$$

[22] For additional information about the inclusion of autoregressive errors to correct for serial autocorrelation, see Kennedy, P. *A Guide to Econometrics*, 3rd Edition, Boston: MIT Press, 1992.

where:

Variable	Meaning	Notes
α	Intercept	
kW	Average hourly kW	
$Wknd$	Binary weekend flag	Equals 1 if day is Saturday or Sunday, 0 otherwise
Hol	Binary holiday flag	Equals 1 if day is a holiday, 0 otherwise
m	Set of monthly dummies for the months of May through September, one of which is dropped to avoid perfect multicollinearity	Actual monthly dummies in model are dependent on the range of dates for the cell being modeled
HR_t	Vector of hourly dummies, where t is the hour of the day	Captures non-temperature related changes in energy use associated with operating schedules.
$HR_t xTemp_t$	Vector of hourly dummies crossed with temperature	Captures hour-specific changes in consumption associated with temperature.
$HR_t vntxTemp_t$	Vector of individual event-day hourly dummies crossed with the temperature	Captures the hourly impact of event-day related changes in energy consumption.

In addition to the variables used in the initial specification, Durbin-Watson tests were used to test for serial correlation and all the models included autoregressive (AR) terms to correct the initial parameter estimates. These models predict the actual load of all the days used in the analysis, including the event days. To capture the effect of BEC events, the models include a series of hourly event day-specific variables. These variables, which cross a binary indicator with the hourly temperature, cover the hours from 11 a.m. to 8 p.m. to capture any pre-cooling or post-event spikes. Using the model parameters associated with the event variables to remove the effect associated with events from the predicted load produces an estimate of what the consumption would have been in the absence of an event. This series is used as the reference, or “baseline” load. The program impacts are calculated by subtracting the actual consumption on event days from the corresponding reference load.

There are hundreds of parameter estimates and statistics associated with these models, which are presented in the appendices. In terms of the overall model fit, the R^2 was used as a measure of model fit and was at least 0.99 for all of the models.

4.3.2 Representative Day Baselines

Because representative day baselines are of great importance to the financial settlement process of demand response programs, Itron examines them here. Although the DR Protocols do not favor using a representative day approach for ex post evaluations, it is frequently used for DR program settlement (and starting in 2008 will be used for BEC Program settlement), and thus provides an opportunity to compare settlement impact estimates to econometric regression estimates.

The representative day approach uses the average load of some combination of the days preceding the event day to estimate what the load on an event day would have been had there been no curtailment activities. These baselines are estimated for each individual site. Once the hourly baselines have been computed for all program participants for each of the event days, hourly event impacts can then be calculated as the difference between the baseline and the actual load for each hour of the event day. The overall program impact for a given event hour is then simply the sum of the hourly differences across the program participants:

$$Difference_t = \sum_n \left(k\hat{W}_{n,t} - kW_{n,t} \right)$$

where

$Difference_t$	=	Difference between the estimated baseline load and the actual load at time t,
$k\hat{W}_{n,t}$	=	Estimated baseline load of customer n at time t, and
$kW_{n,t}$	=	Actual load of customer n at time t.

This summation used to calculate program impacts for the 2007 BEC Program includes all differences (both positive and negative) that exist between the baseline and the event day for all customers. The advantage of this strategy is that, assuming the baseline is unbiased, the small positive and negative differences (that are not necessarily attributable to the program) tend to cancel each other out.

This study included the calculation of six different types of *representative day* baselines, beginning with the straightforward 3-Day and 10-Day versions, which are defined as follows.

3-Day

The current baseline methodology being used for program settlement and reporting at PG&E for two of the primary DR programs (Critical Peak Pricing [CPP] and Demand Bidding Program [DBP]) is referred to as the ***3-Day baseline***. This baseline is calculated by first selecting a series of days that represent the most recent 10 similar days that occurred prior to the event day. Similar days exclude weekends, holidays, and any additional days during which a customer was paid to curtail their load. From this series of 10 similar days, the three days with the highest overall energy consumption during the curtailment hours were selected and the load for each hour of these three days was averaged (by hour) to calculate an hourly 3-Day baseline estimate.

10-Day

An alternative baseline methodology used to calculate program settlement impacts for the BEC program was the ***10-Day baseline***. This baseline is similar to the 3-Day baseline in that it also selects a series of the last 10 similar days. However, as opposed to selecting the three highest days from the last 10 days, this approach calculates the 10-Day baseline for each hour by averaging the hourly load over all of the last 10 similar days.

Because these two baselines are the foundation for all of the baselines incorporated into this study, it is worth the effort to consider the differences between them. By definition, the 3-Day baseline will be higher than the 10-Day. Nevertheless, the difference between these baselines depends considerably on a site's patterns of consumption. For sites that have very consistent levels of consumption, there will be little difference between the two baselines. For sites that have highly variable patterns of consumption – perhaps due to high weather sensitivity – these two baselines will produce considerably different results. Good illustrations of these are presented in Figure 4-1 and Figure 4-2, which show the 3-Day and 10-Day baselines along with their contributing loads for two separate sites for the event on August 29, 2007.

Figure 4-1 shows the baselines for a site with higher levels of load variability. The three days that contribute to the 3-Day baseline are all similar, whereas the 10-Day baseline includes the same days in addition to a number of days with much lower consumption, resulting in a considerably lower baseline, particularly for the first three hours of the event window (the dashed blue square). Clearly, the choice of baseline for calculating impacts for this site will produce highly different results. Note that while the hours outside the event window are helpful to see the patterns of consumption, they do not play a role in selecting the days for the 3-Day baseline or for calculating impacts.

Figure 4-1: 3-Day and 10-Day Baselines for Site with High Load Variability

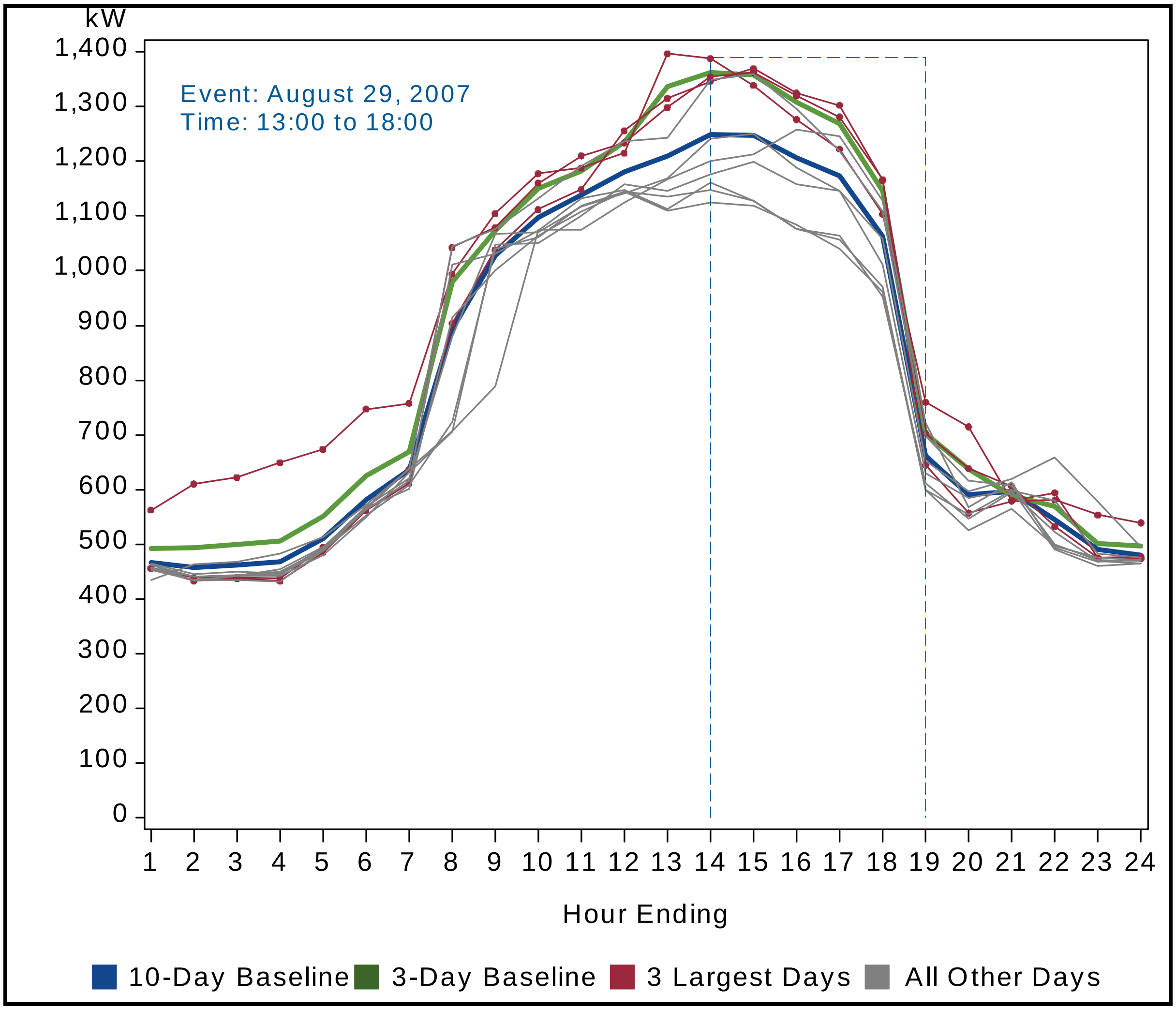
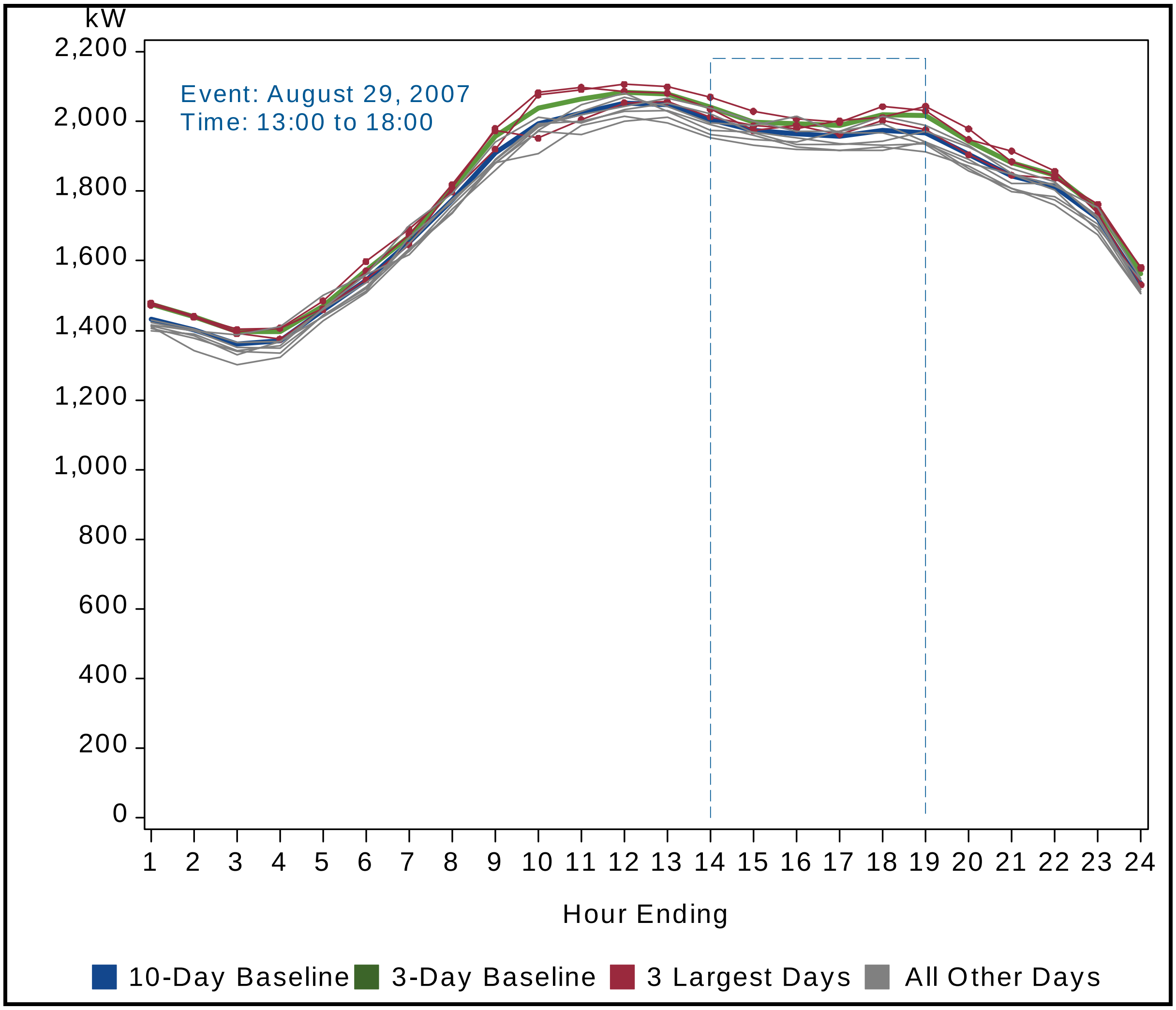


Figure 4-2 presents a considerably different case, where the load varies very little over the 10 days that contribute to the baselines. As always, the 3-Day is higher, but in the case of this site, the differences are small due to the lack of variability, so the selection of the baseline will not be as critical in determining the impact of an event.

Figure 4-2: 3-Day and 10-Day Baselines for Site with Low Load Variability



As the above illustration demonstrates, the 3-Day and 10-Day baselines can result in very different estimates of consumption. Consequently, this study also included alternative baselines that attempt to adjust the 3-Day and 10-Day baselines up or down using recent information about a participant's level of consumption. There are two types of these adjustments: one based on consumption during the four hours prior to the event (on the event day), and the other based on consumption on the previous similar day to the event day. These morning-of and previous-day adjustments are described below in relation to either the 3-Day or 10-Day baseline and are applied in a similar manner.

Morning-Of Adjustment

The Morning-Of Adjustment is a scalar adjustment calculated as the ratio of the average of the actual load during the four hours prior to the start of the event divided by the average of the predicted load (either 3-Day or 10-Day baseline) during those same four hours:

$$Morning\text{ - }Of\ \ Adjustment = \frac{Average\ Actual\ Load\ \ for\ Four\ Hours\ Prior\ to\ Event}{Average\ Predicted\ Load\ \ for\ Four\ Hours\ Prior\ to\ Event}$$

This scalar adjustment is used to calibrate the 3-Day and 10-Day baselines to the customer's level of operation on the actual day of the event. The 3-Day Morning-Of Adjusted and 10-Day Morning-Of Adjusted baselines are calculated as follows:

$$Morning\ Of\ \ Adjusted\ Baseline\,(3\ \mathrm{Day\ or\ 10\ Day}) = Scalar\ \ Adjustment \times Baseline\,(3\ \mathrm{Day\ or\ 10\ Day})$$

The Morning-Of Adjusted baselines that are used to calculate impacts are still based on actual event hours, while the scalar adjustment is used to reflect how similar the average peak load is during the hours prior to the event on the event day. The scalar adjustment is capped in such a way that it can never take a value greater than 1.2 or less than 0.8, so that it can never increase or decrease the baseline to an unrealistic level.

Previous-Day Adjustment

The Previous-Day Adjustment is also a scalar adjustment based on a ratio of actual to predicted consumption, but in this case, it considers consumption on the most recent applicable day prior to the event. The scalar adjustment is calculated based on a series of calibration hours and is computed as the ratio of the average load over the three calibration hours to the average load for the same three hours from the most recent applicable day prior to the event. The calibration hours used for this analysis were the hours from 12 p.m. until 3 p.m. on the most recent similar day.[23]

$$Previous\text{ - }Day\ Adjustment = \frac{Average\ Load\ \ during\ Calibration\ Hours}{Average\ Load\ \ during\ same\ hours\ Baseline\,(3\text{ - }\mathrm{Day\ or\ 10}\text{ - }\mathrm{Day})}$$

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[23] Average load during these calibration hours was used in an effort to represent load during an event pre-notification period that is similar enough to load on the event day had one not been called. For further information regarding the selection of these calibration hours, refer to Section 6 of Quantum Consulting and Summit Blue Consulting. *Evaluation of 2005 Statewide Large Nonresidential Day-Ahead and Reliability Demand Response Programs Final Report*. Prepared for Southern California Edison Company and Working Group 2 Measurement and Evaluation Committee. April 2006.

The 3-Day and 10-Day Previous-Day Adjusted Baselines are calculated in the following manner:

$$Previous\text{ - }Day\ Adjusted\ Baseline = Scalar\ Adjustment \times Baseline(3\text{ - }Day\ or\ 10\text{ - }Day)$$

As with the morning-of adjustment, the scalar is also bounded at 0.8 and 1.2.

4.3.3 2007 BEC Program Settlement Method

The impact calculation method used by the BEC Program (as approved for the 2007 BEC Program by the CPUC) is based on each customer's pre-determined average monthly peak demand for 2007. Using this approach, a customer's load reduction for a given event is simply the difference between their average monthly peak demand and their actual hourly load during the event.

4.3.4 Site-Level Participant Econometric Approaches

This study also included the estimation of site-level econometric baselines for each event day. Although econometric baselines cannot be used for settlement, they generally provide a better estimate of what consumption would have been in the absence of an event, and therefore will provide better estimates of program impacts.

This study included aggregate econometric models that also serve this purpose, which are discussed in the next section, so these site-level models, which were less rigorous, might seem redundant. However, an additional benefit of the site-level econometric models is that they provide a means of assessing the various representative day baselines. That is, by assuming that the econometric baselines represent the closest approximation of reality, we can see which of the representative day baselines provides the most accurate estimate of program impacts.

The econometric baselines were based on a separate model for each hour of the day and the data used for estimation excluded all weekends, holidays, and event days. Rather than customize the model specification for each individual customer, the same basic specification was applied to all hours and all sites for model consumption as a function of temperature and calendar variables:

$$kW = \alpha + \beta_0 \times Day + \beta_1 \times Month + \beta_2 \times Temp + \beta_3 \times LagR$$

Where:

kW	=	Hourly kW
α	=	Intercept

Day	=	Vector of daily dummy variables; Monday through Thursday
Month	=	Vector of monthly dummy variables; May through August
Temp	=	Hourly temperature
LagR	=	Vector of lagged residuals; three lags included.

The model included three lagged residuals, which called for two stages to the modeling. Inclusion of lagged residuals corrects for potential autocorrelation[24], which is often found in time series regression models. First, an initial model was estimated and the residuals were calculated based on the predicted and actual kW. In the second stage, the residuals for the three previous observations were added to the model specifications and the final models were estimated.

These models were estimated for all accounts where there were sufficient data available. This means that for the 101 participants that were notified for at least one event, there were a total of 2,424 different models estimated. Given this quantity, it is not practical to provide detailed results here, but Table 4-3 shows the range (by percentile) of adjusted R^2 statistics that resulted from the regression models. While these results show variation in the performance of the models, the R^2 values are notably higher during hours 14 to 20, which coincide with the events.

[24] Serial correlation is a violation of the classical econometric assumption that disturbances are not correlated with other disturbances. Primary problems with autocorrelation are estimations of inefficient parameters when ordinary least squares regressions are used and incorrectly calculated standard errors.

Table 4-3: Adjusted R^2 Percentiles by Hour for Site-Level Econometric Models

Hour Ending	5th Percentile	25th Percentile	50th Percentile	75th Percentile	95th Percentile
1	0.06	0.33	0.55	0.69	0.79
2	0.12	0.34	0.48	0.61	0.77
3	0.09	0.29	0.45	0.60	0.72
4	0.04	0.29	0.40	0.59	0.75
5	0.04	0.27	0.41	0.59	0.74
6	0.14	0.27	0.45	0.58	0.78
7	0.16	0.36	0.48	0.59	0.70
8	0.15	0.35	0.52	0.61	0.76
9	0.15	0.35	0.55	0.66	0.72
10	0.17	0.42	0.56	0.69	0.76
11	0.22	0.41	0.56	0.68	0.76
12	0.20	0.43	0.58	0.69	0.77
13	0.16	0.47	0.59	0.71	0.82
14	***0.20***	***0.49***	***0.61***	***0.74***	***0.84***
15	***0.17***	***0.39***	***0.56***	***0.67***	***0.80***
16	***0.22***	***0.49***	***0.59***	***0.72***	***0.81***
17	***0.27***	***0.51***	***0.62***	***0.72***	***0.82***
18	***0.22***	***0.44***	***0.57***	***0.72***	***0.83***
19	***0.13***	***0.32***	***0.47***	***0.63***	***0.83***
20	***0.10***	***0.29***	***0.43***	***0.58***	***0.81***
21	0.10	0.29	0.44	0.57	0.76
22	0.07	0.29	0.43	0.60	0.75
23	0.09	0.28	0.43	0.57	0.76
24	0.07	0.26	0.45	0.60	0.76

4.4 Impact Evaluation Results

This section of the report presents the estimated program impacts resulting from the representative day, econometric regression modeling, and 2007 BEC Program settlement methodologies. These estimates are presented by individual event, event hour, and overall for the program year.

4.4.1 Aggregated Participant Econometric Impact Estimates

This subsection presents the results of the regression analysis used to estimate the ex post impacts of the BEC Program for 2007. As stated earlier, econometric estimation allows for the control of changes in energy consumption that are not program related and that occur during the period over which the BEC Program operates. Because these estimates are calculated post-event, it allows for a more refined estimate of program impacts.

The modeling efforts for this study produced hourly ex post impact estimates for all five of the BEC program's 2007 events, which are provided in Appendix F in a format consistent with the protocols. The summary of the ex post impacts from the aggregate models presented in Table 4-4 shows average hourly impacts that range from 0.7 MW for the August 31 event to 12.1 MW for the August 29.

Table 4-4: Aggregate Econometric Model Ex Post Impacts

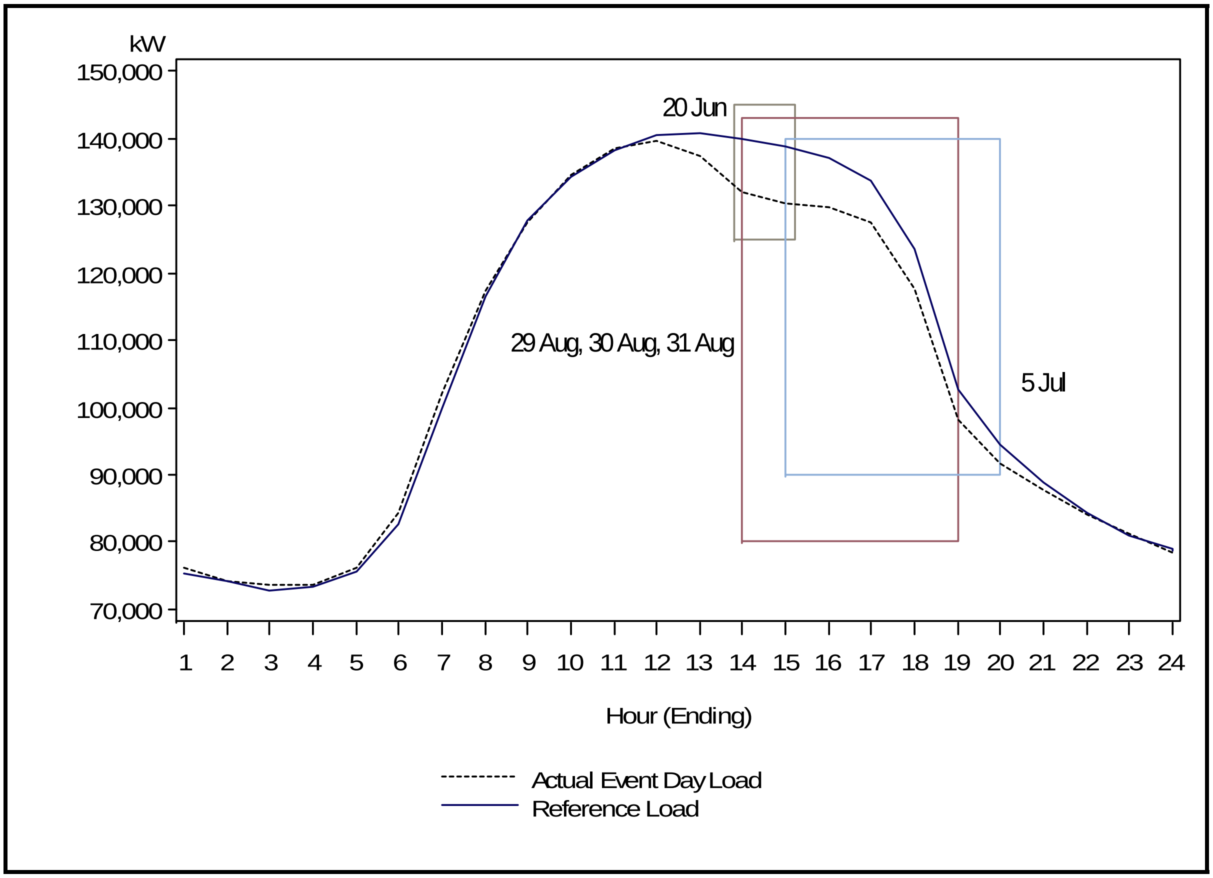
Event Day	Event Start Hour	Event End Hour	Event Hours	Notified Accounts Modeled	Mean Hourly Impact (MW)	Per Participant Impact (MW)	Impact as Percent of Baseline
20-Jun-07	13	15	2	66	3.2	0.1	3.0%
5-Jul-07	14	19	5	72	10.7	0.74	9.3%
29-Aug-07	13	18	5	92	12.1	0.66	7.8%
30-Aug-07	13	18	5	94	11.2	0.59	7.2%
31-Aug-07	13	18	5	94	0.7	0.03	0.5%
All Event Days				86	8.1	0.43	5.9%

Given the variation in impacts shown in Table 4-4, there are a number of points worthy of discussion. The comparatively low impacts for the first day are not surprising, given that it was a test and the average temperature was only 64 degrees, but there are also clear differences among the other days. The per-participant impacts vary considerably by the event days. While the smaller per-participant impact on June 20 is likely associated with lower temperatures on that day (see Table 4-5), there is also the possibility that the composition of participants included or excluded a large or small account relative to the other days.

The most interesting of these results is the very small impacts associated with the August 31 event, which stand in stark contrast to the three other non-test event days. Several possible explanations make this result not entirely surprising. For one, this event was the third in a row and fell on the Friday before a holiday weekend. In addition, the average temperature during the event hours was significantly lower than those of the previous two days, which were also events. What is not clear is whether this pattern of diminishing impacts would necessarily occur on three successive events had they occurred earlier in the week and under similar weather conditions. However, it is clear that there is a decrease between the first and second event days when the temperature is approximately the same. The absence of any load reduction on the third successive day may have been the combination of the factors already mentioned.

Figure 4-3 illustrates the reference and estimated event day loads for the average 2007 event day. The event hours for the different event days are shown with boxes, denoting which event hours overlapped for all event days.

Figure 4-3: Reference and Actual Load for Average Event Day



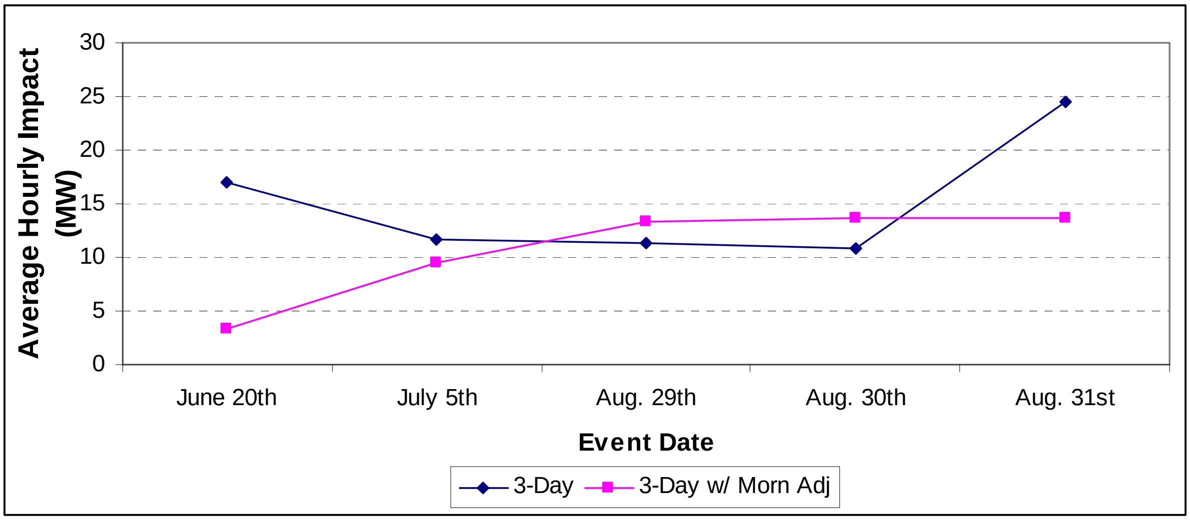
4.4.2 Representative Day Impact Estimates

This section presents estimates of peak load reductions for the BEC Program resulting from the representative day methods. Although representative day impacts were calculated for all six of the methods presented earlier in this chapter, the emphasis of the results in this section is almost exclusively on the 3-Day and the 3-Day Morning Adjusted baselines. These two methods are presented here since the 3-Day baseline is what is used by other PG&E Demand Response Programs (such as CPP and DBP) and the 3-Day with Morning Adjustment baseline is what will be used for the BEC Program in PY2008. The final impact estimates include all differences between the baseline and actual event day load (both positive and negative impacts).

Average Hourly Program Impacts

To ascertain how the BEC program performed throughout the summer of 2007 we calculated the average hourly program impact across all BEC participants who were enrolled and notified for each of the events. Figure 4-4 presents the average hourly program impacts for each event based on the 3-Day and 3-Day with Morning Adjustment baselines (expressed as the total MW reduction). As this figure shows, the average hourly impacts for the 2007 BEC events fluctuated between 10 and 25 MW based on the 3-Day baseline and between 3 and 14 MW based on the 3-Day with Morning Adjustment. The average impact across the five events based on the 3-Day baseline was 14.7 MW compared to 10.4 MW for the 3-Day with Morning Adjustment.

Figure 4-4: Average Hourly Representative Day Impacts Across 2007 Events



As Figure 4-4 shows, the morning adjustment has the biggest effect on the estimated impacts for the first event (a two-hour test event) and the last event (a Friday event that came directly after two previous events and was nearly 10 degrees cooler than the previous two days). The adjustment in both of these cases changes the estimated impact by nearly 10 MW.

Table 4-5 presents the average peak temperature and humidity for each of the five event days between the hours of 12 – 6 p.m. Comparing the average peak temperature from these event days to the average hourly impacts presented in the figure above shows that on the three days when the average temperature was less than 80 degrees, the Morning-Of Adjustment ratcheted the 3-Day Adjusted baseline down such that the 3-Day unadjusted baseline result estimated higher event day impacts (much higher for the first and last events). However, on the August 29 and 30 events, where the average temperatures soared above 85 degrees, the estimated impacts associated with the 3-Day, Morning Adjusted baseline were higher.

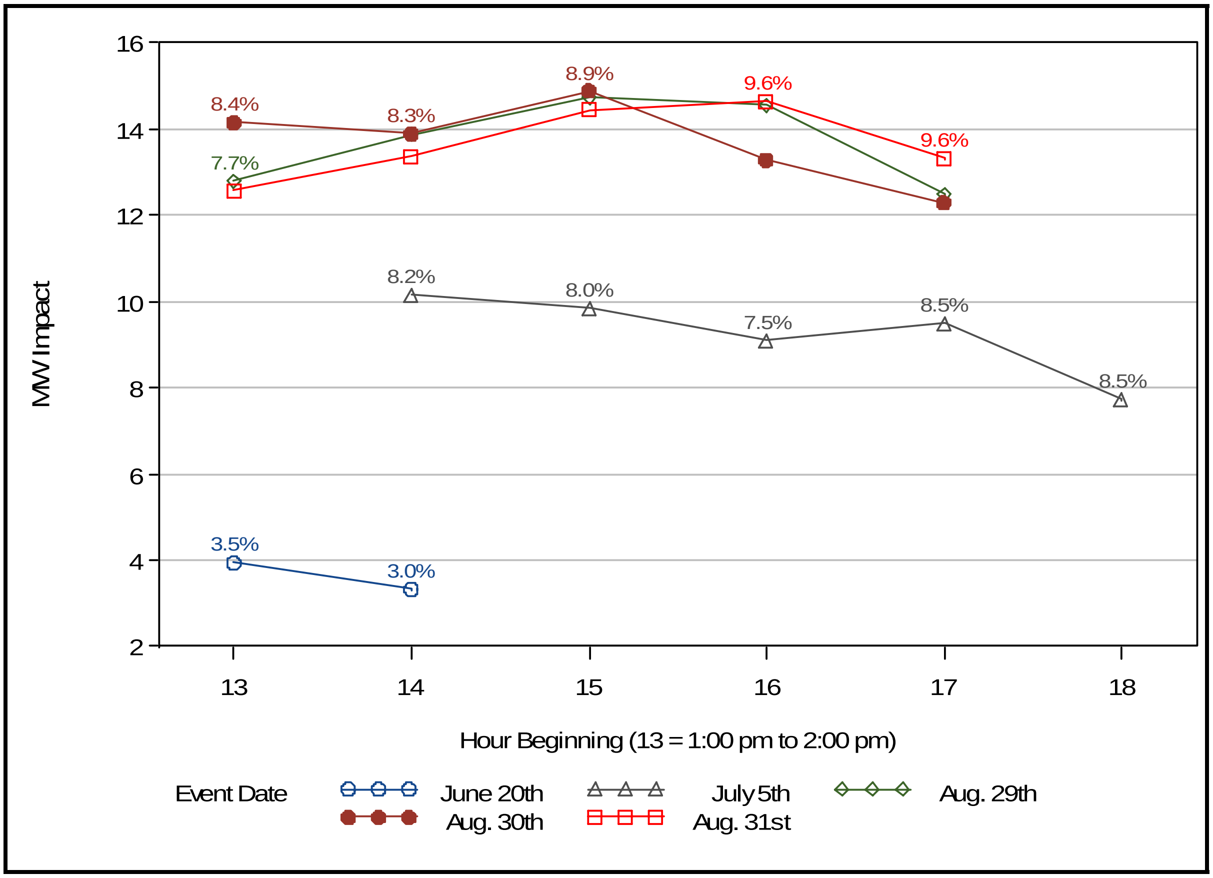
Table 4-5: Average Peak Temperature and Humidity During 2007 BEC Events

Event Date	Average Peak Temp	Average Peak Relative Humidity
06/20/07	66.6	86.7
07/05/07	79.6	84.7
08/29/07	85.7	81.1
08/30/07	86.2	80.3
08/31/07	77.9	84.7

Hourly Program Impacts

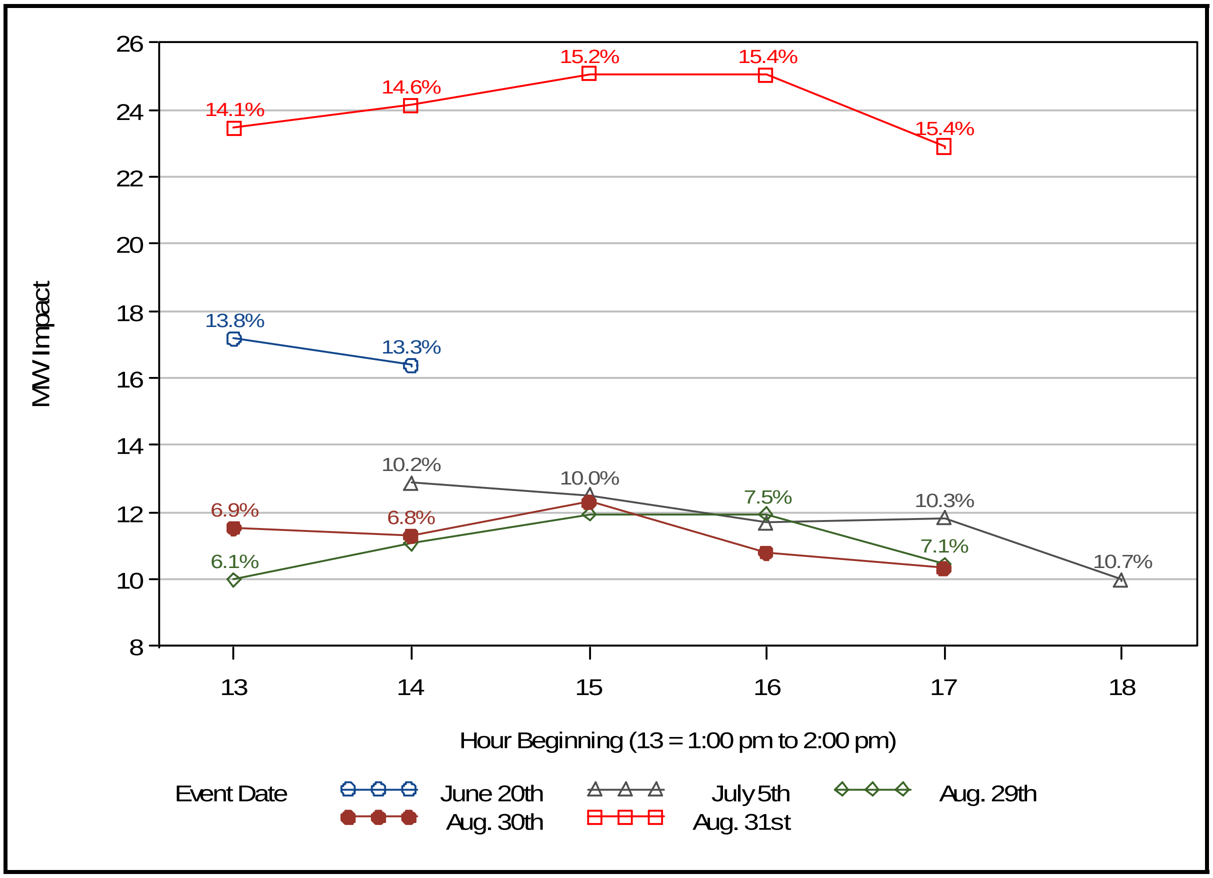
Itron also examined how, on average, the BEC program performed over the course of the event hours. This provides information on whether it takes customers time to curtail their load at the start of an event, and whether or not they are able to maintain their load reductions over the entire event period. Figure 4-5 presents the estimated hourly impacts for each of the BEC events occurring during the summer of 2007, based on the 3-Day Morning Adjusted baseline with the percentage of the baseline reduced shown above the plots points. The figure shows that for three of the four non-test events, the impacts remain consistent over the event hours. The July 5 event has distinctly lower impacts than the three August events, which is due to both the smaller number of participants and the slightly smaller per-participant impact, which is likely associated with the cooler temperatures on that day.

Figure 4-5: Hourly Program Impacts for Each of the 2007 Events, 3-Day Morning Adjusted Baseline



The impacts by event day and hour for the unadjusted 3-Day baseline shown in Figure 4-6 present a different picture. While the impacts remain constant across the event hours, the relative positions of the impacts based on unadjusted baselines are very different. The impacts associated with the August 31 event are nearly double those associated with the morning-adjusted baseline. The actual cause of this discrepancy would require a detailed analysis of the individual participant's loads, but it is worth noting that this event was on a Friday before a holiday weekend. Sites might have had diminished activity due to staff and customers taking an additional day, which resulted in a large downward adjustment for that day. The average temperature was also nearly 10 degrees cooler on this date than on the previous two event days.

Figure 4-6: Hourly Program Impacts for Each of the 2007 Events, 3-Day Baseline



Yearly Program Impacts

Table 4-6 presents a summary of the estimated impacts, percent load reduction, and impact per participant for all 2007 events, along with the average across the program year events. The percent load reduction shown in this table is calculated as the sum of the estimated impacts across all BEC participants who were notified for the event divided by the sum of the estimated load of these participants in the absence of the program (based on the 3-Day and 3-Day Morning Adjusted baseline). As the table shows, the average load reduction of a BEC participant across the event hours was just over 10% based on the 3-Day baseline method and less than 8% based on the 3-Day baseline with the Morning-Of Adjustment.

Table 4-6: Summary of Yearly Program Impacts Based on Rep Day Methods

		3-Day Baseline			3-Day Morning Adj Baseline		
Event Date	**Notified Accounts**	**Estimated Impact**	**Impact per Participant**	**% Load Reduction**	**Estimated Impact**	**Impact per Participant**	**% Load Reduction**
June 20	68	17.0	0.25	13.5%	3.4	0.05	3.3%
July 5	73	11.7	0.16	10.1%	9.5	0.13	8.1%
Aug. 29	95	11.4	0.12	7.0%	13.3	0.14	8.5%
Aug. 30	98	10.8	0.11	7.0%	13.3	0.14	8.4%
Aug. 31	98	24.5	0.25	14.9%	13.7	0.14	9.1%
Average	**.**	**14.8**	**0.17**	**10.4%**	**11.7**	**0.12**	**7.7%**

It is interesting to note that on average, across all notified accounts, the Morning Adjustment for the August 29 and August 30 events increased the estimated average baseline load by a little over 1% (from 1.68 MW to 1.71 MW for the 8/29 event and from 1.65 MW to 1.67 MW for the 8/30 event) which resulted in an approximately 20% increase in the overall estimated impacts for these events (13.3 MW versus 11.4 MW for the 8/29 event and 13.3 MW versus 10.8 MW for the 8/30 event). This is in contrast to the August 31 event for which the Morning Adjustment decreased the estimated average baseline load by roughly 6% (1.54 MW versus 1.65 MW) which resulted in a nearly 50% reduction in the overall estimated impact (13.7 MW versus 24.5 MW).

Distribution of Impacts Across Participants

The distribution of load reductions achieved by BEC participants during the 2007 BEC events was also examined. Table 4-7 presents the percentage of event hours for which BEC participants were able to achieve various levels of demand reduction. The load reduction percent is calculated as the ratio of the estimated load drop divided by the estimated base load using the 3-Day and the 3-Day Morning Adjusted baselines. This exhibit shows that in 2007 participants were able to achieve a 20% reduction in their loads during 17% of the event hours based on the 3-Day baseline method. Using either of the two baseline methods presented here (3-Day or 3-Day Adjusted), participants were only able to reduce their loads by at least 5% for approximately half of the event hours (56% and 46%, respectively).

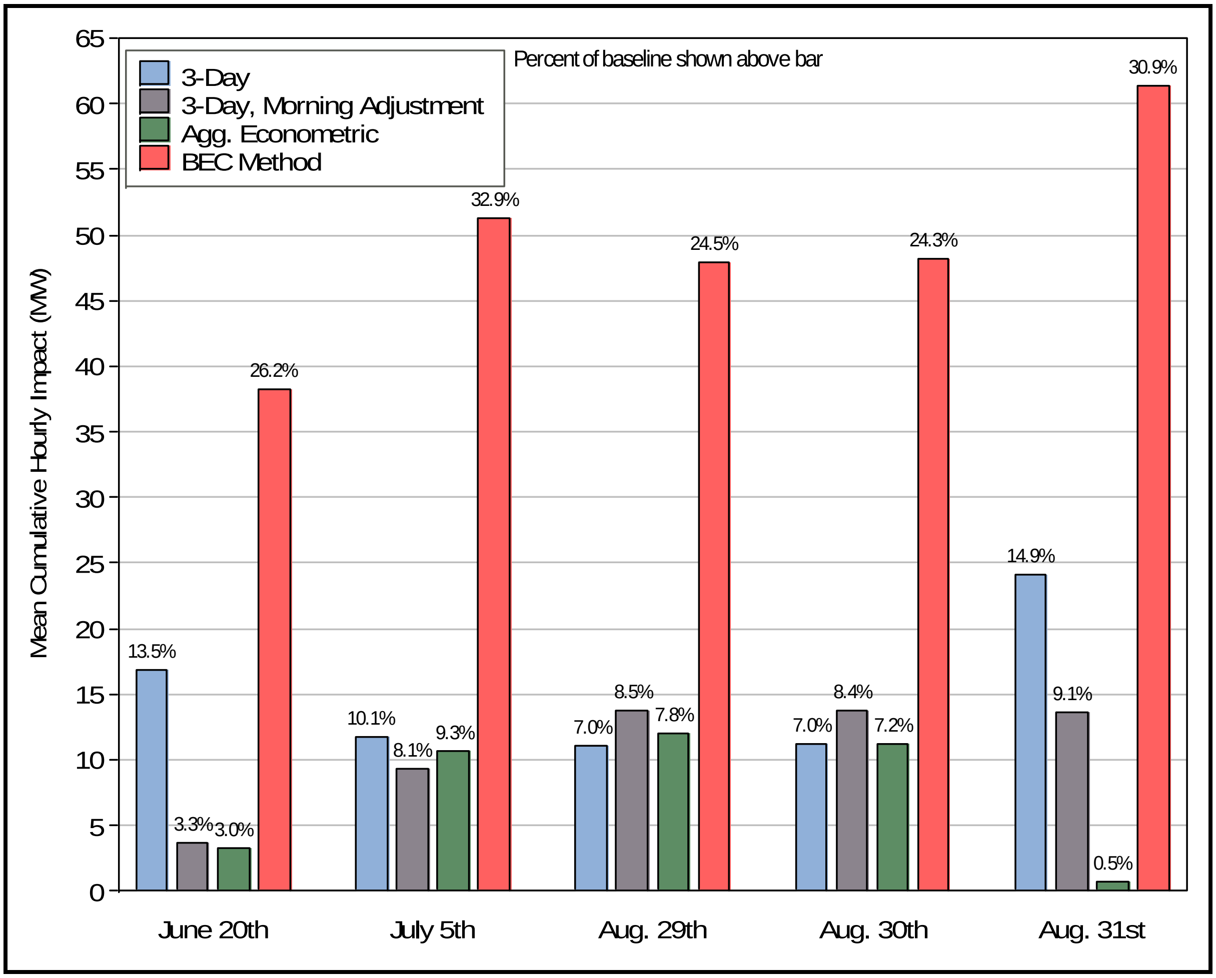
Table 4-7: Distribution of Impacts as a Percent of Load by Baseline and Impact Percent Grouping, All Notified Parts

Load Reduction	Percentage of Participants	
	3-Day	3-Day Adj
5%	56%	46%
10%	37%	28%
20%	17%	12%
40%	5%	5%

4.4.3 2007 Program Settlement Method

As described above, the method used in 2007 by the BEC Program to calculate event impacts was based on the difference between a customer's average peak demand in 2007 and their actual event day load. Figure 4-7 shows the average hourly impacts for the two representative day baselines along with hourly estimated impacts based on the aggregate econometric models and the BEC method.

Figure 4-7: Average Hourly Impacts by Event Date for Notified Participants



As the figure above shows the impacts resulting from the BEC method are always substantially higher than those from the representative day methods (an average of more than three, four, and five times higher than the 3-Day, 3-Day Morning Adjusted, and the aggregate econometric modeling method across the five event days). Table 4-8 shows that the average customer load reduction based on the BEC method reached nearly 33% for the July 5 event, whereas it was calculated to be between 7% and 9% using the two representative day methods.

Table 4-8: Average 2007 Event Day Impacts (in MW) and Percent Load Reductions for all Notified Participants

		3-Day Baseline		3-Day Morning Adjusted Baseline		BEC Peak Reduction	
Event Date	**Notified Accounts**	**Average Load Reduction**	**Average Hourly Impact**	**Average Load Reduction**	**Average Hourly Impact**	**Average Load Reduction**	**Average Hourly Impact**
June 20	68	13.5%	17.0	3.3%	3.4	26.2%	38.1
July 5	73	10.1%	11.7	8.1%	9.5	32.9%	51.8
Aug. 29	95	7.0%	11.4	8.5%	13.3	24.5%	48.5
Aug. 30	98	7.0%	10.8	8.4%	13.3	24.3%	49.0
Aug. 31	98	14.9%	24.5	9.1%	13.7	30.9%	61.7
All Events		10.4%	14.8	7.7%	11.7	27.6%	49.8

Figure 4-8 compares the average cumulative event day load shape across all BEC participants that were notified of an event with the Peak Load and two representative day baselines. As this figure shows the Peak Load looks to be 5 to 10 MW higher than the representative day methods and results in significantly higher impacts in hours 17-19 due to its static nature (i.e., since it is a constant, it does not reflect the daily load shape of the customers enrolled in the BEC Program). This figure also shows that the representative day baselines seem to do a good job in the pre-and post-event hours of simulating the average customer load and the load drop the participating customers make can be clearly detected.

Figure 4-8: Average Cumulative Event Day Load Shapes Versus BEC Method and Representative Day Baselines for all Notified Participants

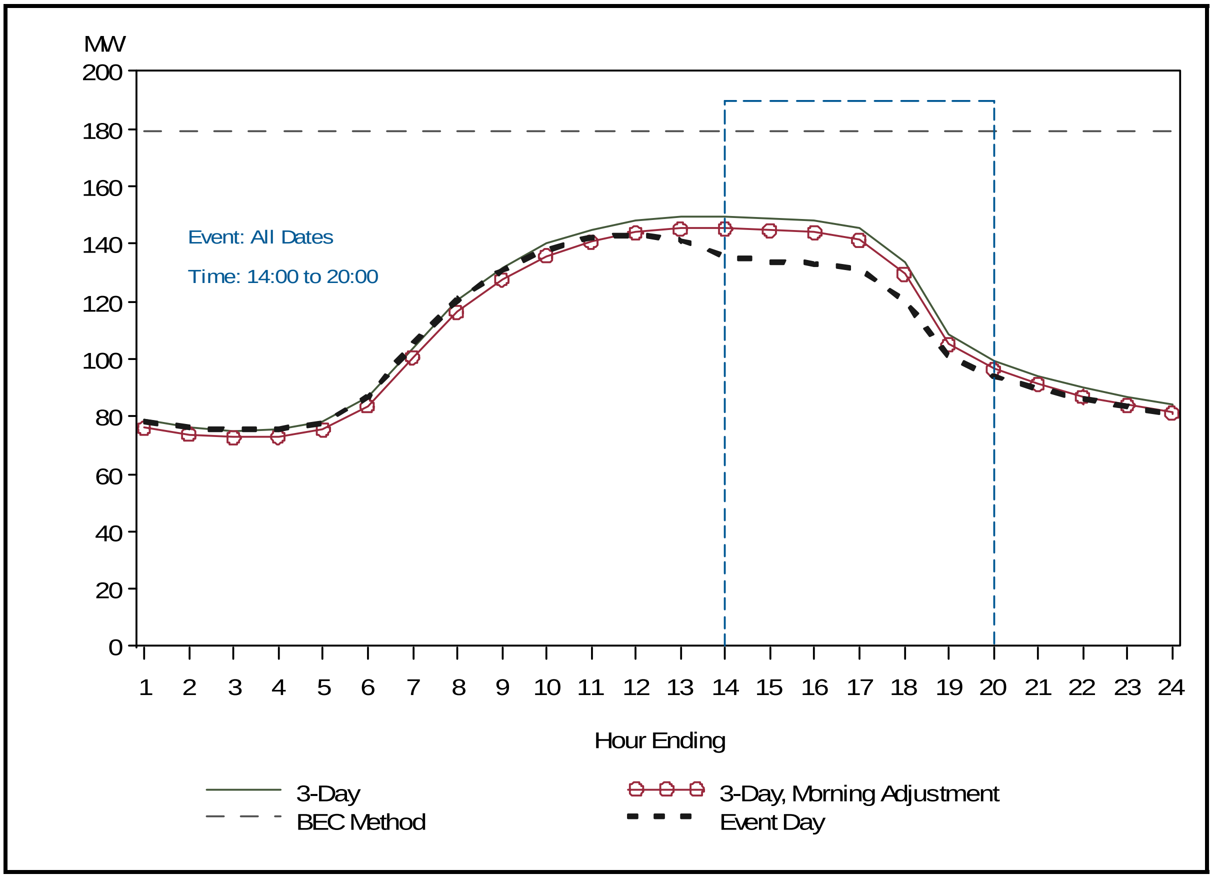
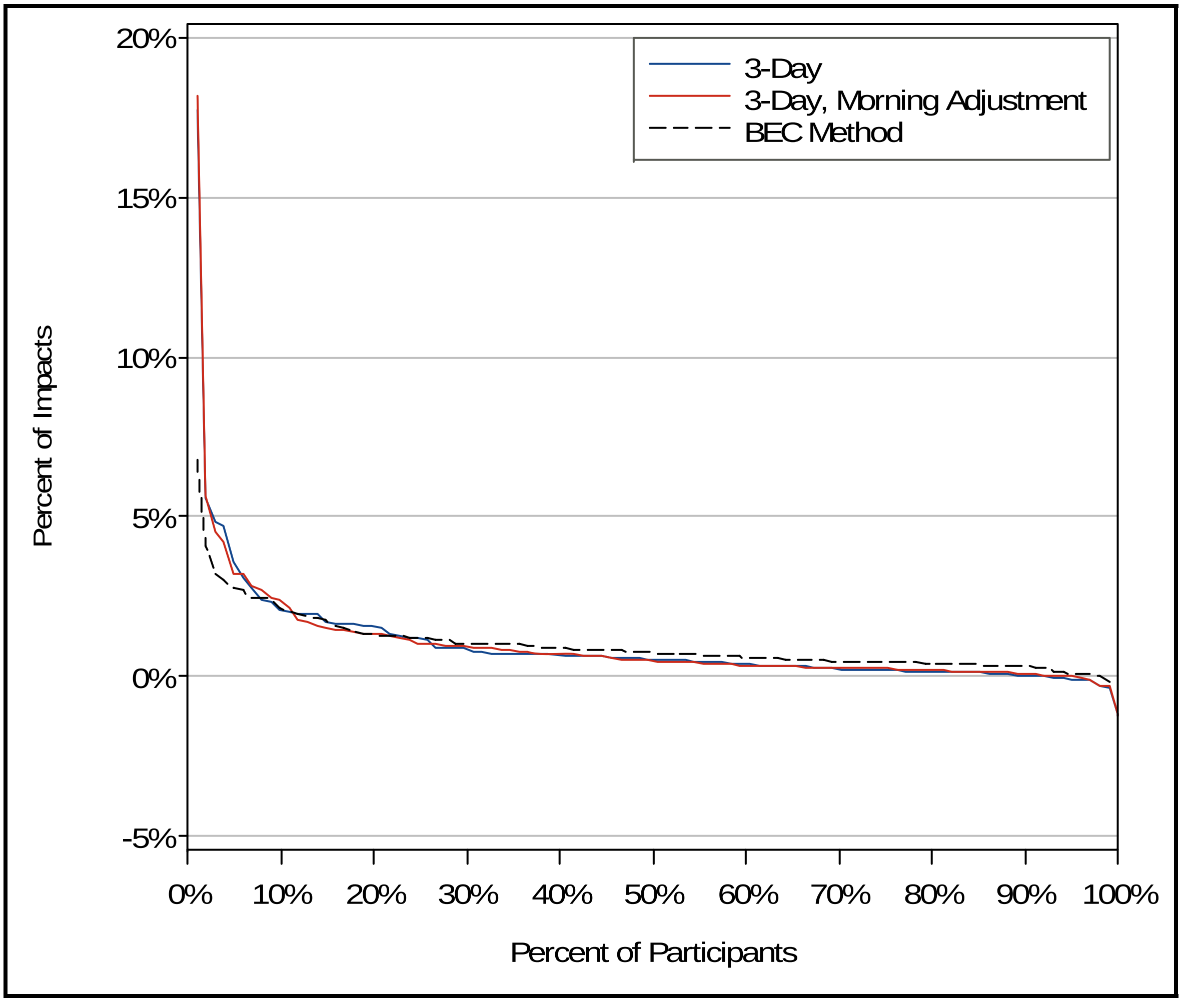


Figure 4-9 shows the distribution of individual participants' contribution to overall program impacts. The variations on the 3-Day baselines vary little from each other, with the top 1% of the participants accounting for around 18% of the impacts (based on average hourly impacts). In contrast, for the BEC impact calculation method, the top 1% of participants account for around 7% of the total impact. This is because the BEC impact method results in positive impacts for nearly every account, so that the share of the total is distributed among many more participants.

Figure 4-9: Distribution of the Percent of BEC Program Impacts Participants Contributed to the 2007 BEC Events



4.4.4 Site-Level Econometric Impact Estimates

This section presents estimates of peak load reductions for the BEC Program resulting from the site-level econometric baselines. These impacts are calculated by subtracting the actual event day load from estimated load based on the econometric models. As shown in Table 4-9, the average hourly impacts for the notified participants that had models range from 3.8 MW for the test event to nearly 12 MW for the event on July 5. Overall, the average hourly impacts represent a reduction in the baseline load of 7.7%.

Table 4-9: Site-Level Econometric Model Impacts

Event Day	Event Start Hour	Event End Hour	Event Hours	Notified Accounts Modeled	Mean Hourly Impact (MW)	Total Impact (MW)	Per Partici-pant Impact (MW)	Impact as Percent of Baseline
20 Jun 2007	13	15	2	68	3.8	7.6	0.11	3.4%
5 Jul 2007	14	19	5	73	11.9	59.6	0.82	10.2%
29 Aug 2007	13	18	5	95	11.6	57.8	0.61	7.3%
30 Aug 2007	13	18	5	98	11.7	58.3	0.60	7.2%
31 Aug 2007	13	18	5	98	11.7	58.3	0.59	7.8%
All Event Days				89	11.0	53.9	0.56	7.7%

The site-level model impacts are based on the sum of the separate hourly models. These models exclude all weekends, holidays, and event days, so even though they include day type indicator variables, they produce a much more generic estimate of load. This means that they do not capture the effects of the two event days that led up to the August 31 event and this makes the impact estimate for that date questionable. The aggregate model used more of a time series approach that includes all days and modeled every event on its own set of indicator variables. In general, the site level models did a poor job of baseline predictions for that event day.

In addition to providing an additional estimate of impacts, the site-level econometric baselines offer a reasonable means to assess how well the representative-day baselines portray customer loads in the absence of an actual event, allowing them to be compared to one another to provide some indication of which ones offer the most accurate estimates of program impacts. This study relied on two measures to assess the quality of the representative day baselines. The first measure is the percentage error (*PE*), which is calculated as follows:

$$PE_i = \left(Econ\_kW_i - Base\_kW_i\right) / Econ\_kW_i$$

Where

PE_i = the percentage error in hour i
$Econ\_kW_i$ = the site-level econometric baseline in hour i
$Base\_kW_i$ = the representative baseline in hour i

This measure shows how much a representative-day baseline deviates from the econometric estimate as a percentage of the econometric baseline. The problem with the with *PE* is that negative and positive differences will balance each other out, so a small *PE* might indicate a good baseline or it might simply indicate that there is balance between the negative and positive differences. The value of the *PE* will show, on average, whether a baseline is resulting in over- or under-estimation of customer loads.

As a better means of assessing baseline accuracy, the second measure is the absolute percentage error (*APE*), which is calculated as follows:

$$APE_i = \left| \left(Econ\_kW_i - Base\_kW_i \right) / Econ\_kW_i \right|$$

Where

APE_i	=	the absolute percentage error in hour *i* and
$Econ\_kW_i$	=	The site-level econometric baseline in hour *i* and
$Base\_kW_i$	=	the representative baseline in hour *i*

The *APE* does not allow negative and positive differences to offset each other. Its values will always be positive and therefore provides a more meaningful estimate of how far a representative-day baseline deviates from the econometrically derived estimate. Both the *PE* and *APE* are generated for every account, event day, and hour and can be summarized across different dimensions (event days, hours, etc.) in terms of the mean percentage error (MPE) and mean absolute percentage error (MAPE). Note that the *PE* and *APE* are used in lieu of the actual deviations because they allow for comparisons across dimensions that might have significantly different levels of consumption. In such cases, the absolute deviation would make comparisons less meaningful.

These *PE* and *APE* were calculated for the all notified BEC participants that had sufficient data to estimate an econometric model. The MPE and MAPE across all participants and event hours are presented for each event day in Table 4-10. The MPE provides insight into the tendency of a baseline to over- or under-estimate, with negative values indicating that a particular baseline overestimates load, producing larger impacts. The MAPE serves as a measure of overall fit, irrespective of the direction of the error.

Table 4-10: Mean Percentage Error and Mean Absolute Percentage Error by Baseline and Event Day

Event Date	3-Day		3-Day, Morning Adjustment	
	MPE	MAPE	MPE	MAPE
June 20	-13.1%	13.1%	-0.7%	4.3%
July 5	-1.1%	4.7%	0.8%	6.6%
Aug. 29	-0.7%	4.9%	-2.5%	5.2%
Aug. 30	0.3%	4.8%	-1.4%	6.2%
Aug. 31	-9.8%	9.9%	-2.0%	6.9%
All Events	-3.7%	6.7%	-1.4%	6.1%

There are no general rules that apply to the interpretation of these measures. With respect to the MAPE, smaller values are better, though there might be cases where it is desirable to have consistency across event days. For the MPE, smaller absolute values are generally better, but there might be cases where the direction of error can take precedence over the magnitude of the error, depending on how the numbers are being used.

In the case of this study, the 3-Day Morning Adjustment baseline is clearly better than the unadjusted 3-Day baseline. The 3-Day Morning Adjustment baseline has a lower overall MAPE of 6.1% and only overestimates the load by an average of 1.4%, based on the MPE. Additionally, the unadjusted 3-Day baseline has a wider range of MAPEs, with a low of 4.7% and a high of 13.1%. These results suggest that the adjustment applied to the 3-Day Morning Adjustment baseline is serving its intended purpose of calibrating the estimated load to conditions during the morning of the event.

4.5 Comparison of Impact Estimates for BEC 2007 Events Across Methods

Table 4-11 presents the quantile distribution of hourly impacts across all notified participants and all event days. This table shows the variability in impacts that can result from the various types of baselines that have been calculated. While all baselines have a median impact greater than zero, the 3-Day baseline has both the largest median impact and registers the largest impact.[25] The 10-Day baseline has the smallest median impact, which is reasonable to expect based on the methodology, and uses an average of the ten most recent valid days. There is no intuitive rule to explain the results for the adjusted baselines. Each individual participant's adjustment is based on consumption during specific hours on the day of or the day before the event, so the adjustments can produce a variety of results. An

[25] This comparison excludes the BEC Method baseline, which is based on a customers Peak Load since it has been shown to be unrealistically inflated.

interesting item to note from the following table is how the median impact from the 3-Day Morning Adjusted baseline is equal to the median impact from the site-level regression model, which is another illustration of the 3-Day Morning Adjusted baseline being a good proxy for econometric models.

Table 4-11: Distribution of Hourly Participant Impacts

	Representative Day Method				Econometric Regression Models		Program Approved
Quantile	**3-Day**	**3-Day, Morning Adj**	**10-Day**	**10-Day, Morning Adj**	**Site-Level Model**	**Aggregate Model**	**BEC Method Peak Red**
100% Max	3.18	2.75	2.97	2.79	3.30	NA	4.11
75% Q3	0.22	0.15	0.13	0.14	0.16	NA	0.72
50% Median	0.08	0.06	0.02	0.05	0.06	NA	0.42
25% Q1	0.01	0.02	-0.06	0.01	0.01	NA	0.24
0% Min	-0.38	-0.34	-0.71	-0.48	-0.73	NA	-0.18

Table 1-1 compares the estimated BEC Program impacts that were calculated as part of this evaluation (using two representative day methods, two econometric modeling methods, and the BEC Peak Reduction method[26]) to those calculated by PG&E and the BEC, as well as those filed with the CPUC by PG&E. As this comparison shows, the two econometric models developed for this evaluation (an aggregate customer model and a site-level model) resulted in the most conservative impact estimates (11.2 and 11.6 MW, respectively)[27]. Both of the representative day methods resulted in impacts were similar in magnitude to those from the econometric models, however the 3-Day Morning Adjusted baseline method was the closest proxy to the modeling results (12.6 MW vs. 14.8 MW for the 3-Day unadjusted baseline). Being able to use the 3-Day Adjusted baseline as a proxy for the econometric results is a significant finding since it is believed that the econometric models produce results that are more robust and better at dealing with weather and day-of-week sensitivity issues that affect office and commercial buildings (which make up about 90% of the customers in this program) than the representative day methods. However, the representative day methods

26 The BEC Peak Reduction method was used within the 2007 program year to calculate each participants load reduction. It is calculated as the difference between a customer's average peak demand and their actual usage during the event.

27 One marked difference between the two econometric models is the impact associated with the last event. The difference in the contributing accounts is not significant enough to cause this. It is a result of the difference in the two methodologies. The aggregate models used a time series approach that incorporate all days and hours and modeled event-day specific indicator variables and, as a result, was able to capture the effect of the three event days leading into the three-day weekend. In contrast, the site-level models used a less rigorous approach that excluded event days, weekends, and holidays and therefore its predicted load for August 31 did not take into account the days preceding it, leading to a much higher predicted load.

are easier to implement (they are similar to methods currently used for impact estimation and program settlement for other PG&E DR programs) and are reasonably transparent to participants which make them favorable for program settlement methods. The results from this evaluation support the CPUC's decision to switch to the 3-Day Morning-Of Adjusted baseline for Program Year 2008 settlement.

Table 4-12: Comparison of Estimated Impacts across Evaluation Methods and with PG&E Reported Impacts and Program Goals

				Average Hourly Impact (in MW)									
				Evaluation Calculated					PG&E Calc.[3]		BEC Calculated[4]		
				Representative Day		BEC	Econometric Models		Rep Day	BEC			
Event Date	**Start Hour**	**End Hour**	**Parts**	**3-Day**	**3-Day AM Adj**	**Peak Red**	**Agg[1]**	**Site Level[2]**	**3-Day**	**Peak Red**	**Peak Red[5]**	**Goal Credit[6]**	**Filed with CPUC[7]**
7/5/07	14	19	73	11.7	9.5	51.1	10.7	11.9	8.1	48.7	54.3	24	49.5
8/29/07	13	18	95	11.4	13.3	47.9	12.1	11.6	12.6	51.1	47.4	29.9	45.1
8/30/07	13	18	98	10.8	13.3	48.5	11.2	11.7	11.3	47.4	46.7	30.2	44.9
8/31/07	13	18	98	24.5	13.7	61.1	0.7	11.7	24.1	60.1	61.3	30.2	57.9
2007 Avg				**14.8**	**12.6**	**52.3**	**8.5**	**11.7**	**14.4**	**52.0**	**52.0**	**28.9**	**49.4**

1. Based on the Aggregated Participant Daily Load Models
2. Based on the Site-Level Participant Models
3. From BEC Load Event Files (provided by PG&E)
4. From BEC 2007 Performance_Enjoin Data.xls (received 7/8/08 from BEC Staff)
5. Peak Reduction Calculated as Peak kW (baseline) minus Average Usage during Event
6. Goal Credit Calculated as Peak kW minus FSL
7. From Dec 2007 Monthly ILP Report

Finally, Table 4-13 compares the average estimated BEC Program impact per event across the three program years based on the 10-Day Adjusted baseline. This baseline method is used for this comparison since it was the primary method presented for the 2005/2006 evaluation. As this table shows, the average event impact has increased substantially since 2005 (1.9 MW per event in 2005 versus 8.0 MW in 2007 using the 10-Day Adjusted baseline method); however, this is being driven by the number of participants per event (15 in 2005 versus 89 in 2007). The average impact per participant has remained constant around 100 kW, which equates to approximately a 5% load drop.

Table 4-13: Comparison of Average BEC Program Impacts – 2005 to 2007 Based on 10-Day Adjusted Baseline[28]

Program Year	Average # of Participants per Event	Average Impact per Participant (MW)	Average Load Reduction per Participant	Average Estimated Event Impact (MW)
2005	15	0.13	8%	1.9
2006	31	0.08	4%	2.5
2007	89	0.09	6 %	8.0

[28] Comparison across years was made with 10-Day Adjusted baseline since that was the Representative Day method used for the 2005/2006 report.

5

Findings, Conclusions, and Recommendations

This section discusses the key findings stemming from the analysis performed to support the impact and process evaluation of the PY 2007 BEC demand response program. Recommendations concerning program changes and/or enhancements based on these findings are presented at end of this section.

5.1 Findings

The following process and impact related findings were made based on the analysis performed for this evaluation.

5.1.1 Process Findings

- ***Customers are very satisfied with the BEC Program.*** BEC participants reported very high levels of satisfaction with all aspects of the program. The highest levels of satisfaction were reported for the program overall (98%), the financial incentives offered for participation (96%), the process by which they were notified about an event (93%), and the number of events called (93%).
- ***On-site technical assessments are very helpful to BEC participants.*** Seventy-four percent of participants reported that upon their enrollment in the BEC Program, they received an on-site technical assessment and 97% of those characterized this assistance as somewhat or extremely helpful. These on-site assessments help participants identify what load reduction actions can be realistically taken at a given facility, determine an appropriate firm service level (FSL), and create an executable curtailment plan that can be implemented during an event to achieve their load reduction goal. Ninety-seven percent of those who received an audit reported they had taken all or some (equally split 49% and 49%) of the actions that had been prescribed by the audit during a curtailment event in 2007. BEC staff report that participants who have received an on-site assessment take different actions on BEC event days than those who have not received an audit.
- ***Event notification was effective for 2007 events.*** All BEC participants who had received notification about a 2007 BEC event reported the notification process was effective (92% said it was "Very Effective", 8% said it was "Somewhat Effective"). It is important to note that in 2007, the four events called

were all "day-ahead" events which provided participants approximately 24 hours to prepare for the curtailment; however, had a "day-of" event been called (with a program minimum of one hour notice), nearly half of the participants reported that would not provide them the time necessary to be able to fully respond.

- ***Event participation is high.*** Eighty-seven percent of BEC participants reported participating in all of the 2007 BEC events. Reasons for not participating included "Operation was already was shut down," "Did not receive event notification," "Could not respond in time," and "Could not reduce load on that particular day,"
- ***Relatively low level of impacts resulting from event curtailment.*** Twenty-eight percent of BEC participants reported their curtailment actions had an impact on personnel comfort or productivity. The primary impact reported was a warm or uncomfortable work environment (73%).
- ***Reducing overhead lighting and turning off non-critical equipment are primary curtailment actions.*** Both of these actions were reported to be taken by more than two-thirds of those who had curtailed load for a BEC event. Approximately one-third indicated they had allowed the temperature to rise in tenant-occupied spaces. The majority of these actions were manual driven (49%) or only partially automated (47%)
- ***Being a good corporate citizen is a primary driver for program participation.*** Three-quarters of participants surveyed ranked "Being a good corporate citizen" as an "extremely significant" reason for their participation in the BEC program. Program managers interviewed mentioned that some customers have requested more public recognition for their participation in program.
- ***Majority of enrolled customers are new to DR.*** A main driver for the BEC Program was to attract PG&E customers who have been classified as Hard-to-Reach (HTR) with respect to DR programs. HTR customers in this context were defined as "customers who are difficult to recruit (to DR programs) or have not consistently or significantly participated in load reduction events." Based on the self-report data from the participant survey, roughly three-quarters of the BEC participants were new to DR (i.e., they had either never been enrolled in a DR program or had never participated in a DR program event). However, 50% of those surveyed stated that, to the best of their knowledge, they had never been recruited for another DR program (and thus cannot be definitively classified as HTR). More than two-thirds of the 50% of participants who could recall being recruited reported they had enrolled (past or present) in the DR program. Two-thirds of those reported had participated in at least one of the events called for this alternate DR program.
- ***BEC Program is effective at overcoming primary customer barriers.*** The BEC Program was designed and is operating in a way to effectively overcome the primary barriers to DR (such as a perceived inability to reduce load, the lack of DR expertise and enabling-technology, and complicated program requirements) faced by customers within its target market. The key program elements that

address these barriers include providing detailed site assessments to identify (and quantify) load reduction actions that can be taken during an event, installing gateway technology that provides real-time feedback of curtailment activities during program events, and simplifying program requirements such that customers have a clear and concise load reduction goal for all events and a straightforward incentive structure.

5.1.2 Impact Findings

- BEC Program participants were able to make various levels of load reductions for particular events. The average peak load reduction achieved by program participants was 5.9% in 2007.
- The average event and non-event day loads for the summer of 2007 were substantially lower than the peak demand estimated using the BEC's load reduction methodology. Using peak demand, as defined under the BEC program, leads to large over-estimations of event impacts, especially when compared to the Representative Day approach and the regression modeling methodology.
- Compared to the aggregate ex post impacts, the 3-Day and the Adjusted 3-Day baselines performed fairly well. When the events were on hot days, the Representative Day baselines performed similarly. When the weather was milder or other atypical conditions existed, the Adjusted 3-Day baseline performed better than the 3-Day baseline.
- Based upon a comparison of BEC's impact estimates with those estimated using the Representative Day and regression analysis approaches, Itron finds that the average on-peak demand and FSL are substantially higher than its average non-event day load across the summer. This indicates that these values are set unrealistically high and, thus, participants are being paid for load reductions that never occur.

5.2 Conclusions

Evaluating the PY2007 BEC program provided a unique opportunity to compare different methodologies of estimating the load reduction impacts for program events. Under the Representative Day approach, a number of baselines were calculated (such as the 3-Day and the Adjusted 3-Day) and the differences between these baselines and actual event day loads were calculated and examined as estimates of program settlement impacts. Regression analysis was also employed to estimate program ex post impacts that take into account variations in day type and weather. The load impacts estimated using these methodologies were in stark contrast to the impacts estimated by the BEC. The approach used by the BEC was to take the difference between a firm's highest average monthly on-peak demand and its actual load on event days.

Based on the findings presented in this section and the results discussed in this evaluation report, it is apparent that there are significant issues with the methods currently used by the BEC to estimate event settlement impacts. Based upon the findings presented in this impact evaluation, there are significant advantages to using the Representative Day impact estimation methods and regression models. The Representative Day methods presented in this analysis are easy to implement and are reasonably transparent to participants. However, they are not as robust at dealing with weather and day-of-week sensitivity issues that affect office and commercial buildings as regression models and are not recommended for ex post impact estimation. For settlement purposes, regression baseline methods are more difficult to implement and less transparent to program participants.

5.3 Recommendations

Based on the findings and conclusions, this evaluation makes the following recommendations:

1. Conduct another process and impact evaluation in 2008 to determine how the changes implemented in 2008 have impacted BEC participant satisfaction and event participation. Pay close attention to whether the program is still effective at helping customers overcome the barriers they face to DR program participation.
2. Talk with the PG&E personnel responsible for overseeing the technicians who make changes to customers' meters to determine if there is a way to reduce the time BEC participants wait in the "metering queue" and thus delay their ability to fully participate in BEC events.
3. Continue to offer BEC participants comprehensive site assessments and revisit sites that have experienced changes to their building personnel or energy usage.
4. Abandon the current method of estimating BEC program settlement impacts for participants and, instead, rely upon Representative Day estimation methods for program settlement purposes. Rely upon the regression methodology for ex post impact evaluation purposes only and ensure that the Representative Day settlement baseline method used continues to estimate program impacts as accurately as possible. Both of these methods are far superior to the estimation of impacts based upon the current average on-peak demand method used by the BEC Program.
6. Based upon the findings from this impact evaluation, the most accurate Representative Day method has proven to be the Adjusted 3-Day method. Use this methodology to estimate the baseline demand of program participants. Incentive payments made to program participants should be based upon the impacts estimated based upon the Adjusted 3-Day method rather than the current method, which relies upon the difference between firm service level and peak demand. This current method exaggerates the load reduction occurring from the program.