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Load Impact Estimates for Southern California Edison's Demand Response Programs:
Agricultural and Pumping Interruptible Program
Real Time Pricing

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1 Executive Summary

This report provides ex post and ex ante load impact estimates for the following two Southern California Edison (SCE) demand response programs:

- Agricultural and Pumping Interruptible (AP-I); and
- Real Time Pricing tariff (RTP).

1.1 Demand Response Load Impact Summary

Two demand response (DR) programs are addressed in this report: AP-I and RTP. AP-I, which is an event based resource, had one event in 2011. Ex post load impact estimates are provided for this event. For RTP, which is a non-event based program, ex post load impact estimates are developed for the average weekday and monthly system peak day for each month in 2011, as required by the load impact protocols.

Ex ante load impact estimates were developed for the years 2012 through 2022. For each program, ex ante estimates are provided for the average customer and for all enrolled customers under two sets of weather conditions (representing 1-in-2 and 1-in-10 weather years), by CAISO Local Capacity Area (LCA) and forecast year. The number of potential load impact tables runs in the thousands. Only selected tables are presented in this report. Electronic copies of spreadsheet models meeting all load impact filing requirements will be submitted along with this report.

1.1.1 Agricultural and Pumping Interruptible Program

The Agricultural and Pumping Interruptible (AP-I) program provides a monthly credit to eligible agricultural and pumping customers for allowing SCE to temporarily interrupt electric service to their pumping equipment during CAISO or other system emergencies. As of September 30, 2011, there were 973 customers enrolled in the AP-I program. Enrollment is highest in the Ventura LCA, where 721 customers are enrolled. The second largest region is the LA Basin LCA, with 180 enrollees, followed by the Outside LA Basin LCA, with 72 participants.

In 2011, there was one AP-I event, compared to two in 2010. The 2011 event took place on September 21 and lasted from 1:48 PM to 3:01 PM. From 2 PM to 3 PM, the load drop was 34.9 kW per participant with an aggregate load drop of 33.4 MW. The aggregate impact represents an 80.5% reduction relative to the reference load of 41.5 MW.

Ex ante load impact estimates were developed for the years 2012 through 2022. Once enrollment and the switch success rate reach their expected steady state in the 2015 to 2022 time period, the program is projected to be capable of delivering nearly 55 MW of load reduction, which occurs during the May monthly peak under 1-in-10 weather conditions. If SCE reaches its forecast target of a 95% switch success rate by August 2014, the aggregate 1-in-2 load impact is 47.9 MW and the 1-in-10 result is 51.7 MW.

1.1.2 Real Time Pricing

The Real Time Pricing (RTP) program is a dynamic pricing tariff that charges participants for the electricity they consume based on hourly prices that vary according to day type and temperature. It attempts to incorporate both the time-varying components of energy costs and generation capacity costs. The RTP tariff consists of nine hourly pricing profiles that vary by season, day type and a range of temperatures measured at the Downtown Los Angeles site on the previous day. The tariff is available to large commercial and industrial customers (i.e., customers eligible for service under Schedule TOU-8). Because the rate schedules are linked to variation in weather, participants experience more high-price days during extreme weather years than in normal weather years. As of December 2011, there were 131 enrolled accounts on the RTP tariff.

For the ex post analysis, the overall impacts were calculated as the difference between regression-predicted load under 2011 RTP prices and under the Otherwise Applicable Tariff (OAT). Impacts were estimated for each monthly system peak day in 2011. The largest estimated impact occurred on September 7, 2011, which generated an average load drop of 159.7 kW and an aggregate load drop of nearly 21 MW during the peak period from 1 PM to 6 PM. The aggregate impact represents a 15.8% reduction relative to the reference load of 133.1 MW.

Ex ante load impact estimates were developed for the years 2012 through 2022. Once enrollment reaches its expected steady state in August 2015, the program is projected to be capable of delivering 32.5 MW of load reduction on the days with the highest RTP prices, which occur during September under 1-in-2 system conditions and June, August and September in a 1-in-10 weather year. SCE system load typically peaks during August and September. For these monthly peaks in a 1-in-2 weather year, aggregate impacts are expected to increase by 38% and 44% respectively from 2012 to 2015, as a result of new enrollment. In a 1-in-10 weather year, aggregate impacts are expected to increase by 44% for both the August and September peaks from 2012 to 2015.

1.2 Report Structure

The remainder of this report contains one section for each of the two DR resources described above. Impact estimates for the AP-I and RTP programs are contained in Sections 2 and 3. Each section provides a brief overview of the program and current enrollment values. This is followed by a discussion of analysis methodology, including an assessment of the validity of the models and estimates. The remainder of each section presents the ex post and ex ante load impact estimates.

2 Agricultural and Pumping Interruptible Program

The Agricultural and Pumping Interruptible (AP-I) program provides a monthly credit to eligible agricultural and pumping customers for allowing SCE to temporarily interrupt electric service to their pumping equipment during CAISO or other system emergencies. As of September 30, 2011, there were 973 customers enrolled in the AP-I program.[1]

SCE called one AP-I event in 2011. It took place on September 21 and lasted from 1:48 PM through 3:01 PM. Ex post load impact estimates for this event are presented in this section, along with an assessment of switch failure based on an analysis of load data.

2.1 Program Background and History

Agricultural and pumping customers with a measured demand of 37 kW or greater, or with at least 50 horsepower of connected load per service account, are eligible to participate in the AP-I program. Participating customers must already be served under an agricultural and pumping rate schedule. The AP-I program is not available to customers receiving the off-peak credit provided under Schedule PA-1 or to customers served under experimental rate schedules. The AP-I program may also not be available in certain areas of SCE's territory where communication signaling equipment has not been installed or signal strength is inadequate to activate or deactivate an interruption. With some restrictions, AP-I participants may enroll in other programs, but they cannot be paid for the same reduced load.

When an interruption is deemed necessary and is allowed under the terms of the tariff, SCE sends a signal to the load control device installed on a customer's pumping equipment. The signal automatically turns off the equipment for the entire duration of the interruption event. AP-I customers can request to receive courtesy notifications of the start and end time of an interruption through means of email, pager and/or text message to a cell phone. The number of interruptions cannot exceed 1 per day, 4 in any calendar week and 25 per calendar year. The duration of an interruption cannot exceed 6 hours per interruption, 40 hours per calendar month or 150 hours per calendar year.

In exchange for allowing SCE to interrupt pumping service during times of emergencies, AP-I customers receive a monthly credit. The credits vary between customers on a TOU rate and those on a non-TOU rate. For the over 95% of participants on a TOU rate, the credit is based on their directly measured average hourly peak and mid-peak demand. Customers receive $17.22 per summer average on-peak kW, $3.66 per summer average mid-peak kW and $1.25 per winter average mid-peak kW. For the remaining 5% of customers on a non-TOU rate, the credit is $0.01164/kWh, which applies to energy use all year long. Prior to 2009, the incentive consisted solely of a flat kWh credit for all participants.

The AP-I program has been in operation since the 1970s, although it was closed to new enrollment starting in 1998. As a result of the increased need for DR resources after the energy crisis in 2000-2001, the program was reopened on April 3, 2001.[2] In March 2006, SCE was authorized to increase marketing

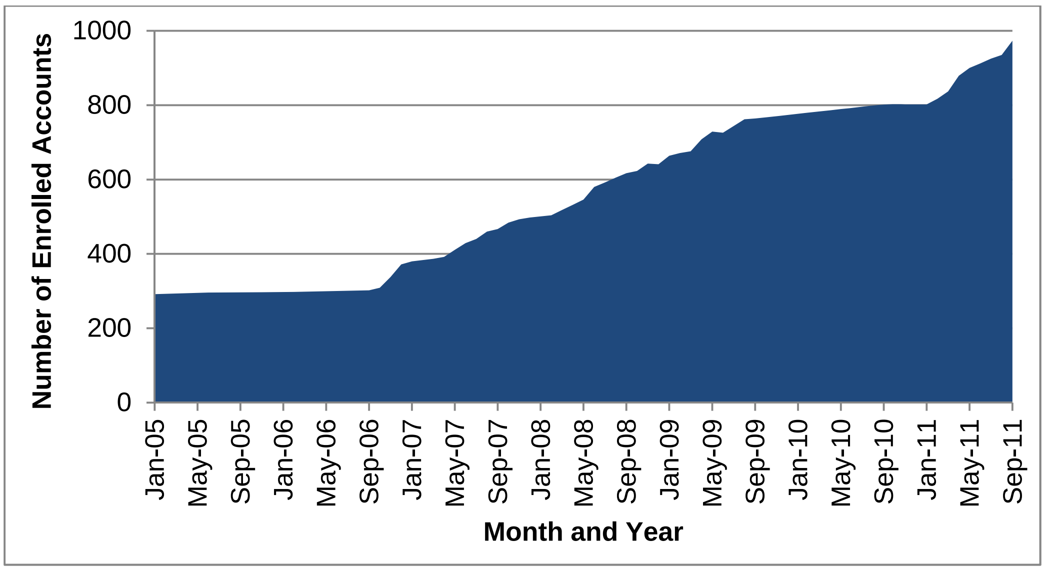
[1] Five customers lacked sufficient interval data to be included in the analysis, while interval data could not be obtained for another ten customers. Thus, the analysis dataset actually consisted of 958 customers.

[2] Pursuant to D.01-04-006.

of the AP-I program with the objective of significantly increasing enrollment. As part of this effort, SCE eliminated the up-front charge to customers for AP-I equipment and installation. Considerable effort was made to increase enrollment since SCE had not actively marketed the AP-I program for a number of years and customer awareness was low.

As a result of the increased marketing and outreach, the number of enrolled service accounts increased from roughly 300 at the beginning of 2006 to 664 service accounts by the end of January 2009, and to 802 by the end of September 2010. The program served 973 customers as of September 2011. The impact of this marketing can be seen in Figure 2-1. Enrollment has more than tripled since March 2006 when the marketing of AP-I was approved. Enrollment is highest in the Ventura LCA, where 721 customers are enrolled. The second largest region in terms of enrollment is the LA Basin LCA, with 180 enrollees, followed by the Outside LA Basin LCA, with 72 participants.

Figure 2-1:
Number of Enrolled Accounts
January 2005 to September 2011



2.2 Analysis Methodology

When an AP-I event is called, the direct load control device completely shuts down the electricity supply to the pump. For most pumps the load drop is nearly instantaneous, although some systems are configured to ramp down pumps over a period of five minutes. In most instances, the pump is directly metered, but this is not true in every case. A relatively small number of customers have additional loads such as lighting on the same circuit as the pumps. Those loads, however, are a minor fraction of the overall measured loads, especially since, by AP-I's program design, pumps have a minimum demand of 50 hp (approximately 35 kW).

Because the measured load is almost exclusively made up by pumps, the expected load impact is approximately equal to the reference load when the direct load control switch is activated. The aggregate load impact across all accounts should equal the aggregate reference load minus the load associated with any accounts that have non-working switches. Given this, the primary focus of the analysis was on estimating reference loads. An estimate of working switches was also developed based on the 2011 event.

2.2.1 Model Development

The regression model used to predict the reference load was designed to accurately predict average load for the agricultural pumps in the AP-I program given the time of day, day of week and month. The focus was primarily on the accuracy of the predictions in the months and hours of the day when an event is likely to be called.

Functional form was closely considered, and then several specifications were tested using the ordinary least squares regression technique with robust standard error corrections. The selection of the final regression model was based on its accuracy under normal and extreme conditions and its theoretical consistency. The final model predicts energy use for agricultural pumping using variables that capture the following factors:

- Typical load shapes associated with operational schedules;
- Temperature variables designed to capture the impact of weather on agricultural pumping; and
- DR event variables to capture load impacts associated with AP-I events and other DR program events for customers that are dually-enrolled.

The model also included auto-regressive lagged variables to help calibrate the regression output specifically to the event day.

Individual regressions were run for the 958 customers with sufficient data available for analysis. The same specification was used for all customers. The dependent variable was the average hourly energy use for each AP-I agricultural pump and the explanatory variables are summarized in Table 2-1.

Mathematically, the regressions can be expressed by:

$$kW_t = A + \sum_{i=1}^{24}\sum_{j=1}^{12} B_{ij} \times Hour_i \times Month_j + \sum_{i=1}^{24}\sum_{j=1}^{3} C_{ij} \times Hour_i \times DayType_j +$$

$$\sum_{i=1}^{24} D_i \times Hour_i \times TotalCDH_t + \sum_{i=1}^{24} E_i \times Hour_i \times TotalCDHsqr_t$$

$$\sum_{i=1}^{24} F_i \times Hour_i \times TotalHDH_t + \sum_{i=1}^{24} G_i \times Hour_i \times TotalHDHsqr_t$$

$$\sum_{i=1}^{24} H_i \times Hour_i \times OtherDR_t + \sum_{i=1}^{24} I_i \times Hour_i \times Eventday + \varepsilon_t$$

Table 2-1:
AP-I Model Variables and Definitions

Variable	Definition
kW_t	Average hourly demand (kW) for each time period
A	Estimated constant term
B_{ij} through I_i	Regression model parameters
$Hour_i$	Series of binary variables for each hour, which account for the basic hourly load shape of the customer after other factors such as weather and prices are accounted for
$DayType_j$	Series of binary variables representing three different day types (Mon, Tues-Thurs, Fri); weekends are excluded from the model
$Month_j$	Series of binary variables for each month designed to reflect seasonality in loads
$TotalCDH_t$	Sum of cooling degree hours (base 65) for the day
$TotalCDHsqr_t$	$TotalCDH_t$ squared
$TotalHDH_t$	Sum of heating degree hours (base 65) for the day
$TotalHDHsqr_t$	$TotalHDH_t$ squared
$OtherDR_t$	Binary variable representing a customer's participation in another DR event
$Eventday_t$	Binary variable representing an AP-I event day
e_t	Is the error term

The same model, without the auto-regressive component, was used to estimate ex-ante impacts.

2.2.2 Model Accuracy and Validity Assessment

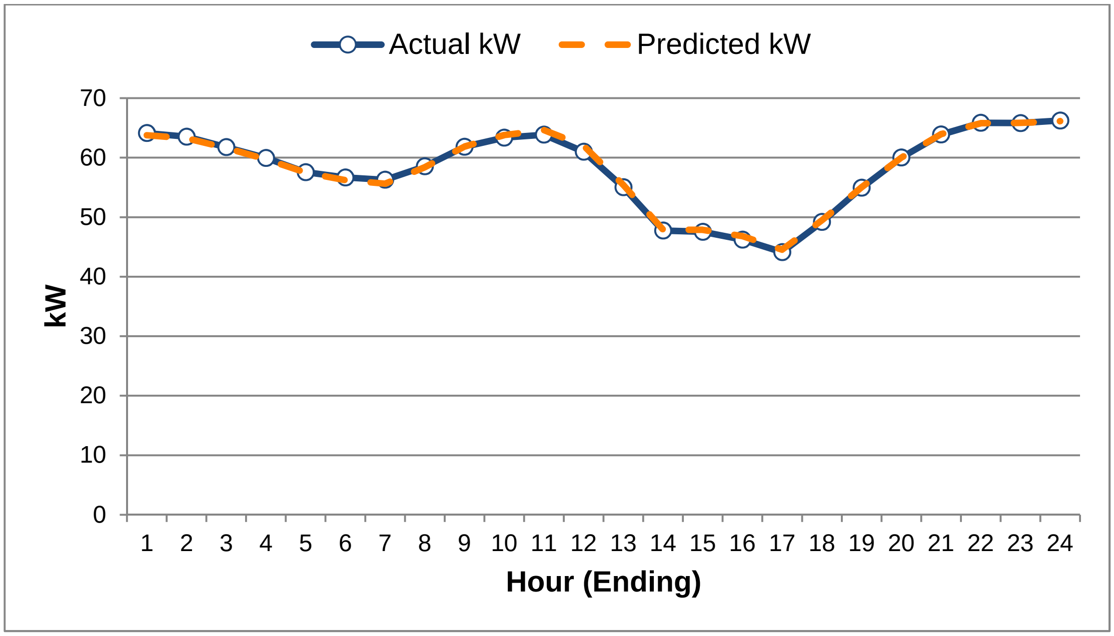
Although regressions were run for each individual customer in the AP-I program, what matters most is that the reference loads for all customers combined, or for selected groups of customers, are accurate. Given that load impacts are equal to the reference load (after a small adjustment for switch failure), any error in the estimated reference load would cause an error in the estimated load impact.

Out-of-sample Validation

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

Figure 2-2 shows the results of the out-of-sample validation for the top nine maximum system load weekdays for each customer. As seen in the figure, the model accurately predicts load on high system load weekdays even if those days are not included in the estimating sample. The difference between actual and predicted load did not exceed 1.6% in any hour. More importantly, the percentage error is lowest during the afternoon when events are most likely to be called. Between 1 PM and 6 PM, the model slightly over predicts by 0.8%, on average.

Figure 2-2:
Actual v. Predicted Average Load
Out-of-Sample Validation for Top Nine Maximum System Load Weekdays

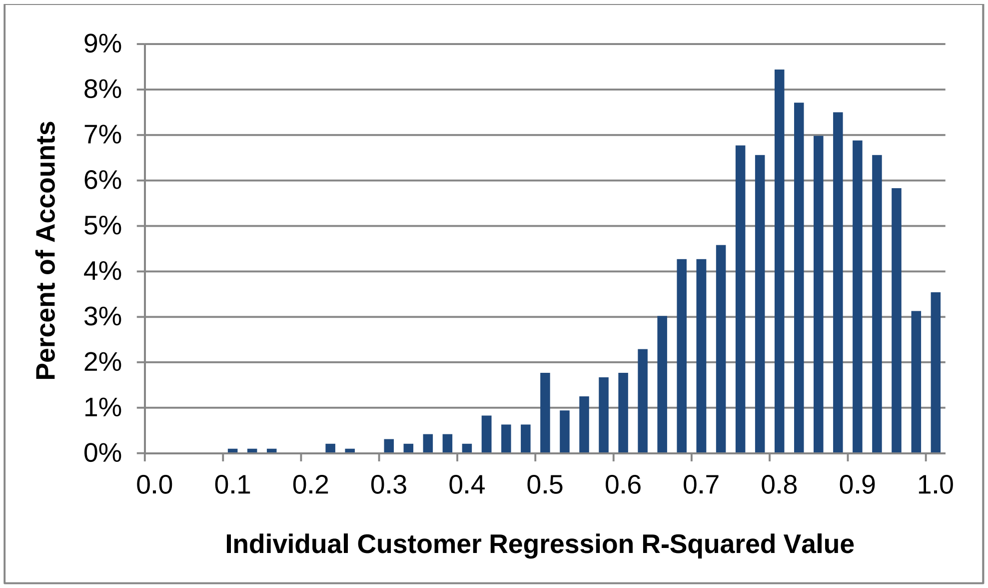


Goodness-of-Fit Measures

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

Figure 2-3 shows the distribution of R-squared values from the individual customer regressions for AP-I customers. More than half of AP-I customers had R-squared values above 0.80, which suggests that the model predicts relatively well for most AP-I customers. The lower one-third of all individual regressions had R-squared statistics up to 0.725.

Figure 2-3:
Distribution of R-squared Values from Individual Regressions for AP-I Customers



In order to estimate the average customer R-squared values for each crop type, LCA or the program as a whole, the regression-predicted and actual electricity usage values were averaged across all customers for each date and hour. This process produced regression predicted and actual values for the average customer, which enabled the calculation of errors for the average customer and the calculation of the R-squared value. The R-squared values for the average participant and for the average customer by segment were estimated using the following formula:[3]

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

Table 2-2:
Description of the R-squared Variables

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

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

Table 2-3 summarizes the amount of variation explained by the regression model by LCA. For all customers, the model has an *aggregate* R-squared value of 0.99, which means that the model explains 99% of variation in *aggregate* AP-I load. Although some of the individual regression R-squared values are low (as shown in Figure 2-3), the model is accurate when predicting aggregate AP-I load overall and across key segments of the population.

Table 2-3:
Aggregate R-squared Values by LCA

Group Type	Segment	Number of Customers	Aggregate R-Squared
LCA	LA Basin	179	0.96
	Outside LA Basin	72	0.97
	Ventura	707	0.99
	Overall	**958**	**0.99**

2.3 Ex Post Load Impact Estimates

Ex post load impact estimates based on hourly interval data for the AP-I event in 2011 are provided in this section. This event lasted from 1:48 PM to 3:01 PM on September 21; thus, only the hour from 2 PM to 3 PM saw an impact across an entire hour. In addition, it was a test event, called to examine the program's impact should it be required during extreme conditions. System load on September 21 was relatively low; in fact, with a system peak of 15,758 MW, demand was considerably lower than the 22,107 MW annual peak seen on September 7.

Figure 2-4 shows the average load impact per AP-I customer in each hour on September 21. From 2 PM to 3 PM, the load drop was 34.9 kW per participant. Figure 2-5 shows the aggregate load impact for each hour of the day. The aggregate load drop from 2 PM to 3 PM was 33.4 MW. This represents an 80.5% reduction relative to the reference load of 41.5 MW. From 3 PM to 4 PM, the aggregate load impact was still 21.9 MW as many AP-I customers did not manually reactivate their pumps immediately after the event.

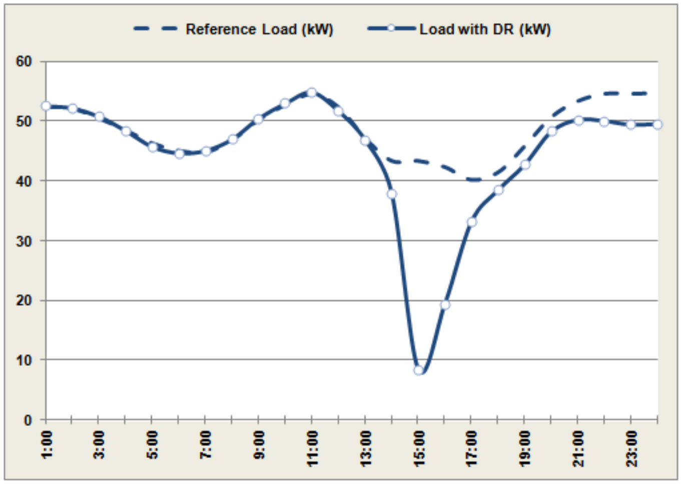
Figure 2-4:
Average AP-I Ex Post Load Impact (kW) per Participant for September 21, 2011

TABLE 1: Menu options

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

TABLE 2: Output

Number of Accounts	958
Event Window	1:48 PM - 3:01 PM



Hour Ending	Reference Load (kW)	Load with DR (kW)	Load Impact (kW)	Weighted Temp (F)	Uncertainty Adjusted Impact - Percentiles				
					10th	30th	50th	70th	90th
1:00	52.4	52.6	-0.1	69.8	-1.1	-0.5	-0.1	0.3	0.9
2:00	52.2	52.2	0.0	69.6	-1.1	-0.5	0.0	0.4	1.0
3:00	50.5	50.8	-0.3	68.5	-1.3	-0.7	-0.3	0.1	0.7
4:00	48.5	48.4	0.1	66.3	-0.9	-0.3	0.1	0.5	1.1
5:00	46.3	45.8	0.5	66.1	-0.5	0.1	0.5	1.0	1.6
6:00	45.0	44.7	0.4	64.8	-0.7	0.0	0.4	0.8	1.4
7:00	44.8	45.1	-0.3	66.4	-1.3	-0.7	-0.3	0.1	0.7
8:00	46.8	47.0	-0.2	71.3	-1.2	-0.6	-0.2	0.3	0.9
9:00	50.3	50.5	-0.2	76.9	-1.3	-0.7	-0.2	0.2	0.8
10:00	52.8	53.0	-0.2	82.2	-1.2	-0.6	-0.2	0.2	0.8
11:00	54.6	54.9	-0.3	84.9	-1.3	-0.7	-0.3	0.1	0.7
12:00	52.4	51.7	0.7	87.6	-0.4	0.2	0.7	1.1	1.7
13:00	47.2	46.9	0.2	90.4	-0.8	-0.2	0.2	0.7	1.3
14:00	43.3	38.0	5.3	91.9	4.3	4.9	5.3	5.7	6.4
15:00	43.3	8.5	34.9	92.5	33.8	34.4	34.9	35.3	35.9
16:00	42.3	19.4	22.9	92.8	21.9	22.5	22.9	23.3	23.9
17:00	40.1	33.2	6.9	91.7	5.9	6.5	6.9	7.4	8.0
18:00	41.4	38.5	2.9	89.6	1.8	2.5	2.9	3.3	3.9
19:00	45.8	42.8	3.1	86.3	2.0	2.6	3.1	3.5	4.1
20:00	50.7	48.3	2.4	83.4	1.3	2.0	2.4	2.8	3.5
21:00	53.4	50.3	3.1	80.3	2.1	2.7	3.1	3.6	4.2
22:00	54.7	50.1	4.6	77.0	3.5	4.1	4.6	5.0	5.6
23:00	54.7	49.5	5.2	73.5	4.1	4.8	5.2	5.6	6.3
0:00	54.8	49.6	5.2	72.2	4.1	4.7	5.2	5.6	6.2
	Reference Energy Use (kWh)	Energy Use with DR (kWh)	Change in Energy Use (kWh)	Cooling Degree Hours (Base 70)	Uncertainty Adjusted Impact - Percentiles				
					10th	30th	50th	70th	90th
Daily	1,168.42	1,071.71	96.71	234.7	91.61	94.62	96.71	98.80	101.81

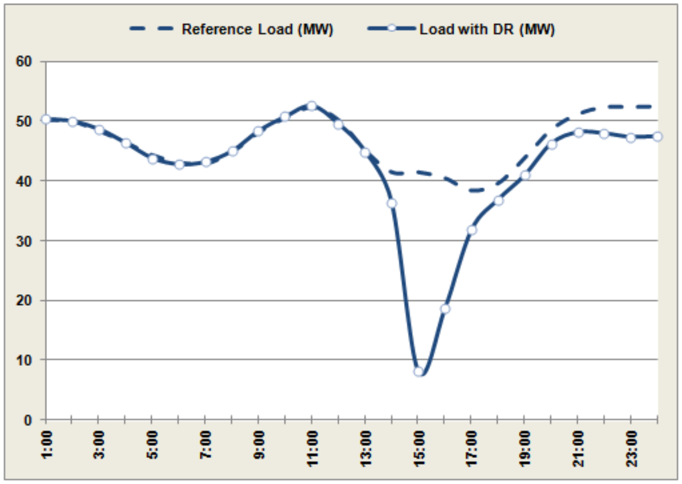
Figure 2-5:
Aggregate AP-I Ex Post Load Impact (MW) for September 21, 2011

TABLE 1: Menu options

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

TABLE 2: Output

Number of Accounts	958
Event Window	1:48 PM - 3:01 PM



Hour Ending	Reference Load (MW)	Load with DR (MW)	Load Impact (MW)	Weighted Temp (F)	Uncertainty Adjusted Impact - Percentiles				
					10th	30th	50th	70th	90th
1:00	50.2	50.4	-0.1	69.8	-1.1	-0.5	-0.1	0.3	0.9
2:00	50.0	50.0	0.0	69.6	-1.0	-0.4	0.0	0.4	0.9
3:00	48.4	48.7	-0.3	68.5	-1.3	-0.7	-0.3	0.1	0.7
4:00	46.5	46.4	0.1	66.3	-0.9	-0.3	0.1	0.5	1.1
5:00	44.4	43.8	0.5	66.1	-0.5	0.1	0.5	0.9	1.5
6:00	43.2	42.8	0.4	64.8	-0.6	0.0	0.4	0.8	1.3
7:00	42.9	43.2	-0.3	66.4	-1.3	-0.7	-0.3	0.1	0.7
8:00	44.9	45.0	-0.2	71.3	-1.1	-0.6	-0.2	0.2	0.8
9:00	48.2	48.4	-0.2	76.9	-1.2	-0.6	-0.2	0.2	0.8
10:00	50.6	50.8	-0.2	82.2	-1.2	-0.6	-0.2	0.2	0.8
11:00	52.3	52.6	-0.3	84.9	-1.3	-0.7	-0.3	0.1	0.7
12:00	50.2	49.6	0.6	87.6	-0.4	0.2	0.6	1.1	1.6
13:00	45.2	44.9	0.2	90.4	-0.8	-0.2	0.2	0.6	1.2
14:00	41.5	36.4	5.1	91.9	4.1	4.7	5.1	5.5	6.1
15:00	41.5	8.1	33.4	92.5	32.4	33.0	33.4	33.8	34.4
16:00	40.5	18.6	21.9	92.8	20.9	21.5	21.9	22.3	22.9
17:00	38.4	31.8	6.7	91.7	5.7	6.2	6.7	7.1	7.6
18:00	39.6	36.9	2.8	89.6	1.8	2.4	2.8	3.2	3.8
19:00	43.9	41.0	2.9	86.3	1.9	2.5	2.9	3.3	3.9
20:00	48.6	46.3	2.3	83.4	1.3	1.9	2.3	2.7	3.3
21:00	51.2	48.2	3.0	80.3	2.0	2.6	3.0	3.4	4.0
22:00	52.4	48.0	4.4	77.0	3.4	4.0	4.4	4.8	5.4
23:00	52.4	47.4	5.0	73.5	4.0	4.6	5.0	5.4	6.0
0:00	52.5	47.5	5.0	72.2	3.9	4.5	5.0	5.4	6.0
	Reference Energy Use (MWh)	Energy Use with DR (MWh)	Change in Energy Use (MWh)	Cooling Degree Hours (Base 70)	Uncertainty Adjusted Impact - Percentiles				
					10th	30th	50th	70th	90th
Daily	1,119.35	1,026.70	92.65	234.7	87.76	90.65	92.65	94.65	97.53

Table 2-4 shows the 2011 average and aggregate AP-I ex post load impact estimates by LCA. In the LA Basin LCA, the percent load reduction was 74.7%; in the Ventura LCA, AP-I customers provided around 81.4% load impacts. Aggregate load reductions were concentrated in the Ventura LCA, which accounted for 84% of the total impacts.

Table 2-4:
2011 Average and Aggregate AP-I Ex Post Load Impact Estimates by LCA

Event Date and Hour	LCA	Number of Customers	Avg. Reference Load (kW)	Avg. Load with DR (kW)	Avg. Load Reduction (kW)	% Load Reduction	Aggregate Load Reduction (MW)
Sept. 21, 2011 (2-3 PM)	LA Basin	179	25.2	6.4	18.8	74.7%	3.4
	Outside LA Basin	72	35.8	7.9	27.9	77.9%	2.0
	Ventura	707	48.7	9.0	39.6	81.4%	28.0
	All Customers	**958**	**43.3**	**8.5**	**34.9**	**80.5%**	**33.4**

2.4 Switch Failure Analysis

When devices are successfully activated, load impacts for the AP-I program are essentially equivalent to the reference load. However, not all pumps are shut down when events are called, due to either equipment or communication failures. The 2011 event data were used to estimate the percent of customers for whom communication with the load control switch was successful.

To begin the analysis, FSC calculated each customer's maximum load and compared it with the value in the hour prior to each event. If the ratio of electricity use in that hour on the event day to the maximum load was less than 0.05, the customer was deemed to not be operating their pump and was dropped from the sample. After this screening analysis, there were 437 observations left.

For the remaining customers, load in the hour prior to the event (12 to 1 PM) was compared with load during the final hour of the event period (2 to 3 PM). There was a wide distribution of load reductions across participants. This leaves a significant number of participants that appeared to drop only a portion of their load. A break point was utilized in an effort to separate normal fluctuation of load from event participation. The distribution of load drop percentages was examined carefully and a 50% load drop was set as the breakpoint. A drop of less than 50% between the hour prior to the event and the final hour of the event period was determined to be unperturbed fluctuation in load. Load drops of greater than 50% were deemed to be consistent with successful switch communication.

Table 2-5 provides the estimated switch success rates for each event going back to 2008. The switch success rate for the September 21, 2011, event was 85.4%. The other results are from previous AP-I evaluations and are intended to show how the switch success rate has changed over time. From the 2008 event to the September 2010 event, the estimated switch success rate increased from 78% to 85.4%; for the 2011 event, the success rate remained the same. However, Table 2-5 only includes four data points. Without more event data, it is difficult to conclusively determine whether or not the switch success rate has improved substantially.

Table 2-5:
Estimated AP-I Switch Success Rates by Event Date

Event Date	Number of Observations	Switch Success Rate
Nov. 7, 2008	311	78.0%
July 29, 2010	433	80.8%
Sept. 27, 2010	342	85.4%
Sept. 21, 2011	**384**	**85.4%**

As indicated in last year's AP-I evaluation, SCE plans to significantly increase switch success rates during the 2012 to 2014 time period. As such, the ex ante analysis assumes that switch success rates improve over time. Table 5-5 provides the forecast of AP-I switch success rates that is used in the ex ante analysis. The 2011 switch success rates are used as a base. As shown in Table 2-6, the LA Basin LCA starts out with a relatively low rate of 80% because it had a higher rate of switch failure in 2011. Starting with the next funding cycle in 2012, the switch success rates for each LCA improve to 95% by August 2014 and are held constant for all forecast years thereafter.

Table 2-6:
Forecast of AP-I Switch Success Rates Used in Ex Ante Analysis

Forecast Year	LA Basin	Outside LA Basin	Ventura	Overall
2011 ex-post	75%	82%	88%	85%
2012 (August)	80%	85%	90%	88%
2013 (August)	88%	90%	92%	91%
2014 (August)	95%	95%	95%	95%
2015-2021	95%	95%	95%	95%

2.5 AP-I Ex Ante Load Impact Estimates

The AP-I program grew from 802 to 973 accounts from September 2010 to September 2011. The program is expected to experience continued enrollment growth over the next few years. In August 2012, the program is expected to have 1,050 customers, while in August 2014 it is expected to have 1,093 customers. Afterwards, enrollment is assumed to remain constant until the end of the ex ante forecast period (2022). For ex ante purposes, the load impacts of new participants are assumed to be the same as existing AP-I customers.

Figures 2-6 and 2-7 show the reference load and estimated load with DR for the average customer on a typical event day based on 1-in-2 and 1-in-10 year weather conditions for the year 2014. Impacts are reported for 2014 because it is the year in which enrollment growth and switch success rates reach a steady state. For a 1-in-2 typical event day, the estimated load impact for the average participant is 43.7

kW from 1 PM to 6 PM. For a 1-in-10 typical event day, the estimated load impact for the average participant is slightly higher, at 45.9 kW. As a result of the improved switch success rates, the load impact is 95% of the reference load under both weather year conditions.

The remainder of the hourly ex ante load impact estimates that are required by the protocols for AP-I, including uncertainty adjusted estimates, can be found in the electronic appendix titled, “SCE 2011 AP-I Ex-Ante Load Impact Tables.”

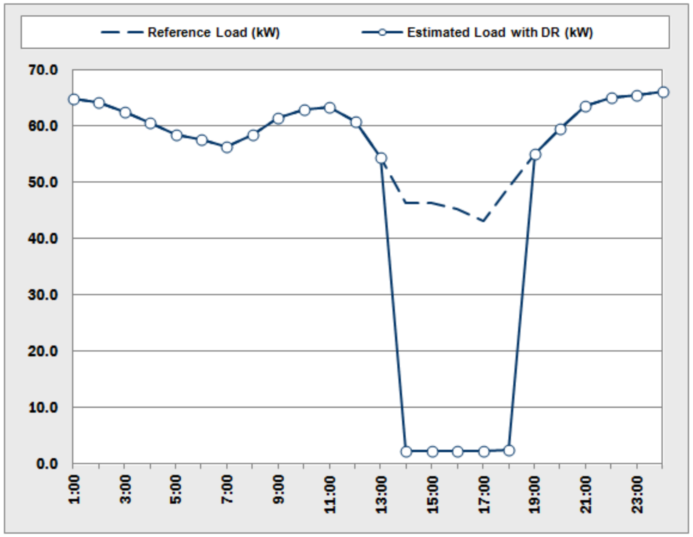
Figure 2-6:
AP-I Average Load Impact (kW) per Customer in 2014
for a Typical Event Day Based on 1-in-2 Year Weather Conditions

TABLE 1: Menu options

Type of Results	Average Enrolled Account
Weather Year	1-in-2
Forecast Year	2014
Day Type	Typical Event Day
Customer Characteristic	All Customers
Expected Switch Success Rate (August 2014)	95.0%

TABLE 2: Output

Number of Accounts	1093
Switch Success Rate	95.0%
Average Load Impact (kW) (1-6pm)	43.7
% Load Impact (1-6pm)	95.0%



Hour Ending	Reference Load (kW)	Estimated Load with DR (kW)	Load Impact (kW)	% Load Impact	Weighted Temp (F)	Uncertainty Adjusted Impact - Percentiles				
						10th	30th	50th	70th	90th
1:00	64.9	64.9	0.0	0.0%	71.0	-1.5	-0.6	0.0	0.6	1.5
2:00	64.2	64.2	0.0	0.0%	68.5	-1.5	-0.6	0.0	0.6	1.5
3:00	62.4	62.4	0.0	0.0%	66.7	-1.5	-0.6	0.0	0.6	1.5
4:00	60.6	60.6	0.0	0.0%	65.6	-1.5	-0.6	0.0	0.6	1.5
5:00	58.5	58.5	0.0	0.0%	63.8	-1.5	-0.6	0.0	0.6	1.5
6:00	57.5	57.5	0.0	0.0%	62.3	-1.5	-0.6	0.0	0.6	1.5
7:00	56.4	56.4	0.0	0.0%	62.4	-1.5	-0.6	0.0	0.6	1.5
8:00	58.4	58.4	0.0	0.0%	66.4	-1.5	-0.6	0.0	0.6	1.5
9:00	61.4	61.4	0.0	0.0%	72.5	-1.5	-0.6	0.0	0.6	1.5
10:00	62.8	62.8	0.0	0.0%	77.2	-1.5	-0.6	0.0	0.6	1.5
11:00	63.4	63.4	0.0	0.0%	82.1	-1.5	-0.6	0.0	0.6	1.5
12:00	60.6	60.6	0.0	0.0%	85.3	-1.5	-0.6	0.0	0.6	1.5
13:00	54.3	54.3	0.0	0.0%	88.4	-1.5	-0.6	0.0	0.6	1.5
14:00	46.4	2.3	44.0	95.0%	90.0	42.6	43.4	44.0	44.6	45.5
15:00	46.2	2.3	43.9	95.0%	91.8	42.5	43.3	43.9	44.5	45.4
16:00	45.2	2.3	43.0	95.0%	92.5	41.5	42.4	43.0	43.6	44.4
17:00	43.2	2.2	41.0	95.0%	92.5	39.5	40.4	41.0	41.6	42.4
18:00	49.1	2.5	46.7	95.0%	91.7	45.2	46.1	46.7	47.3	48.1
19:00	55.0	55.0	0.0	0.0%	89.8	-1.5	-0.6	0.0	0.6	1.5
20:00	59.5	59.5	0.0	0.0%	87.0	-1.5	-0.6	0.0	0.6	1.5
21:00	63.5	63.5	0.0	0.0%	83.1	-1.5	-0.6	0.0	0.6	1.5
22:00	65.1	65.1	0.0	0.0%	80.2	-1.5	-0.6	0.0	0.6	1.5
23:00	65.4	65.4	0.0	0.0%	77.8	-1.5	-0.6	0.0	0.6	1.5
0:00	66.2	66.2	0.0	0.0%	75.9	-1.5	-0.6	0.0	0.6	1.5

	Reference Energy Use (kWh)	Energy Use with DR (kWh)	Change in Energy Use (kWh)	% Change in Energy Use	Cooling Degree Hours (Base 70)	Uncertainty Adjusted Impact - Percentiles				
						10th	30th	50th	70th	90th
Daily	1,390.1	1,171.5	218.6	15.7%	238.9	-69.8	100.6	218.6	336.6	506.9

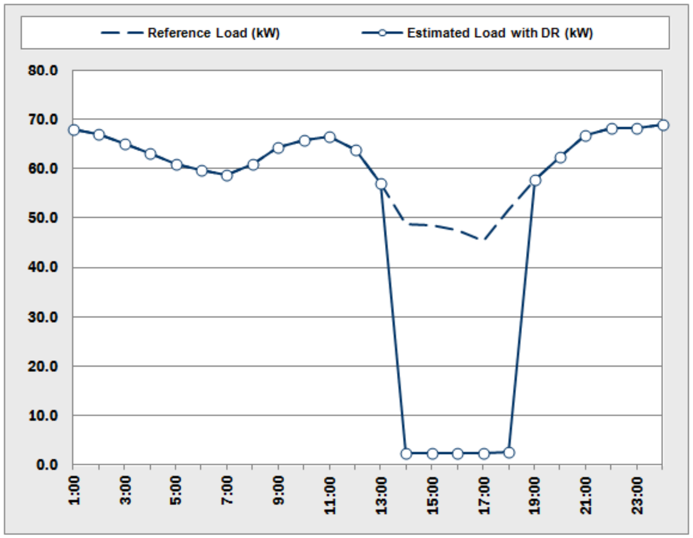
Figure 2-7:
AP-I Average Load Impact (kW) per Customer in 2014
for a Typical Event Day Based on 1-in-10 Year Weather Conditions

TABLE 1: Menu options

Type of Results	Average Enrolled Account
Weather Year	1-in-10
Forecast Year	2014
Day Type	Typical Event Day
Customer Characteristic	All Customers
Expected Switch Success Rate (August 2014)	95.0%

TABLE 2: Output

Number of Accounts	1093
Switch Success Rate	95.0%
Average Load Impact (kW) (1-6pm)	45.9
% Load Impact (1-6pm)	95.0%



Hour Ending	Reference Load (kW)	Estimated Load with DR (kW)	Load Impact (kW)	% Load Impact	Weighted Temp (F)	Uncertainty Adjusted Impact - Percentiles				
						10th	30th	50th	70th	90th
1:00	67.9	67.9	0.0	0.0%	79.0	-1.5	-0.6	0.0	0.6	1.5
2:00	67.1	67.1	0.0	0.0%	77.5	-1.5	-0.6	0.0	0.6	1.5
3:00	65.1	65.1	0.0	0.0%	75.8	-1.5	-0.6	0.0	0.6	1.5
4:00	63.1	63.1	0.0	0.0%	73.6	-1.5	-0.6	0.0	0.6	1.5
5:00	60.9	60.9	0.0	0.0%	72.3	-1.5	-0.6	0.0	0.6	1.5
6:00	59.7	59.7	0.0	0.0%	70.8	-1.5	-0.6	0.0	0.6	1.5
7:00	58.8	58.8	0.0	0.0%	70.6	-1.5	-0.6	0.0	0.6	1.5
8:00	60.9	60.9	0.0	0.0%	73.3	-1.5	-0.6	0.0	0.6	1.5
9:00	64.3	64.3	0.0	0.0%	77.7	-1.5	-0.6	0.0	0.6	1.5
10:00	65.9	65.9	0.0	0.0%	82.0	-1.5	-0.6	0.0	0.6	1.5
11:00	66.4	66.4	0.0	0.0%	85.5	-1.5	-0.6	0.0	0.6	1.5
12:00	63.8	63.8	0.0	0.0%	88.8	-1.5	-0.6	0.0	0.6	1.5
13:00	57.0	57.0	0.0	0.0%	91.8	-1.5	-0.6	0.0	0.6	1.5
14:00	48.8	2.4	46.4	95.0%	93.8	44.9	45.8	46.4	47.0	47.8
15:00	48.5	2.4	46.1	95.0%	95.5	44.6	45.5	46.1	46.7	47.6
16:00	47.5	2.4	45.1	95.0%	96.7	43.6	44.5	45.1	45.7	46.6
17:00	45.4	2.3	43.1	95.0%	97.1	41.6	42.5	43.1	43.7	44.6
18:00	51.7	2.6	49.1	95.0%	96.3	47.6	48.5	49.1	49.7	50.6
19:00	57.7	57.7	0.0	0.0%	95.0	-1.5	-0.6	0.0	0.6	1.5
20:00	62.3	62.3	0.0	0.0%	91.8	-1.5	-0.6	0.0	0.6	1.5
21:00	66.7	66.7	0.0	0.0%	87.3	-1.5	-0.6	0.0	0.6	1.5
22:00	68.3	68.3	0.0	0.0%	85.1	-1.5	-0.6	0.0	0.6	1.5
23:00	68.3	68.3	0.0	0.0%	82.2	-1.5	-0.6	0.0	0.6	1.5
0:00	68.9	68.9	0.0	0.0%	80.1	-1.5	-0.6	0.0	0.6	1.5
	Reference Energy Use (kWh)	Energy Use with DR (kWh)	Change in Energy Use (kWh)	% Change in Energy Use	Cooling Degree Hours (Base 70)	Uncertainty Adjusted Impact - Percentiles				
						10th	30th	50th	70th	90th
Daily	1,454.9	1,225.1	229.7	15.8%	339.5	-64.6	109.3	229.7	350.2	524.0

Table 2-7 shows the aggregate on-peak AP-I ex ante load impact estimates for each monthly system peak day by weather year and forecast year. In accordance with the revised resource adequacy hours, the peak period is defined as 1 PM to 6 PM from April through October and 4 PM to 9 PM from November through March. Once enrollment and the switch success reach a steady state in the 2015 to 2021 time period, the program is expected to be capable of delivering up to 54 MW, which occurs during the May monthly peak under 1-in-10 weather conditions. SCE system load typically peaks during August and September. For these monthly peaks in a 1-in-2 and 1-in-10 weather year, aggregate impacts are expected to increase by 10% from 2012 to 2014 as a result of new enrollment and an improved switch success rate.

Table 2-7:
AP-I Aggregate On-Peak Load Impacts (MW)
for each Monthly System Peak Day by Weather Year and Forecast Year

Weather Year	Month	Peak Period	2012	2013	2014	2015-2022
1-in-2	Jan	4-9 PM	20.1	21.6	22.9	23.9
	Feb	4-9 PM	21.6	23.2	24.6	25.5
	Mar	4-9 PM	24.8	26.7	28.4	29.2
	Apr	1-6 PM	38.9	41.4	44.0	45.2
	May	1-6 PM	44.2	47.0	49.9	51.0
	Jun	1-6 PM	43.7	46.5	49.3	50.2
	Jul	1-6 PM	43.7	46.5	49.4	50.0
	Aug	1-6 PM	42.4	45.1	47.9	48.2
	Sep	1-6 PM	39.2	41.7	44.1	44.3
	Oct	1-6 PM	35.7	38.0	40.0	40.2
	Nov	4-9 PM	28.1	29.9	31.4	31.4
	Dec	4-9 PM	24.4	25.9	27.2	27.2
1-in-10	Jan	4-9 PM	21.5	23.0	24.4	25.5
	Feb	4-9 PM	24.0	25.8	27.4	28.4
	Mar	4-9 PM	31.4	33.7	35.8	37.0
	Apr	1-6 PM	40.8	43.5	46.2	47.4
	May	1-6 PM	47.1	50.1	53.2	54.4
	Jun	1-6 PM	46.5	49.5	52.6	53.5
	Jul	1-6 PM	44.3	47.1	50.0	50.6
	Aug	1-6 PM	45.8	48.7	51.7	52.0
	Sep	1-6 PM	40.9	43.5	46.0	46.2
	Oct	1-6 PM	38.5	40.9	43.1	43.3
	Nov	4-9 PM	27.0	28.7	30.1	30.2
	Dec	4-9 PM	19.8	21.0	22.0	22.0

Table 2-8 shows how the aggregate August monthly peak load impacts vary as a function of the switch success rate that is ultimately achieved in August 2014. As with any forecast, unforeseen factors may result in a switch success rate that is higher or lower than expected. If SCE reaches its forecast target of a 95% switch success rate by August 2014, the aggregate 1-in-2 load impact is 47.9 MW and the 1-in-10 result is 51.7 MW. However, if the switch success rate stays at 85%, the 1-in-2 and 1-in-10 load impacts are 12% lower. In addition, these results assume that the projected enrollment of 1,093 customers by August 2014 is achieved, which is another key variable that can be affected by unforeseen factors. It is also assumed that new participants are similar to the existing population in terms of electricity usage. If new participants are significantly larger or smaller than the existing AP-I population, the aggregate load impacts will be higher or lower than expected, even if the customer enrollment target is achieved. All factors - switch success rates, enrollment and the size of new participants - must be tracked closely to ensure that SCE reaches the expected MW level of load impacts that is presented in this ex ante analysis.

Table 2-8:
AP-I Aggregate August Monthly Peak Load Impacts (MW)
by August 2014 Switch Success Rate

Switch Success Rate (August 2014)	Aggregate 2014 August Monthly Peak Load Impacts (MW)	
	1-in-2	1-in-10
80%	40.4	43.5
82.5%	41.6	44.9
85% (current)	42.9	46.2
87.5%	44.1	47.6
90%	45.4	48.9
92.5%	46.7	50.3
95% (forecast)	47.9	51.7
97.5%	49.2	53.0

2.6 Recommendations

As discussed in Section 5.5, future AP-I aggregate load impacts are closely tied to switch success rates, enrollment and the size of new participants. By August 2014, SCE expects to:

- Improve the switch success rate from 85% to 95%;
- Increase AP-I enrollment from 973 to 1,090 participants; and
- Enroll new participants that have similar usage to the existing AP-I population.

All of these factors must be tracked closely to ensure that SCE reaches the expected MW level of load impacts that is presented in this ex ante analysis.

As discussed in last year's evaluation, we recommend improving the switch success rate though the following steps:

1. Run tests or actual events during the summer, when pumps are on. Ideally, the test event would occur during peak hours and last long enough to determine whether pumps that were operating immediately before the event ramped down when the event signal was sent to the switches.

2. Analyze the 15 minute interval data to identify units that were on immediately prior to the event but were not activated. The criteria for determining activation must factor in that some pumps ramp down over five minutes and that additional loads not controlled by switches are measured by the same meter for a small fraction of participants.
3. Target the identified accounts for a switch activation inspection and repair, as appropriate.

Calling events facilitates the ability to identify pumps that are not providing load reduction and improve the switch success rates. Out of necessity, the improvement in switch success rates would be conducted over the course of two or three years. It takes time to call events, identify units that are not providing load reduction, inspect and repair. Moreover, not all units will be on for a given event due to the variable nature of pump loads. As a result, the process is an iterative one, requiring continuous adjustment to meet stated goals.

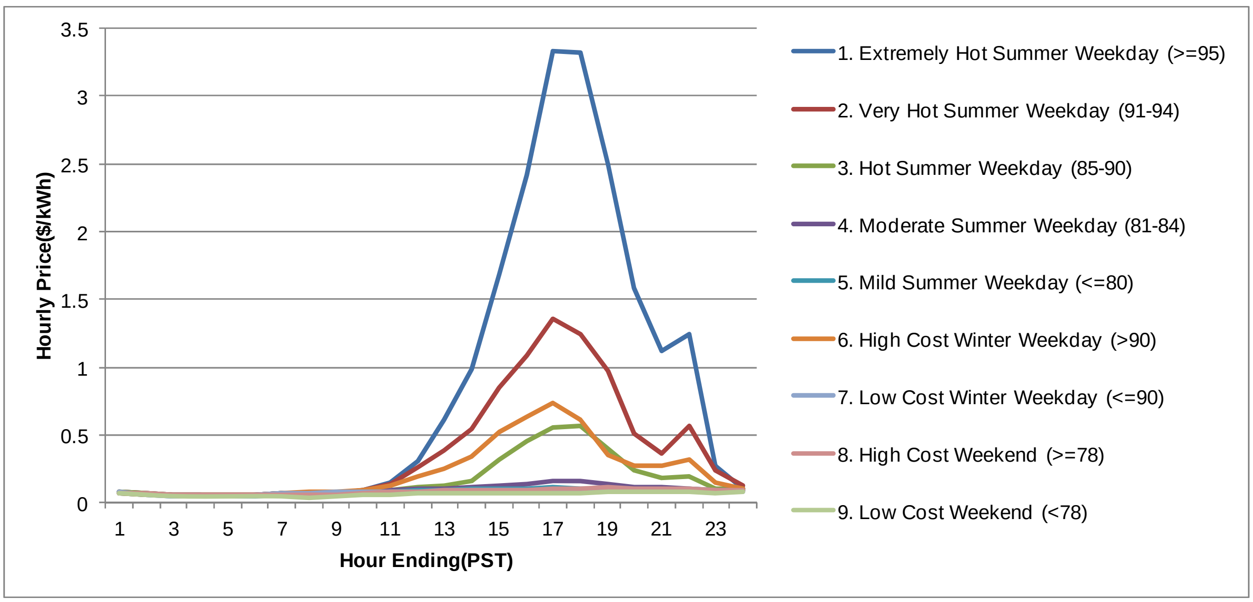
3 Real Time Pricing Program

This section contains the RTP program background and history, analysis methodology and ex post load impact estimates.

3.1 Program Background and History

The Real Time Pricing (Schedule RTP-2 or RTP) program is a dynamic pricing tariff that charges participants for the electricity they consume based on hourly prices that vary according to day type and temperature. It attempts to incorporate both the time-varying components of energy costs and generation capacity costs. The RTP tariff consists of nine hourly pricing profiles that vary by season, day type and a range of temperatures measured at the Downtown Los Angeles site on the previous day (see Figure 3-1). The tariff is available to large commercial and industrial customers (i.e., customers eligible for service under Schedule TOU-8). Because the rate schedules are linked to variation in weather, participants experience more high-price days during extreme weather years than in normal weather years.

Figure 3-1:
2011 RTP Hourly Price Profiles by Schedule
(2 kV and Below[4])



In compliance with the CPUC guidance on dynamic pricing, the RTP prices were revised in October 2009. The rate redesign follows the CPUC's guidance on dynamic rates and represents a significant increase in the peak-period prices faced by RTP customers on extremely hot summer weekdays, high cost winter weekdays and very hot summer weekdays.

[4] The applicable price schedules vary slightly for customers connected at less than 2kV, 2kV to 50kV and greater than 50kV.

On an extremely hot summer weekday (when the downtown LA temperature is 95°F or higher on the previous day), the current RTP price peaks at $3.33/kWh from 5 PM to 6 PM. Previously, the maximum price on an extremely hot summer weekday was around $2.25/kWh (32% lower). The increases are offset by lower rates during off-peak hours. Overall, the peak to off-peak price ratio for the redesigned tariff is substantially larger and encourages load shifting from peak periods to off-peak periods, particularly during high-price days.[5]

The RTP program was closed to new enrollment in 1998 with the implementation of the deregulated market structure, but opened again in January 2008. Enrollment grew from 101 accounts at the beginning of 2011 to 131 accounts in December 2011. Although RTP has grown in the past year, the aggregate program load is still dominated by a few very large manufacturing customers in the LA Basin local capacity area (LCA). The three largest participants account for 70% of total program load. Across all customers, the manufacturing sector in the LA Basin LCA accounts for 48% of total program load.

3.2 Analysis Methodology

The ex post load impact estimates are based on individual customer regressions. The regression models were estimated on load data from 2009 to 2011 and used to predict load based on RTP prices and the otherwise applicable tariff (OAT), which is TOU-8 option B. The load impacts are the difference between demand in each hour with and without RTP prices in effect. Since different price schedules are in effect on a daily basis, estimating customer response to prices is necessary for determining RTP impacts. After the model was estimated, demand impacts associated with each rate schedule were estimated by comparing predicted load based on the RTP price with predicted load based on the OAT.

Table 3-1 shows the historical frequency of the different price schedules for 2009-2011. During this time period, there were 12 extremely hot summer weekdays when the highest prices were in effect. The low cost winter weekday is the most common price schedule, occurring on 44% of days from 2009 to 2011. Although high-price days are infrequent, there is sufficient variation in the 2009 to 2011 time period from which to model how load responds to RTP prices.

[5] Although RTP does not have specific peak and off-peak hours like a TOU rate, similar terminology is used to describe the rate (i.e., "peak period" refers to 1 PM to 6 PM and "off-peak period" refers to other hours).

Table 3-1:
Historical Frequency of RTP Price Schedules by Year

RTP Price Schedule	2009	2010	2011
1. Extremely Hot Summer Weekday (95° F & above)	6	4	2
2. Very Hot Summer Weekday (91° to 94° F)	5	7	1
3. Hot Summer Weekday (85° to 90° F)	16	7	12
4. Moderate Summer Weekday (81° to 84° F)	18	10	15
5. Mild Summer Weekday (80° F & below)	42	58	56
6. High Cost Winter Weekday (91° F & above)	5	4	5
7. Low Cost Winter Weekday (90° F & below)	162	164	163
8. High Cost Summer/Winter Weekend (78° F & above)	49	40	30
9. Low Cost Summer/Winter Weekend (77° F & below)	62	71	81
Total	**365**	**365**	**365**

3.2.1 Model Development

The final regression models were estimated using individual customer time series data. The dependent variable in the model is the average hourly demand. Model specifications depended on a customer's size and sensitivity to weather. Some very large customers had separate, more simplified models to account for their unique load patterns.

The foundation of the model is the relationship between load and hourly prices. Price and price squared are interacted with hour for the 12 noon to 10 PM time period, which is when there is substantial price variation. From 10 PM to 11 AM, RTP prices are consistently low and do not vary substantially, which is why it is unnecessary to include hourly price variables for that time period. The price ratio variable is interacted with all hours of the day because it varies substantially depending on the maximum price for the day. It also captures load shifting to hours when prices are relatively low.

Considering that the RTP price schedule varies with temperature, it is important that pricing effects are not confounded with the weather variables. Therefore, weather variables are not included for manufacturing customers, which are not sensitive to changes in temperature. Large manufacturing facilities may have some usage related to heating or cooling, but it is likely an insignificant portion of the overall load. In RTP, manufacturing and mining customers have an average load of 1.7 MW, whereas the other industries average less than 0.2 MW. For these smaller non-manufacturing facilities, the weather variables are included.

Mathematically, the regression can be expressed by:

$$kW_t = A + \sum_{i=13}^{22} B_i \times Hour_i \times Price_t + \sum_{i=13}^{22} C_i \times Hour_i \times PriceSQR_t$$
$$+ \sum_{i=1}^{24} D_i \times Hour_i \times PriceRatio_t + \sum_{i=1}^{24} \sum_{j=1}^{5} E_{ij} \times Hour_i \times DayType_j$$
$$+ \sum_{i=1}^{24} \sum_{j=1}^{12} F_{ij} \times Hour_i \times Month_j + \sum_{i=1}^{24} G_i \times Hour_i \times Year2011_t + e_t$$

For weather sensitive customers, the following weather variables were also included:

$$+ \sum_{i=1}^{24} I_{ij} \times Hour_i \times TotalCDH_t + \sum_{i=1}^{24} J_{ij} \times Hour_i \times TotalHDH_t$$

Variable	Description
a	Estimated constant.
$b - j$	Estimated parameter coefficients.
$Hour$	Indicator variables representing the hours of the day, designed to estimate the effect of daily schedule on usage behavior and event impacts.
$Month$	Indicator variable for the month.
$Price$	The RTP price in effect for each hour.
$PriceSQR$	The RTP price squared.
$PriceRatio$	The ratio between the RTP price in effect for each hour and the maximum price for the day, which captures load shifting to hours when prices are relatively low.
$DayType$	A series of binary variables representing five different day types (Mon, Tues-Thurs, Fri, Sat, Sunday/Holiday).
$Year2011$	A binary variable for the most recent year of load data.
$TotalCDH$	The total number of cooling degree hours (base 70) per day.
$TotalHDH$	The total number of heating degree hours (base 70) per day.
ε_t	Error term.

3.2.2 Model Accuracy and Validity Assessment

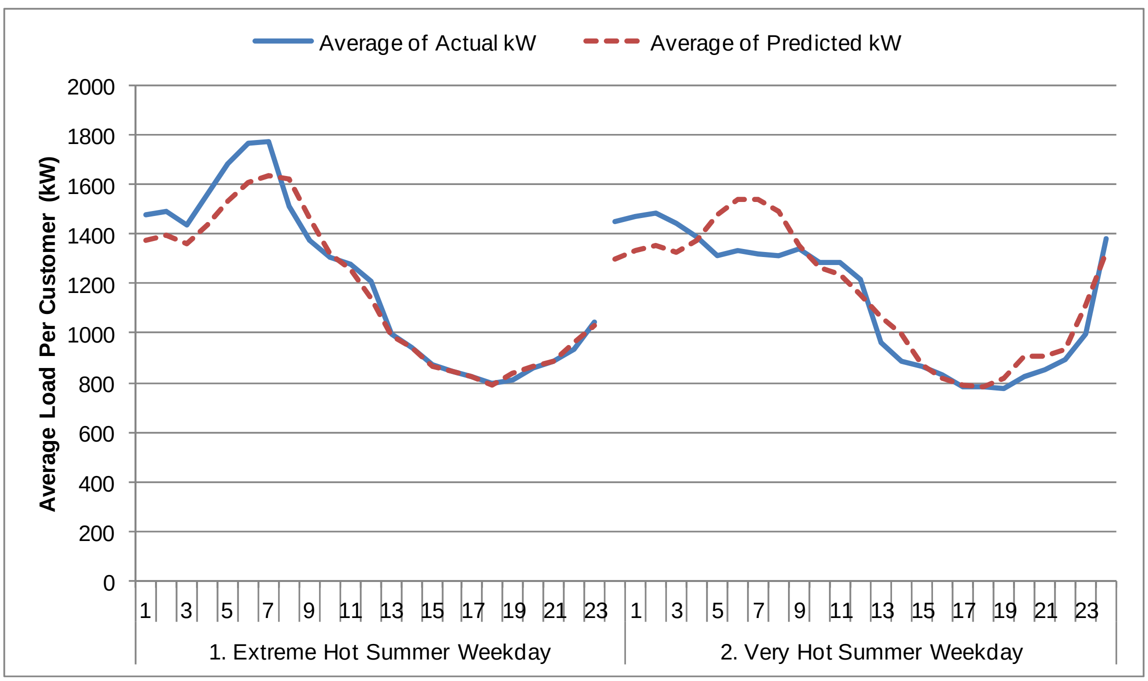
Although regressions were run for each individual customer in the RTP program, it is the accuracy of predictions for aggregate subsets of customers that is important, because errors in individual predictions tend to be random, and will cancel out upon aggregation with other customers. Also, given that load impacts are calculated as the difference between hourly usage on RTP and the OAT, it is important that the model predicts accurately across many different price levels.

Out-of-Sample Validation

The model validation focused on predicted and actual load by price schedule over the past year. In the first test of model accuracy, a series of out-of-sample validations was conducted. Rather than running the model on all of the available load data, one day from each of the summer weekday pricing profiles was randomly selected to be withheld from the estimation. Although the days are not included in the estimating sample, the model is used to predict load on those days. This process is repeated six times so that out-of-sample predictions of load are generated for six distinct sets of summer weekdays (six days from each weekday pricing schedule). Considering that there were six extremely hot summer weekdays in 2010 and 2011, this method provided out-of-sample predictions for each of the days when prices were highest.

Figure 3-2 shows the results of the out-of-sample validation for the two summer weekday schedules with the highest prices. As seen in the figure, the model accurately predicts load at high prices even if those days are not included in the estimating sample. The percentage error is lowest during the middle hours of the day when prices are as high as $3.33/kWh. Between 1 PM and 6 PM during the extremely hot summer weekdays, the percentage error is 1.0%. On the very hot summer weekdays the percentage error is only 3.7% between 1 PM and 6 PM.

Figure 3-2:
Actual v. Predicted Average Load by Price Schedule
Out-of-Sample Validation

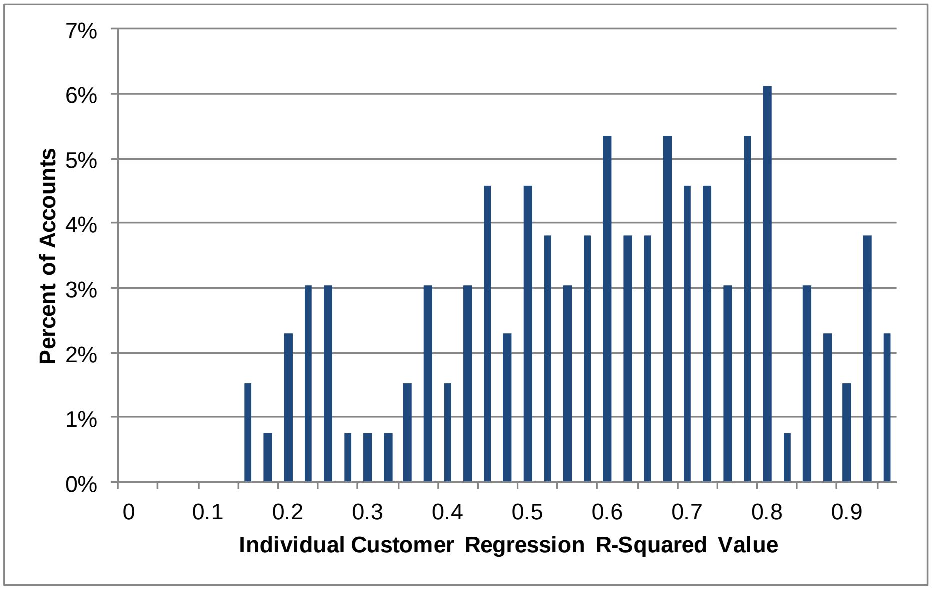


Goodness-of-Fit Measures

Although the regressions were estimated at the individual customer level, from a policy standpoint, the focus is on how the analysis performs on larger segments of the population. The errors in individual customer predictions tend to be random, and will generally cancel out upon aggregation. Therefore, the model is better at explaining the variation in electricity consumption and load impacts for the average customer (or average customer within a specific segment) than for individual customers. To illustrate this, we present measures of the explained variation, as described by the R-squared goodness-of-fit statistic, for the individual regressions and for the average customer across different characteristics such as industry and LCA.

Figure 3-3 shows the distribution of R-squared values from the individual customer regressions for RTP customers. Roughly half of the individual customer regressions had R-squared values above 0.63, which suggests that the model predicts well for most RTP customers. The lower one-third of all individual regressions had R-squared statistics up to 0.50.

Figure 3-3:
Distribution of R-squared Values from Individual Regressions for RTP Customers



In order to estimate the average customer R-squared values for each industry, LCA or the program as a whole, the regression-predicted and actual electricity usage values were averaged across all customers for each date and hour. This process produced regression predicted and actual values for the average customer, which enabled the calculation of errors for the average customer and the calculation of the R-squared value. The R-squared values for the average participant and for the average customer by segment were estimated using the following formula:[6]

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

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

In this equation:

- y_t represents actual energy use at time t;
- $\hat{y}_t$ is the regression predicted energy use at time t; and
- $\bar{y}$ is the average energy use across all time periods.

Table 3-2 summarizes the amount of variation explained by the regression model by industry, LCA and for all customers overall. For all customers, the model has an aggregate R-squared value of 0.89, which means that the model explains 89% of variation in aggregate RTP load. As noted above, program load is concentrated in the LA Basin LCA, which also has a high aggregate R-squared value of 0.9. The other LCAs have lower R-squared values, which is expected when there are fewer customers.

Table 3-2:
Aggregate R-Squared Values by Industry and LCA

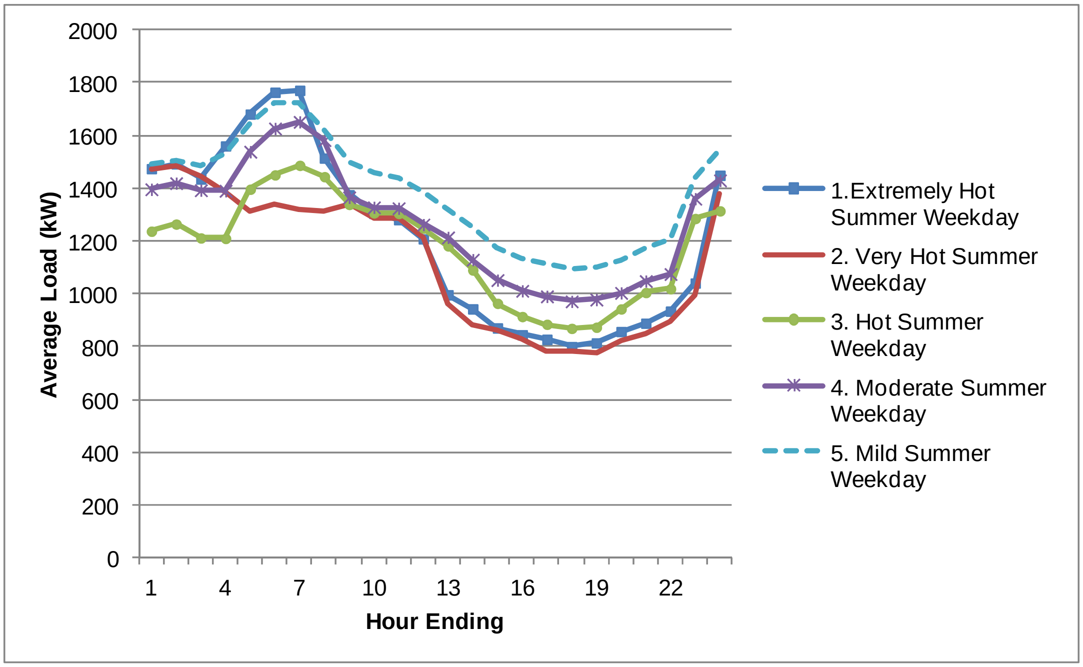
Group Type	Segment	Number of Customers	Aggregate R-Squared
Industry	Agriculture, Mining & Construction	26	0.96
	Manufacturing	57	0.73
	Wholesale, Transport & Other Utilities	32	0.45
	Offices, Hotels, Finance & Services	8	0.66
	Schools	1	0.43
	Institutional/Government	5	0.60
LCA	LA Basin	90	0.90
	Outside LA Basin	9	0.48
	Ventura	30	0.26
Overall		**129**	**0.89**

3.3 Ex Post Load Impact Estimates

The load impact protocols require that ex post impacts for non-event based programs be developed for the average weekday for each month and for the monthly system peak day. For the ex post analysis, the overall impacts were calculated as the difference between the regression predicted load under 2011 RTP prices and under the OAT.

Figure 3-4 shows the average load per customer for each RTP summer weekday price schedule in 2011. Although the graph does not control for differences in weather, seasonality or other factors, it reflects that customers did engage in peak load reductions and load shifting on days with higher price schedules. For example, when ranked from lowest to highest peak period load, the summer hourly load profiles roughly follow the strength of the price signals. The extremely hot and very hot summer weekdays have lower load levels than the other price schedules. The next highest load level is price schedule 3, followed by schedule 4 and then schedule 5, which is what is expected.

Figure 3-4:
2011 Average Load by RTP Summer Weekday Price Schedule



On September 7, 2011, SCE had its system peak day for the year. Figure 3-5 shows the average estimated load impact per RTP customer in each hour on September 7. The average load drop over the five-hour peak period from 1 PM to 6 PM was 159.7 kW. Figure 3-6 shows the aggregate load impact for each hour of the day. The aggregate load drop during the peak period was nearly 21 MW. This represents a 15.8% reduction relative to the reference load of 133.1 MW. As demonstrated by these results on September 7, the RTP program performed well when it was needed most on the annual system peak day for SCE.

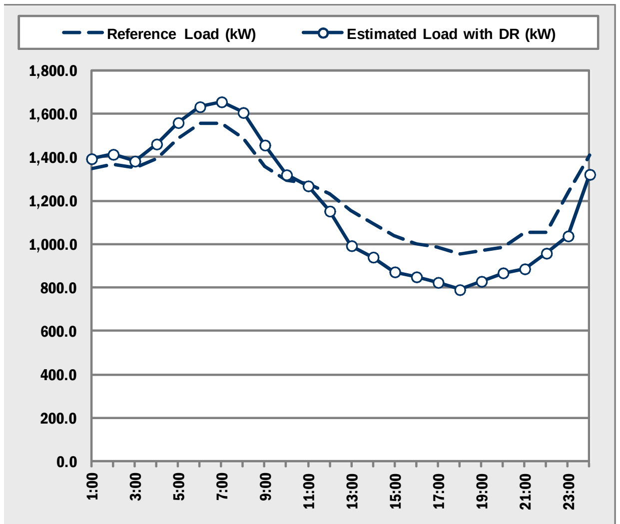
Figure 3-5:
Average RTP Ex Post Load Impact (kW) per Participant for September 7, 2011

TABLE 1: Menu options

Type of Results	Average Enrolled Account
Month	September
Day Type	System Peak Day
Customer Characteristic	All Customers

TABLE 2: Output

RTP Rate Schedule	1. Extremely Hot Summer Weekday (>=95)
Date	Wednesday, September 07, 2011
Number of Accounts	131
Average Load Impact (kW) (1-6pm)	159.7
% Load Impact (1-6pm)	15.8%



Hour Ending	Reference Load (kW)	Estimated Load with DR (kW)	Load Impact (kW)	% Load Impact	RTP Price ($/kWh)	OAT Price ($/kWh)	Weighted Temp (F)	Uncertainty Adjusted Impact - Percentiles				
								10th	30th	50th	70th	90th
1:00	1347.6	1393.3	-45.6	-3.4%	$0.07	$0.06	73.7	-255.9	-131.7	-45.6	40.4	164.6
2:00	1365.7	1413.5	-47.8	-3.5%	$0.06	$0.06	72.6	-256.3	-133.1	-47.8	37.5	160.7
3:00	1350.4	1382.5	-32.0	-2.4%	$0.06	$0.06	71.2	-238.0	-116.3	-32.0	52.2	173.9
4:00	1391.0	1460.6	-69.6	-5.0%	$0.05	$0.06	70.4	-277.5	-154.7	-69.6	15.5	138.3
5:00	1485.0	1559.4	-74.4	-5.0%	$0.05	$0.06	70.2	-285.1	-160.6	-74.4	11.7	136.2
6:00	1554.0	1632.3	-78.3	-5.0%	$0.05	$0.06	70.5	-288.3	-164.3	-78.3	7.6	131.6
7:00	1553.7	1655.0	-101.3	-6.5%	$0.07	$0.06	72.9	-309.6	-186.5	-101.3	-16.1	107.0
8:00	1485.3	1605.6	-120.4	-8.1%	$0.06	$0.06	77.0	-330.5	-206.4	-120.4	-34.4	89.8
9:00	1358.1	1456.2	-98.2	-7.2%	$0.07	$0.12	82.3	-301.2	-181.3	-98.2	-15.1	104.9
10:00	1293.1	1319.4	-26.3	-2.0%	$0.09	$0.12	86.6	-223.8	-107.1	-26.3	54.5	171.2
11:00	1279.2	1268.5	10.7	0.8%	$0.14	$0.12	90.1	-187.3	-70.3	10.7	91.7	208.7
12:00	1231.4	1152.5	78.9	6.4%	$0.30	$0.12	92.6	-119.7	-2.4	78.9	160.2	277.6
13:00	1155.0	993.4	161.6	14.0%	$0.60	$0.27	93.9	-34.2	81.5	161.6	241.7	357.4
14:00	1096.7	940.9	155.8	14.2%	$0.97	$0.27	94.2	-39.7	75.8	155.8	235.9	351.4
15:00	1038.7	873.1	165.6	15.9%	$1.66	$0.27	93.1	-29.4	85.8	165.6	245.4	360.6
16:00	1002.8	850.0	152.8	15.2%	$2.37	$0.27	91.0	-42.2	73.0	152.8	232.6	347.8
17:00	984.2	824.7	159.6	16.2%	$3.27	$0.27	89.7	-35.6	79.7	159.6	239.4	354.8
18:00	955.8	791.1	164.7	17.2%	$3.26	$0.27	87.4	-30.9	84.7	164.7	244.7	360.3
19:00	971.4	829.7	141.7	14.6%	$2.46	$0.12	83.5	-208.7	-93.1	-13.0	67.1	182.7
20:00	987.0	868.3	118.8	12.0%	$1.55	$0.12	81.0	-77.5	38.5	118.8	199.1	315.0
21:00	1052.7	886.9	165.7	15.7%	$1.10	$0.12	79.2	-31.0	85.2	165.7	246.2	362.4
22:00	1056.6	958.9	97.7	9.2%	$1.22	$0.12	77.7	-98.2	17.5	97.7	177.8	293.5
23:00	1235.2	1038.1	197.1	16.0%	$0.26	$0.12	76.2	-4.2	114.7	197.1	279.4	398.4
0:00	1408.0	1321.4	86.6	6.2%	$0.10	$0.06	75.0	-117.2	3.2	86.6	170.0	290.5
	Reference Energy Use (kWh)	Energy Use with DR (kWh)	Change in Energy Use (kWh)	% Chage in Energy Use	Daily Average RTP Price	Daily Average OAT Price	Cooling Degree Hours (Base 70)	Uncertainty Adjusted Impact - Percentiles				
								10th	30th	50th	70th	90th
Daily	29,638.8	28,475.5	1,163.3	3.9%	$0.83	$0.13	272.0	176.8	759.6	1163.3	1566.9	2149.7

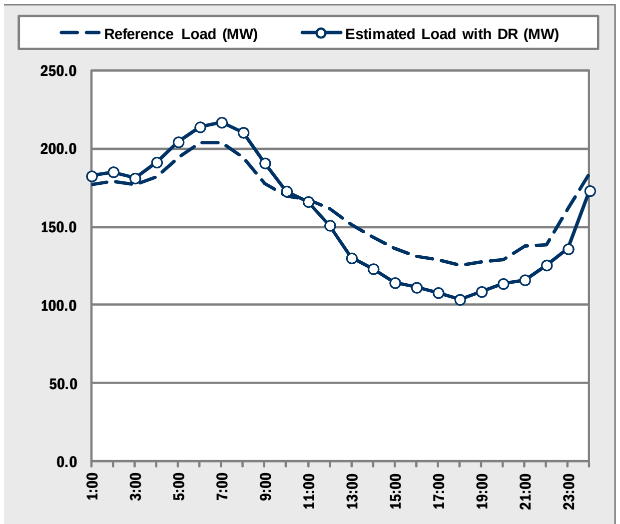
Figure 3-6:
Aggregate RTP Ex Post Load Impact (MW) for September 7, 2011

TABLE 1: Menu options

Type of Results	Aggregate
Month	September
Day Type	System Peak Day
Customer Characteristic	All Customers

TABLE 2: Output

RTP Rate Schedule	1. Extremely Hot Summer Weekday (>=95)
Date	Wednesday, September 07, 2011
Number of Accounts	131
Average Load Impact (MW) (1-6pm)	20.9
% Load Impact (1-6pm)	15.8%



Hour Ending	Reference Load (MW)	Estimated Load with DR (MW)	Load Impact (MW)	% Load Impact	RTP Price ($/kWh)	OAT Price ($/kWh)	Weighted Temp (F)	Uncertainty Adjusted Impact - Percentiles				
								10th	30th	50th	70th	90th
1:00	176.5	182.5	-6.0	-3.4%	$0.07	$0.06	73.7	-33.5	-17.2	-6.0	5.3	21.6
2:00	178.9	185.2	-6.3	-3.5%	$0.06	$0.06	72.6	-33.6	-17.4	-6.3	4.9	21.0
3:00	176.9	181.1	-4.2	-2.4%	$0.06	$0.06	71.2	-31.2	-15.2	-4.2	6.8	22.8
4:00	182.2	191.3	-9.1	-5.0%	$0.05	$0.06	70.4	-36.4	-20.3	-9.1	2.0	18.1
5:00	194.5	204.3	-9.8	-5.0%	$0.05	$0.06	70.2	-37.3	-21.0	-9.8	1.5	17.8
6:00	203.6	213.8	-10.3	-5.0%	$0.05	$0.06	70.5	-37.8	-21.5	-10.3	1.0	17.2
7:00	203.5	216.8	-13.3	-6.5%	$0.07	$0.06	72.9	-40.6	-24.4	-13.3	-2.1	14.0
8:00	194.6	210.3	-15.8	-8.1%	$0.06	$0.06	77.0	-43.3	-27.0	-15.8	-4.5	11.8
9:00	177.9	190.8	-12.9	-7.2%	$0.07	$0.12	82.3	-39.5	-23.7	-12.9	-2.0	13.7
10:00	169.4	172.8	-3.4	-2.0%	$0.09	$0.12	86.6	-29.3	-14.0	-3.4	7.1	22.4
11:00	167.6	166.2	1.4	0.8%	$0.14	$0.12	90.1	-24.5	-9.2	1.4	12.0	27.3
12:00	161.3	151.0	10.3	6.4%	$0.30	$0.12	92.6	-15.7	-0.3	10.3	21.0	36.4
13:00	151.3	130.1	21.2	14.0%	$0.60	$0.27	93.9	-4.5	10.7	21.2	31.7	46.8
14:00	143.7	123.3	20.4	14.2%	$0.97	$0.27	94.2	-5.2	9.9	20.4	30.9	46.0
15:00	136.1	114.4	21.7	15.9%	$1.66	$0.27	93.1	-3.8	11.2	21.7	32.1	47.2
16:00	131.4	111.4	20.0	15.2%	$2.37	$0.27	91.0	-5.5	9.6	20.0	30.5	45.6
17:00	128.9	108.0	20.9	16.2%	$3.27	$0.27	89.7	-4.7	10.4	20.9	31.4	46.5
18:00	125.2	103.6	21.6	17.2%	$3.26	$0.27	87.4	-4.0	11.1	21.6	32.1	47.2
19:00	127.3	108.7	18.6	14.6%	$2.46	$0.12	83.5	-27.3	-12.2	-1.7	8.8	23.9
20:00	129.3	113.7	15.6	12.0%	$1.55	$0.12	81.0	-10.2	5.0	15.6	26.1	41.3
21:00	137.9	116.2	21.7	15.7%	$1.10	$0.12	79.2	-4.1	11.2	21.7	32.3	47.5
22:00	138.4	125.6	12.8	9.2%	$1.22	$0.12	77.7	-12.9	2.3	12.8	23.3	38.4
23:00	161.8	136.0	25.8	16.0%	$0.26	$0.12	76.2	-0.5	15.0	25.8	36.6	52.2
0:00	184.5	173.1	11.3	6.2%	$0.10	$0.06	75.0	-15.4	0.4	11.3	22.3	38.1

	Reference Energy Use (MWh)	Energy Use with DR (MWh)	Change in Energy Use (MWh)	% Chage in Energy Use	Daily Average RTP Price	Daily Average OAT Price	Cooling Degree Hours (Base 70)	Uncertainty Adjusted Impact - Percentiles				
								10th	30th	50th	70th	90th
Daily	3,882.7	3,730.3	152.4	3.9%	$0.83	$0.13	272.0	23.2	99.5	152.4	205.3	281.6

Table 3-3 shows the average and aggregate ex post load impact estimates for the 1 PM to 6 PM window for each monthly system peak day in 2011.[7] The ex post impacts vary substantially as a function of the underlying RTP rates. For the monthly system peak days from December through March, the low cost winter weekday price schedule was in effect. When this price schedule was in effect, there was a small negative impact because RTP prices were relatively lower than the OAT from 1 PM to 6 PM compared to later in the day. Therefore, RTP customers shift a small amount of load to the 1 PM to 6 PM time period on low cost winter weekdays.

For the June system peak, the mild summer weekday price schedule was in effect. On this day, the load impact was negative because on-peak RTP prices were around $0.11/kWh versus $0.27/kWh on the OAT. As noted above, the RTP program produced a significant load reduction when it was needed most during the annual system peak day on September 7, when the average load reduction was around 159.7 kW per customer and 20.9 MW in aggregate, with a percent load impact of 15.8%.

Table 3-3:
2011 Average and Aggregate RTP Ex Post Load Impact Estimates
Monthly System Peak Days, On-Peak Period (1 PM to 6 PM)

Monthly System Peak Date	Price Schedule	Number of Customers	Avg. Reference Load (kW)	Avg. Load with DR (kW)	Avg. Load Reduction (kW)	Aggregate Load Reduction (MW)
1-Oct-10	6. High Cost Winter Weekday	90	1377.4	1216.4	161.0	14.5
4-Nov-10	6. High Cost Winter Weekday	90	1669.4	1508.3	161.0	14.5
13-Dec-10	7. Low Cost Winter Weekday	90	1307.3	1308.4	-1.1	-0.1
3-Jan-11	7. Low Cost Winter Weekday	94	1323.0	1324.1	-1.2	-0.1
22-Feb-11	7. Low Cost Winter Weekday	94	1499.2	1500.4	-1.2	-0.1
31-Mar-11	7. Low Cost Winter Weekday	94	1632.4	1636.5	-4.1	-0.4
1-Apr-11	6. High Cost Winter Weekday	94	1515.2	1360.9	154.3	14.5
4-May-11	6. High Cost Winter Weekday	94	1654.1	1499.8	154.3	14.5
27-Jun-11	5. Mild Summer Weekday	106	1263.3	1311.7	-48.3	-5.1
6-Jul-11	3. Hot Summer Weekday	128	1045.6	1007.0	38.5	4.9
26-Aug-11	3. Hot Summer Weekday	131	975.6	930.8	44.9	5.9
7-Sep-11	1. Extremely Hot Summer Weekday	131	1015.7	856.0	159.7	20.9

Table 3-4 shows the average and aggregate ex post load impact estimates for the 1 PM to 6 PM window on the average weekday for each month. The average weekday impacts depend on the frequency and mix of RTP price schedules within each month. From December 2010 to March 2011, the temperature in downtown LA did not rise above 90 degrees, so the low cost winter weekday price schedule was in effect for every weekday. As such, the load reduction was slightly negative on the average weekday for those months. In 2011, April and May had one and two high cost winter weekdays respectively, which resulted

[7] As in last year's evaluation, load data is only available through September of the evaluation year. Therefore, 2010 monthly system peak days are used for October through December.

in positive impacts for these months. The average weekday load reduction was largest in November 2010, which included two high cost winter weekdays. Although September had two extremely hot summer weekdays, the rest of the month was quite mild with price schedule 5 in effect on 50% of weekdays. This weather pattern resulted in small negative impact for the average weekday in September.

Table 3-4:
2011 Average and Aggregate RTP Ex Post Load Impact Estimates
Average Weekday by Month, On-Peak Period (1 PM to 6 PM)

Month	Number of Customers	Avg. Reference Load (kW)	Avg. Load with DR (kW)	Avg. Load Reduction (kW)	Aggregate Load Reduction (MW)
Oct-10	90	1384.6	1373.0	11.6	1.0
Nov-10	90	1568.8	1554.2	14.7	1.3
Dec-10	92	1356.7	1357.7	-1.0	-0.1
Jan-11	94	1392.3	1393.4	-1.2	-0.1
Feb-11	94	1476.3	1477.5	-1.2	-0.1
Mar-11	94	1585.8	1588.8	-2.9	-0.3
Apr-11	94	1521.0	1517.5	3.5	0.3
May-11	98	1550.8	1541.0	9.8	1.0
Jun-11	104	1349.9	1398.2	-48.3	-5.0
Jul-11	129	996.1	1015.6	-19.5	-2.5
Aug-11	131	982.2	993.4	-11.2	-1.5
Sep-11	131	978.0	985.0	-7.0	-0.9

3.4 RTP Ex Ante Load Impact Estimates

RTP grew from 101 to 131 accounts from September 2010 to September 2011. The program is expected to experience continued enrollment growth over the next few years because SCE plans to make the program available to C&I customers in the 200 kW to 500 kW range. In August 2013, RTP enrollment is expected to equal 173 participants and by December 2014, enrollment is expected to equal 298. Afterwards, enrollment is assumed to remain constant until the end of the ex ante forecast period (2022).

For ex ante purposes, load impacts for existing customers are not projected to change over the forecast horizon (2012-2022). However, new participants are expected to be relatively small compared to the average existing customer in the program. Therefore, load impacts for the two largest existing RTP customers are not included in the estimation of expected load reductions for new participants. These two large customers have average loads of over 25 MW and are unlikely to be representative of new participants.

Although removing the two largest customers from the estimation of load reductions for new participants will lead to a more conservative estimate, there are several unknown factors that could significantly change the result. For example, if all of the new participants come from the 200 kW to 500 kW category, the resulting aggregate load reduction will be considerably lower. On the other hand, if SCE is able to successfully market RTP and recruit more large customers over 25 MW, the resulting aggregate load reduction will be relatively higher. Considering that enrollment is expected to more than double over the next four years, there is a lot of uncertainty in the future load impacts. Nonetheless, the ex ante impacts presented here are the best estimates given the available data and provide a realistic benchmark for SCE to achieve.

The 1-in-2 and 1-in-10 system load conditions were matched with the RTP price schedules based on the prior day's maximum temperature in downtown LA. This approach was employed to accurately reflect the method for selecting the price schedule. Table 3-5 summarizes the price schedules in effect for each monthly system peak under 1-in-2 and 1-in-10 conditions. For summer monthly system peak days, price schedules with larger peak to off-peak price ratios are typically in effect. However, the price schedule with the strongest price signal does not always align with the monthly system peak.

Table 3-5:
RTP Price Schedule in Effect for each Ex Ante Monthly System Peak Day

Month	1-in-2 System Conditions	1-in-10 System Conditions
Jan	Low Cost Winter Weekday (90° F & below)	Low Cost Winter Weekday (90° F & below)
Feb	Low Cost Winter Weekday (90° F & below)	Low Cost Winter Weekday (90° F & below)
Mar	Low Cost Winter Weekday (90° F & below)	High Cost Winter Weekday (91° F & above)
Apr	Low Cost Winter Weekday (90° F & below)	Low Cost Winter Weekday (90° F & below)
May	Low Cost Winter Weekday (90° F & below)	High Cost Winter Weekday (91° F & above)
Jun	Mild Summer Weekday (80° F & below)	Extremely Hot Summer Weekday(95° F & above)
Jul	Hot Summer Weekday (85° to 90° F)	Hot Summer Weekday (85° to 90° F)
Aug	Very Hot Summer Weekday (91° to 94° F)	Extremely Hot Summer Weekday(95° F & above)
Sep	Extremely Hot Summer Weekday (95° F & above)	Extremely Hot Summer Weekday(95° F & above)
Oct	High Cost Winter Weekday (91° F & above)	High Cost Winter Weekday (91° F & above)
Nov	Low Cost Winter Weekday (90° F & below)	Low Cost Winter Weekday (90° F & below)
Dec	Low Cost Winter Weekday (90° F & below)	Low Cost Winter Weekday (90° F & below)

For the ex ante impact analysis, the RTP and OAT rates were assumed to remain similar to the most recently filed SCE tariffs. Figures 3-7 and 3-8 show the estimated reference load and the predicted load after customers respond to the RTP prices for the average customer on a typical event day based on 1-in-2 and 1-in-10 year weather conditions for the year 2015-2022. Impacts are reported for 2015-22 because enrollment growth reaches a steady state in 2015. As seen in the figures, for a 1-in-2 typical event day, the estimated load impact is 29.1 kW from 1 PM to 6 PM with an average price of $.38/kWh during the peak period. The load impact is 4.8% of the reference load. For the typical event day in a 1-in-10 weather year, prices and load impacts increase. The estimated load impact is 109 kW from 1 PM to

6 PM (17.9% of the reference load) with an average price of $2.29/kWh during the peak period. In a more extreme weather year, the high price schedules are more likely to be in effect, which results in higher load impacts for the 1-in-10 weather year.

The remainder of the hourly ex ante load impact estimates that are required by the protocols for RTP, including uncertainty adjusted estimates, can be found in the electronic appendix titled, “SCE 2011 RTP Ex-Ante Load Impact Tables.”

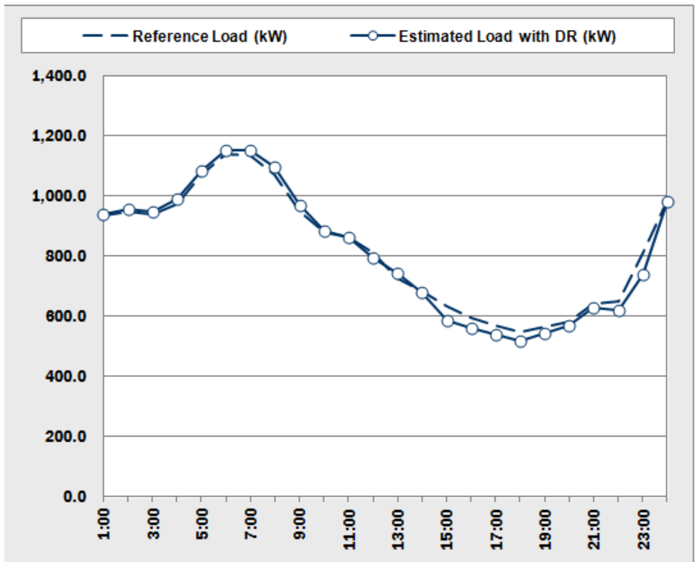
Figure 3-7:
RTP Average Load Impact (kW) per Customer for Years 2015-2022
for a Typical Event Day Based on 1-in-2 Year Weather Conditions

TABLE 1: Menu options

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

TABLE 2: Output

RTP Rate Schedule	3. Hot Summer Weekday (85-90)
Date	Thursday, January 24, 2002
Number of Accounts	298
Average Load Impact (kW) (1-6pm)	29.1
% Load Impact (1-6pm)	4.8%



Hour Ending	Reference Load (kW)	Estimated Load with DR (kW)	Load Impact (kW)	% Load Impact	RTP Price ($/kWh)	OAT Price ($/kWh)	Weighted Temp (F)	Uncertainty Adjusted Impact - Percentiles				
								10th	30th	50th	70th	90th
1:00	933.0	939.6	-6.7	-0.7%	$0.06	$0.06	68.6	-180.8	-77.9	-6.7	64.6	167.5
2:00	946.2	954.8	-8.7	-0.9%	$0.04	$0.06	67.4	-182.8	-79.9	-8.7	62.6	165.5
3:00	940.2	948.4	-8.3	-0.9%	$0.04	$0.06	66.2	-182.4	-79.5	-8.3	63.0	165.9
4:00	973.7	988.9	-15.2	-1.6%	$0.03	$0.06	65.6	-189.5	-86.5	-15.2	56.1	159.1
5:00	1070.3	1085.1	-14.7	-1.4%	$0.03	$0.06	64.8	-189.2	-86.1	-14.7	56.6	159.7
6:00	1137.3	1151.2	-13.9	-1.2%	$0.03	$0.06	64.1	-188.3	-85.3	-13.9	57.4	160.5
7:00	1133.3	1150.6	-17.2	-1.5%	$0.04	$0.06	64.5	-191.4	-88.5	-17.2	54.0	157.0
8:00	1068.5	1094.5	-26.0	-2.4%	$0.04	$0.06	68.1	-200.4	-97.4	-26.0	45.3	148.4
9:00	946.5	967.5	-21.0	-2.2%	$0.05	$0.12	73.7	-194.6	-92.0	-21.0	50.1	152.7
10:00	877.9	881.6	-3.7	-0.4%	$0.06	$0.12	78.6	-176.9	-74.6	-3.7	67.1	169.4
11:00	863.0	861.1	1.8	0.2%	$0.07	$0.12	82.8	-171.4	-69.1	1.8	72.7	175.0
12:00	811.8	791.6	20.1	2.5%	$0.10	$0.12	85.7	-153.3	-50.8	20.1	91.1	193.6
13:00	725.9	743.7	-17.7	-2.4%	$0.11	$0.27	87.9	-192.1	-89.1	-17.7	53.6	156.6
14:00	683.0	676.8	6.2	0.9%	$0.14	$0.27	89.6	-167.8	-65.0	6.2	77.4	180.2
15:00	632.4	586.1	46.3	7.3%	$0.29	$0.27	90.2	-127.3	-24.8	46.3	117.3	219.9
16:00	594.4	561.2	33.2	5.6%	$0.43	$0.27	90.3	-140.0	-37.6	33.2	104.1	206.4
17:00	567.0	539.2	27.8	4.9%	$0.53	$0.27	89.4	-145.4	-43.1	27.8	98.7	201.0
18:00	548.4	516.3	32.0	5.8%	$0.53	$0.27	87.2	-141.7	-39.0	32.0	103.1	205.7
19:00	564.9	542.2	22.7	4.0%	$0.37	$0.12	84.3	-150.5	-48.2	22.7	93.6	195.9
20:00	581.4	568.1	13.4	2.3%	$0.21	$0.12	80.6	-160.6	-57.8	13.4	84.6	187.4
21:00	639.6	628.7	10.9	1.7%	$0.16	$0.12	76.6	-164.5	-60.9	10.9	82.7	186.4
22:00	647.7	620.1	27.6	4.3%	$0.17	$0.12	74.4	-147.0	-43.8	27.6	99.0	202.2
23:00	811.5	739.4	72.1	8.9%	$0.08	$0.12	72.5	-102.5	0.6	72.1	143.5	246.7
0:00	984.1	979.2	5.0	0.5%	$0.08	$0.06	70.8	-168.8	-66.1	5.0	76.1	178.7

	Reference Energy Use (kWh)	Energy Use with DR (kWh)	Change in Energy Use (kWh)	% Chage in Energy Use	Daily Average RTP Price	Daily Average OAT Price	Cooling Degree Hours (Base 70)	Uncertainty Adjusted Impact - Percentiles				
								10th	30th	50th	70th	90th
Daily	19,681.9	19,516.0	166.0	0.8%	$0.15	$0.13	194.4	-686.3	-182.8	166.0	514.7	1018.2

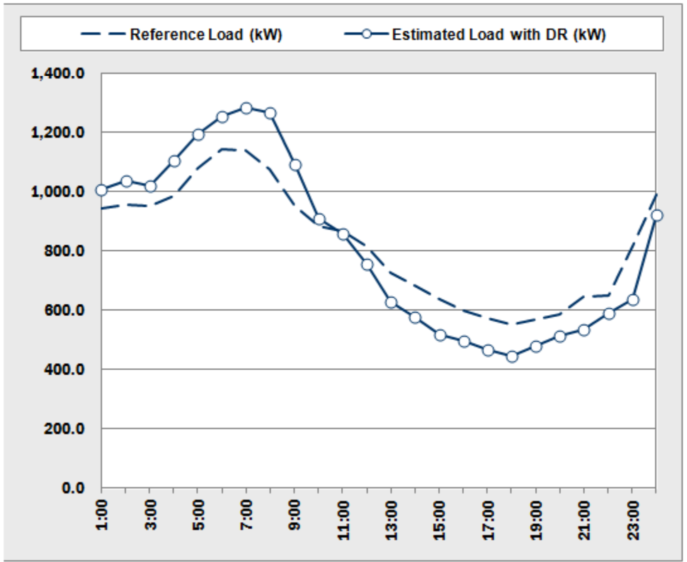
Figure 3-8:
RTP Average Load Impact (kW) per Customer for Years 2015-2022 for a Typical Event Day Based on 1-in-10 Year Weather Conditions

TABLE 1: Menu options

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

TABLE 2: Output

RTP Rate Schedule	1. Extremely Hot Summer Weekday (>=95)
Date	Tuesday, February 01, 2000
Number of Accounts	298
Average Load Impact (kW) (1-6pm)	109.0
% Load Impact (1-6pm)	17.9%



Hour Ending	Reference Load (kW)	Estimated Load with DR (kW)	Load Impact (kW)	% Load Impact	RTP Price ($/kWh)	OAT Price ($/kWh)	Weighted Temp (F)	Uncertainty Adjusted Impact - Percentiles 10th	30th	50th	70th	90th
1:00	942.7	1005.7	-63.1	-6.7%	$0.06	$0.06	75.2	-262.6	-144.7	-63.1	18.5	136.4
2:00	957.3	1035.1	-77.8	-8.1%	$0.04	$0.06	74.0	-282.6	-161.6	-77.8	6.1	127.1
3:00	952.6	1019.0	-66.4	-7.0%	$0.04	$0.06	73.1	-270.6	-150.0	-66.4	17.2	137.8
4:00	985.4	1104.9	-119.6	-12.1%	$0.03	$0.06	72.3	-331.6	-206.4	-119.6	-32.8	92.5
5:00	1078.7	1194.4	-115.7	-10.7%	$0.03	$0.06	71.7	-333.9	-205.0	-115.7	-26.4	102.5
6:00	1144.1	1253.9	-109.8	-9.6%	$0.04	$0.06	71.4	-323.1	-197.1	-109.8	-22.5	103.5
7:00	1139.9	1282.6	-142.6	-12.5%	$0.05	$0.06	71.6	-345.8	-225.8	-142.6	-59.5	60.5
8:00	1075.7	1264.1	-188.3	-17.5%	$0.04	$0.06	74.2	-398.7	-274.4	-188.3	-102.2	22.1
9:00	952.4	1089.8	-137.4	-14.4%	$0.05	$0.12	78.5	-327.4	-215.1	-137.4	-59.6	52.7
10:00	881.9	908.0	-26.1	-3.0%	$0.07	$0.12	82.4	-202.7	-98.4	-26.1	46.1	150.5
11:00	865.6	857.4	8.2	0.9%	$0.13	$0.12	85.6	-167.9	-63.8	8.2	80.3	184.3
12:00	816.1	756.8	59.3	7.3%	$0.28	$0.12	87.9	-116.4	-12.6	59.3	131.2	235.0
13:00	726.5	628.3	98.2	13.5%	$0.59	$0.27	89.8	-75.9	26.9	98.2	169.4	272.2
14:00	682.4	574.8	107.5	15.8%	$0.95	$0.27	91.3	-66.5	36.3	107.5	178.7	281.6
15:00	637.7	519.0	118.7	18.6%	$1.64	$0.27	91.7	-54.9	47.7	118.7	189.8	292.4
16:00	598.9	494.3	104.6	17.5%	$2.35	$0.27	91.3	-69.1	33.5	104.6	175.7	278.3
17:00	572.1	466.9	105.2	18.4%	$3.25	$0.27	90.1	-68.6	34.1	105.2	176.3	279.0
18:00	553.1	444.0	109.2	19.7%	$3.24	$0.27	87.9	-64.9	38.0	109.2	180.4	283.2
19:00	569.5	479.5	90.0	15.8%	$2.44	$0.12	84.8	-84.1	18.8	90.0	161.2	264.1
20:00	585.9	515.0	70.9	12.1%	$1.53	$0.12	80.8	-103.8	-0.6	70.9	142.3	245.5
21:00	642.9	536.1	106.7	16.6%	$1.08	$0.12	77.5	-68.6	35.0	106.7	178.4	282.0
22:00	650.1	587.8	62.3	9.6%	$1.20	$0.12	75.6	-111.8	-9.0	62.3	133.5	236.4
23:00	815.5	638.3	177.2	21.7%	$0.24	$0.12	74.1	-3.1	103.5	177.2	251.0	357.5
0:00	987.7	921.4	66.3	6.7%	$0.08	$0.06	73.1	-120.2	-10.0	66.3	142.6	252.9

	Reference Energy Use (kWh)	Energy Use with DR (kWh)	Change in Energy Use (kWh)	% Chage in Energy Use	Daily Average RTP Price	Daily Average OAT Price	Cooling Degree Hours (Base 70)	Uncertainty Adjusted Impact - Percentiles 10th	30th	50th	70th	90th
Daily	19,814.9	19,577.4	237.5	1.2%	$0.81	$0.13	245.6	-682.8	-139.1	237.5	614.0	1157.7

Table 3-6 shows the aggregate on-peak RTP ex ante load impacts for each monthly system peak day by weather year and forecast year. In accordance with the revised resource adequacy hours, the peak period is defined as 1 PM to 6 PM from April through October and 4 PM to 9 PM from November through March. Because RTP impacts are driven entirely by the daily price schedule, they depend highly on the previous day's temperature in downtown LA. In some cases, peak system conditions occur following a relatively cool day, as can be seen for July during a 1-in-10 weather year and June under 1-in-2 weather conditions. In particular, the system peak for June under 1-in-2 conditions occurs on a day with the mild summer weekday price schedule, so load impacts are negative.

Once enrollment steadies in December 2014, the program is expected to be capable of delivering 32.5 MW of load reduction on extremely hot summer weekdays, which occur during September under 1-in-2 system conditions and June, August and September in a 1-in-10 weather year (highlighted in the table). SCE system load typically peaks during August and September. For these monthly peaks in a 1-in-2 and 1-in-10 weather year, aggregate impacts are expected to double from 2012 to 2015 as a result of new enrollment.

Table 3-6:
RTP Aggregate On-Peak Load Impacts (MW)
for each Monthly System Peak Day by Weather Year and Forecast Year
(Extremely Hot Summer Weekdays are Highlighted)

Weather Year	Month	Peak Period	2012	2013	2014	2015-2022
1-in-2	Jan	4-9 PM	-0.7	-0.9	-1.2	-1.6
	Feb	4-9 PM	-0.7	-0.9	-1.2	-1.6
	Mar	4-9 PM	-1.5	-2.0	-2.6	-3.2
	Apr	1-6 PM	-0.3	-0.4	-0.6	-0.7
	May	1-6 PM	-0.3	-0.4	-0.6	-0.7
	Jun	1-6 PM	-6.0	-6.7	-7.7	-8.3
	Jul	1-6 PM	5.6	6.6	8.0	8.7
	Aug	1-6 PM	17.0	19.2	22.2	23.5
	Sep	**1-6 PM**	**22.6**	**26.2**	**31.1**	**32.5**
	Oct	1-6 PM	14.8	16.6	19.0	19.5
	Nov	4-9 PM	-0.9	-1.2	-1.5	-1.6
	Dec	4-9 PM	-0.9	-1.2	-1.6	-1.6
1-in-10	Jan	4-9 PM	-0.7	-0.9	-1.2	-1.6
	Feb	4-9 PM	-0.7	-0.9	-1.2	-1.6
	Mar	4-9 PM	12.7	13.9	15.4	16.8
	Apr	1-6 PM	-0.3	-0.4	-0.6	-0.7
	May	1-6 PM	14.2	15.8	17.9	19.5
	Jun	**1-6 PM**	**21.9**	**25.2**	**29.7**	**32.5**
	Jul	1-6 PM	5.6	6.6	8.0	8.7
	Aug	**1-6 PM**	**22.4**	**25.9**	**30.6**	**32.5**
	Sep	**1-6 PM**	**22.6**	**26.2**	**31.1**	**32.5**
	Oct	1-6 PM	17.4	16.6	19.0	19.5
	Nov	4-9 PM	-0.9	-1.2	-1.5	-1.6
	Dec	4-9 PM	-0.9	-1.2	-1.6	-1.6

Table 3-7 shows the aggregate on-peak RTP ex ante load impacts for each monthly average weekday by weather year and forecast year. As noted above, in accordance with the revised resource adequacy hours, the peak period is defined as 1 PM to 6 PM from April through October and 4 PM to 9 PM from November through March. The 1-in-2 load impacts do not vary substantially because the average hourly RTP price is not significantly different from the OAT for the average weekday in a normal weather year. From 2015 to 2022, the 1-in-2 aggregate impacts are mostly negative, ranging from -8.3 MW in July, to -0.7 MW in April, May and October. In a 1-in-10 weather year, average weekday aggregate impacts are as high as 8.2 MW in August 2015-2022.

Table 3-7:
RTP Aggregate On-Peak Load Impacts (MW)
for each Monthly Average Weekday by Weather Year and Forecast Year

Weather Year	Month	Peak Period	2012	2013	2014	2015-2022
1-in-2	Jan	4-9 PM	-0.7	-0.9	-1.2	-1.6
	Feb	4-9 PM	-0.7	-0.9	-1.2	-1.6
	Mar	4-9 PM	-1.5	-2.0	-2.6	-3.2
	Apr	1-6 PM	-0.3	-0.4	-0.6	-0.7
	May	1-6 PM	-0.3	-0.4	-0.6	-0.7
	Jun	1-6 PM	-6.0	-6.7	-7.7	-8.3
	Jul	1-6 PM	-3.9	-4.6	-5.6	-6.1
	Aug	1-6 PM	-3.9	-4.5	-5.2	-5.4
	Sep	1-6 PM	-4.0	-4.6	-5.4	-5.7
	Oct	1-6 PM	-0.3	-0.4	-0.4	-0.4
	Nov	4-9 PM	-0.9	-1.2	-1.5	-1.6
	Dec	4-9 PM	-0.9	-1.2	-1.6	-1.6
1-in-10	Jan	4-9 PM	-0.7	-0.9	-1.2	-1.6
	Feb	4-9 PM	-0.7	-0.9	-1.2	-1.6
	Mar	4-9 PM	-1.5	-1.7	-1.8	-2.0
	Apr	1-6 PM	-0.3	-0.4	-0.6	-0.7
	May	1-6 PM	-0.3	-0.3	-0.4	-0.4
	Jun	1-6 PM	-3.9	-4.5	-5.3	-5.8
	Jul	1-6 PM	-3.9	-4.6	-5.6	-6.1
	Aug	1-6 PM	5.7	6.5	7.7	8.2
	Sep	1-6 PM	5.7	6.6	7.9	8.2
	Oct	1-6 PM	-0.3	-0.3	-0.4	-0.4
	Nov	4-9 PM	-0.9	-1.2	-1.5	-1.6
	Dec	4-9 PM	-0.9	-1.2	-1.6	-1.6

3.5 Recommendations

As discussed in Section 3.4, future aggregate load impacts are closely tied to the size of new participants relative to the existing population. If all of the new participants come from the 200 kW to 500 kW category, the resulting aggregate load reduction will be relatively lower. On the other hand, if SCE is able to successfully market RTP and recruit more large customers, the resulting aggregate load reduction will be relatively higher. It is important that SCE continues to market RTP to large customers and not just focus on the 200 kW to 500 kW segment.

As discussed in previous year's evaluations, the program would also likely benefit from an analysis of how to further optimize price schedule selection. The schedules are currently selected based on downtown LA daily maximum temperatures on the previous day. The current rule is transparent and easy for participants to understand and track, but may not always target load impacts to time periods when they are most needed. Based on our extensive collective experience modeling system load and individual customer loads, the main difference between high and extreme system loads is not daily maximum temperature, but rather overnight heat build-up. We recommend assessing the incremental improvement of different pricing schedule selection rules and the associated tradeoffs, including the effect on transparency and clarity.