Electricity Demand Forecast Forms

California Energy Commission 2009 Integrated Energy Policy Report Docket Number 09-IEP-1C

Form 4

SCE Retail Sales, Energy and Demand Forecast Methodology

SOUTHERN CALIFORNIA EDISON®

An EDISON INTERNATIONAL® Company

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California Energy Commission
Docket Office
1516 Ninth Street, MS-4
Sacramento, CA 95814-5512

Attention: **Docket 09-IEP-1C**

Dear Docket Office:

Southern California Edison Company appreciates the opportunity to submit Demand Forms for the 2009 IEPR.

Should you have any questions, please do not hesitate to contact me at (916) 441-2369.

Sincerely,

/s/ Manuel Alvarez
Manuel Alvarez
Manager, Regulatory Policy & Affairs

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1) Introduction

SCE uses econometric models to forecast monthly retail electricity sales (billed recorded sales measured at customer meters) by customer class. Retail sales are final sales to both bundled and direct access customers within the SCE service territory. It excludes sales to public power customers, contractual sales, or inter-changes with other utilities. CCA and other departed load are not part of the forecast process, at this time.

The retail sales forecast represents the sum of sales in seven customer classes: residential, commercial, industrial, other public authority, agriculture, street lighting and inter-department transfers (IDT). Each customer class forecast (with the exception of IDT) is itself the product of two separate forecasts: a forecast of electricity consumption per customer or building square foot and a forecast of the number of customers or total building square feet. The forecast of IDT sales, which represents a very small percentage of total retail sales, is based upon a simple average of recorded monthly sales that occurred over the most recent 14 month period. Customer class data are used because they have been defined in a consistent manner throughout the sample period used in the econometric estimation.

The electricity consumption per customer or per square foot forecasts are produced by statistical models that are based upon measured historical relationships between electricity consumption and various economic and demographic factors that are thought to influence electricity consumption. The typical estimation procedure used to construct these statistical models is ordinary least squares (OLS). Another set of econometric equations are used to forecast customers by customer class, with the exception of residential customers. Residential customers are forecast using a stock adjustment model that transforms housing starts into new customer additions taking into consideration vacancy rates and demolition rates (more detail is provided in Section 9 below).

The regression equations, along with forecasts of the economic drivers provided principally by Global Insight and McGraw-Hill, and normal weather conditions and normal billing days, are used to predict sales by revenue class. Model-generated forecasts may be modified based on current trends, judgment, and events that are not specifically modeled in the equations.

As indicated, retail sales include sales to both bundled and Direct Access (DA) customers. DA customers accounted for 9,300 GWh of sales in 2007 (about 10.5 percent of retail sales). This sales level is assumed to remain approximately constant throughout the forecast. DA sales are subtracted from the retail sales forecast in order to derive to the forecast of SCE bundled customer sales. Bundled energy at the ISO settlement point is then derived by adjusting the annual bundled sales forecast for distribution losses.

2) Forecast Assumptions and Drivers

The underlying assumptions regarding the economy, weather, electricity prices, conservation and self-generation are all significant factors affecting the sales forecast. Each of these important variables is discussed briefly below:

Employment Growth in Southern California

Employment growth in Southern California has slowed considerably over the past two years. As of March 2008, the year over year percent change in total Non-Farm employment growth was -0.7 percent. Peak employment growth during the current expansion phase of the business cycle occurred in February 2006, when year over year growth in Non-Farm employment reached 2.7 percent.

A major reason for the slowing employment growth trend in Southern California is the downturn in residential housing construction. During the peak of the Southern California housing boom, year over year construction employment was growing at double-digit rates, but starting In February 2007, construction employment started to contract significantly. Also negatively affected by the housing construction slowdown is Financial Services employment. Between 2001 and 2005 Financial Service employment growth in Southern California averaged nearly 4 percent per year. However, recent data suggests that year over year Financial Service employment is contracting at a rate of -6.0 percent.

As a consequence, Commercial Service employment growth as a whole has slowed dramatically over the past year. Year over year growth in service employment was in the 2 percent range as recently as January 2007, but by March 2008, commercial service employment growth was at a standstill – showing zero growth between January and March 2008. The only sectors that have maintained relatively strong employment growth up to March of this year include Education and Health Care and Government.

According to Global Insight, total non-farm employment growth will remain around zero in 2008 and 2008. In the key sectors that most directly impact future retail electricity sales, we are forecasting 0.4 percent annual growth for Commercial Services in 2008 and 2.4 percent average annual growth in 2009. Job losses are expected to continue in the Southern California manufacturing sector – about a one percent decline per year in each of 2008 and 2009. These projections are similar to the declines in manufacturing employment experienced in 2004 to 2006. Finally, Government employment growth is expected to average about one percent per year between 2006 and 2009, which is about equal to Government employment growth in 2006.

We use employment per square foot to explain how electricity consumption varies in response to changing economic conditions. It turns out that a change in employment per square foot is an important source of explanatory power in measuring and predicting variation in electricity consumption. The assumption is that an increase in the number employed per square foot increases electricity use because an increase in employment is associated with an increase in energy using office and factory machines and equipment.

Changes in employment per square foot cause both seasonal variations in electricity consumption and changes in the longer term trend rate of growth in consumption over the forecast period.

Weather

SCE uses 30 year average temperature conditions as its definition of normal weather. Normal weather conditions are assumed throughout the forecast period. For purposes of model estimation and forecasting, actual and normal temperature data are transformed into cooling and heating degree days. Since normal weather is assumed throughout the forecast, weather variation generates a seasonal pattern to electricity use but has only a small influence on trend growth. More detail on weather normalization is provided in Section 4 below.

Billing Days

The number of days for which a customer is billed can vary depending upon meter reading schedules. Recorded sales will therefore vary with the number of billing days. The average number of billing days in a month turns out to be a very important source of explanatory power in all the electricity use models. For purposes of the forecast, we assume the historical average number of billing days in each month. Like weather, billing days provides variation in use over the months in a year, but does not contribute to trend growth in electricity consumption.

Electricity Prices

It is typically difficult to estimate a statistically significant relationship between changes in electricity consumption and changes in electricity prices. There are a number of reasons for this. First, electricity prices are regulated and therefore may vary only infrequently. Second, price signals between electric utilities and consumers can be obscured by lags in the transmission of price information and the complexities inherent in tariff structures. We attempt to simplify these issues by using an average unit revenue price with a one period lag (with the exception of the industrial electricity consumption model, which does use current period rates). Finally, electricity consumption is considered to be a necessity good, which means that consumption is relatively unresponsive to changes in price, at least in the short-run. In other words short-run elasticities are generally -.1 or smaller.

Electricity Conservation Programs

Energy efficiency programs are grouped into two categories: energy efficiency and demand reduction. The energy efficiency programs described below join the existing SCE conservation efforts. The quantification of energy savings from the existing programs are based upon approved expenditures for Demand-Side Management (DSM). The historical savings for these are taken from the Annual DSM Summary Reports (March 31 Report).

Two sources for future energy efficiency savings are used in the Spring 2008 Forecast. Energy efficiency savings for 2007 through 2008 are taken from the Final 2006-2008 Energy Efficiency Program Plans And Program Solicitation Selections submitted to the CPUC by the Demand Planning and Integration Group within the Customer Services Business Unit. For 2009, Demand Planning and Integration Group developed an energy savings forecast based on the maximum reliably-achievable potential (MRAP) within the SCE service territory. The maximum reliably-achievable potential is based on a SCE-specific version of the statewide energy efficiency potential study performed by Itron and KEMA completed in May 2006. Itron and KEMA developed the SCE 2006 forecast of MRAP in close coordination with Demand Planning and Integration Group staff. The methodology used in the development of SCE 2006 forecast of MRAP is described in California Energy Efficiency Potential Study, May 2006 and the Southern California Edison's Energy Efficiency Potential Study 2006. These reports can be accessed on the web at 'calmac.org'

The MRAP results are mapped into six forecast categories for use in the sales forecast by the Demand Planning and Integration Unit.

Mapping of MRAP into Forecast Categories

MRAP FORECAST	2006	2007	2008	2009	2010
Net GWh					
Residential Retrofit	285	459	507	424	418
Commercial Retrofit	292	455	465	371	356
Industrial Retrofit	113	198	251	202	144
Residential New Construction	1	2	3	3	3
Commercial New Construction	32	41	49	44	47
Industrial New Construction	6	8	9	7	7
TOTAL	730	1163	1285	1051	975

The forecast annual and monthly energy efficiency savings are provided in Excel file 'Energy Efficiency Summary.xls'. The monthly energy efficiency savings are estimated by distributing the annual savings using hourly load shapes based on the historical hourly energy data starting in1998. The hourly data is aggregated into monthly data. Please note the differences between the sum of the incremental energy efficiency savings and the cumulated energy efficiency savings are represented by estimated program decay. Program decay reflects instances where efficient appliances or measures are not replaced by similarly or more efficient appliances or measures. Replacement by similarly efficient appliances or measures is represented by efficiency persistence.

The demand reduction programs include multiple load control programs. The programs include I6, Residential A/C Cycling, Commercial A/C Cycling and various demand bidding programs. Together this will reduce demand by 650 MW. The impacts of these programs are reported as resources in the SCE resource plan.

Real Income

Real income serves much the same purpose in the residential electricity consumption model that employment does in the commercial and industrial electricity consumption models: Changes in real income per capita explain a significant amount of the variation in residential electricity consumption that is due to changes in economic conditions. This was particularly true during the 2000 to 2006 period – a period of economic contraction and recovery.

Self Generation

The forecast of bypass co-generation is calculated from two lists of customers operating generating systems interconnected to the grid for the purpose of meeting their own energy requirements: a thermal list and a solar list. Both lists consists those having systems on-line, under construction or current plans to install. The description of each facility includes designation of customer class, nameplate capacity in kilowatts (KW), probable bypass KW, capacity factor and on-line date. Separate forecasts are developed for thermal and solar/renewable systems and then combined for use in the sale forecast. There are approximately 550 operational thermal systems ranging in size from 1KW to 76 Megawatts (MW) within the SCE service area. The forecast for 2008 includes generation facilities currently in the pipeline while 2009 assumes the installations will mirror the historical trend. Twenty-nine MW are added in 2008 and 25 MW in 2009.

There are approximately 4,300 operational solar systems ranging in size from 1KW to 630 KW within the SCE service area. The forecast for 2008 includes solar facilities currently in the pipeline. The projection of solar bypass for the 2009 is based on the target set in the California Solar Initiative (CSI).

Both lists are used to estimate annual energy production which is then allocated to the months. For the thermal generation, the annual energy is calculated using the bypass capacity and a high capacity factor for all hours of the year. The annual energy is distributed to the months using a thermal load shape based on typical TOU-8 customer load shape, modified to be fully online during the on-peak periods from June into October of each year. The hourly loads are summed for each month to provided a monthly thermal parameter used in the sales forecasting models.

For the solar generation, the annual energy, for the historical period is calculated using the bypass capacity and an annual capacity factor for all hours of the year. For the post 2007 the capacity and energy are taken directly from the 2006 LTPP. The annual energy is distributed to the months using monthly capacity factors taken from the CPUC Self-Generation Incentive Program, Fifth Year Impact Evaluation, Draft-Final Report prepared by in February 2007 by Itron for PG&E and the Self-Generation Incentive Working Group.

3) Historic Forecast Performance

SCE examines model statistics as one aspect of assessing forecast reasonableness. If the model statistics suggest a well specified model and estimated parameters conform to economic theory, we place some degree of confidence that the model will produce a reasonable forecast. For example, we generally accept a statistical relationship between electricity use and a variable thought to influence it only if the estimated parameter is at least twice the magnitude of its standard error. Also, we compare elasticities derived from the model and compare these to elasticities published in various studies or reported by other utilities.

We also perform in-sample simulations. That is, we test the models forecast performance over a period of time where simulated electricity use can be compared to actual electricity use.

Our forecasts are regularly and constantly evaluated with respect to accuracy. The basic evaluation is straightforward: the forecast prediction for a particular time period is compared to actual data, adjusted for weather variation. as that data becomes available.

The basic metrics used in the evaluation are the Root Mean Squared Error (RMSE) and the Mean Absolute Percent Error (MAPE).

The definitions of RMSE and MAPE are as follows:

Suppose the forecast sample is j = T + 1, T + 2, …,T + *h*
Let $S_{F,t}$ represent predicted sales in period t and $S_{N,t}$ represent actual adjusted sales in period t; then:

$$\text{RMSE} = \text{SQRT}\left(\sum_{t=T+1} (S_{F,t} - S_{N,t})^2 / h \right)$$

$$\text{MAPE} = 100 \bullet \sum_{t=T+1} \text{ABS}((S_{F,t} - S_{N,t}) / S_{N,t}) / h$$

The validation process with respect to the Long Term Sales forecast is undertaken monthly as each successive month's actual billed sales becomes available. As part of the validation process, the new month's billed sales is converted into weather and billing day adjusted values in order to eliminate variation in weather and billing days from the evaluation calculations.

4) Weather Adjustment Procedures

SCE has developed the weather and billing cycle adjustment model for the purpose of comparing recorded and weather adjusted sales on a monthly basis. Weather and the calendar have the most significant impact on the monthly and annual variations in electricity sales. The Weather Modeling System (WMS) is a SAS based program that calculates heating- and cooling-degree days (HDD/CDD) that correspond to the monthly billing cycle schedule rather then a calendar month. The weather stations used in the model include Pomona-Ontario, Palm Springs, Long Beach, Riverside, San Gabriel, Santa Ana, Oxnard, Fresno, Lancaster and Los Angeles International Airport. The maximum and minimum temperature for each station is recorded for use in the WMS.

The annual billing cycle consists of 12 schedules of 21 meter reading days distributed across the year. A monthly billing cycle consists of 21 meter read days. The 12 monthly billing cycles while approximating a calendar month are not required to be contiguous with the calendar month. In addition the number of days for between each meter read varies depending on the days in the month and the number of weekend days and holidays. The MWS, using daily temperatures and the number of days between each meter read, calculates the number of HDD/CDD for the 252 (12 x 21) meter read days in a year.

The electricity sales for each monthly billing cycle are decomposed into the each meter read. The electricity sales for the meter reads are statistically adjusted as a function of the difference between actual HDD/CDD for recorded number of days in the meter read. The adjusted electricity sales are then aggregated back into a monthly billing cycle.

The HDD are calculated using 65 degrees while CDD are calculated using 70 degrees. Using 70 degrees for calculating CDD more closely approximates the temperature at which air conditioning is a factor.

The HDD/CDD is also adjusted for the changing distribution of customers within the service area. The WMS calculates customer-weighted average HDD/CDD using daily temperatures for the ten weather stations listed above. A further refinement is that the HDD/CDD are also adjusted according to the changing saturation of space conditioning appliances. Finally, separate sets of HDD/CDD are calculated for residential and non-residential electricity sales. A corresponding set of normal HDD/CCD, based on thirty years of history (1974 to 2003) are also calculated in the same manner.

The weather and billing day adjustment process is as follows:

Let $Y_{A,t}$ = actual billed sales per customer and $Y_{N,t}$ = adjusted sales per customer

Then $Y_{At} = \beta_0 + \beta_1 \bullet CDD_{A,t} + \beta_2 \bullet BDays_{A,t}$ and

$$Y_{Nt} = \beta_0 + \beta_1 \bullet CDD_{N,t} + \beta_2 \bullet BDays_{N,t}$$

Where $CDD_{A,t}$ is actual measured cooling degree days in the current time period, $BDays_{A,t}$ is actual measured billing days in the current time period, $CDD_{N,t}$ is normal cooling degree days and $BDays_{N,t}$ is normal billing days; β_1 and β_2 are coefficients that measure the relationship between a change in CDD and BDays respectively and a change in sales per customer.

The weather adjustment is:

$W_t = (Y_{A,t} – Y_{N,t}) \bullet Cust_t$ and Weather Adjusted sales are: $S_{N,t} = S_{A,t} – W_t$

5) Forecast Uncertainty

Suppose the "true" regression model is given by:

$$Y_t = x_t' ß + e_t$$

where e_t is an independent, and identically distributed, mean zero random disturbance, and ß is a vector of unknown parameters. The true model generating Y is not known, but we obtain estimates b of the unknown parameters .Then, setting the error term equal to its mean value of zero, the (point) forecasts of Y are obtained as:

$$y_t = x_t' b$$

Forecasts are made with error, where the error is simply the difference between the actual and forecasted value:

$$e_t = y_t - x_t' b$$

Assuming that the model is correctly specified, there are two sources of forecast error: residual uncertainty and coefficient uncertainty.

Residual Uncertainty

The first source of error, termed residual or innovation uncertainty, arises because the innovations e in the equation are unknown for the forecast period and are replaced with their expectations. While the residuals are zero in expected value, the individual values are non-zero; the larger the variation in the individual errors, the greater the overall error in the forecasts.

The standard measure of this variation is the standard error of the regression. Residual uncertainty is usually the largest source of forecast error.

Coefficient Uncertainty

The second source of forecast error is coefficient uncertainty. The estimated coefficients b of the equation deviate from the true coefficients ß in a random fashion. The standard error of the estimated coefficient, given in the regression output, is a measure of the precision with which the estimated coefficients measure the true coefficients.

The effect of coefficient uncertainty depends upon the exogenous variables. Since the estimated coefficients are multiplied by the exogenous variables in the computation of forecasts, the more the exogenous variables deviate from their mean values, the greater is the forecast uncertainty.

Forecast Variability

The variability of forecasts is measured by the forecast standard errors. For a single equation without lagged dependent variables or ARMA terms, the forecast standard errors are computed as:

$$se = s \sqrt{1 + x_t' (X'X)^{-1} x_t}$$

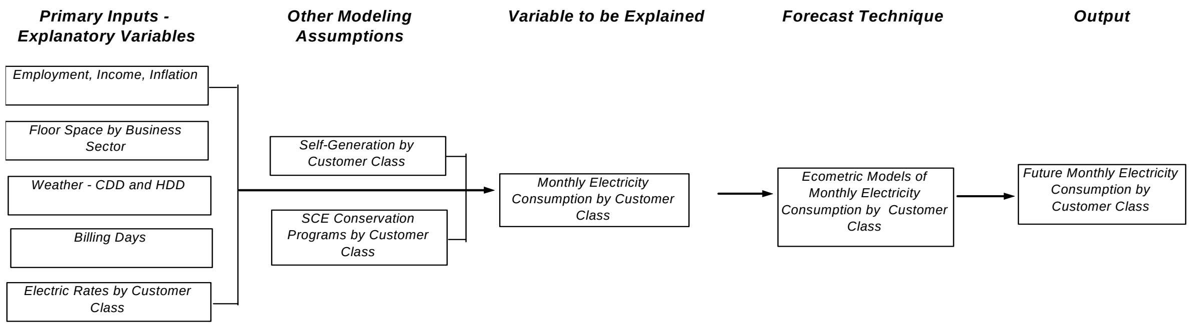
where s is the standard error of regression. These standard errors account for both innovation uncertainty (the first term) and coefficient uncertainty (the second term). Point forecasts made from linear regression models estimated by least squares are optimal in the sense that they have the smallest forecast variance among forecasts made by linear unbiased estimators. Moreover, if the innovations are normally distributed, the forecast errors have a t-distribution and forecast intervals can be readily formed. A two standard error band provides an approximate 95% forecast interval. In other words, if you (hypothetically) make many forecasts, the actual value of the dependent variable will fall inside these bounds 95 percent of the time. SCE constructs 95% confidence bands around its base case forecast based on the uncertainties described above.

Exogenous Variable Uncertainty

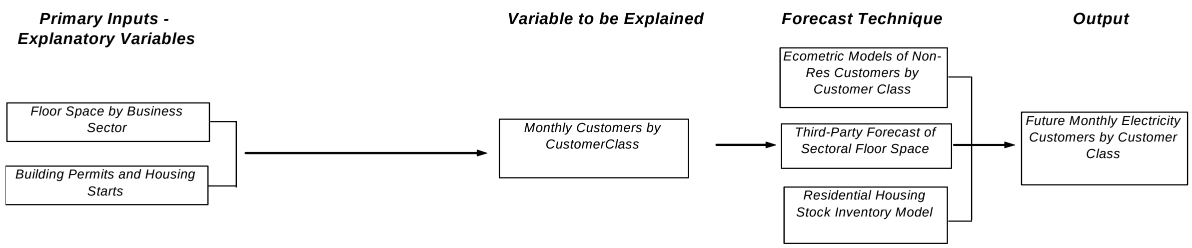
Exogenous variable uncertainty, i.e., uncertainty regarding future weather conditions, economic conditions, etc. is handled through the construction of forecast scenarios. For example, we typically include along with a base case forecast, high and low weather condition forecasts, as well as alternative high and low economic case forecasts.

6) Flow Diagram for Electric Use and Customer Modeling and Forecasting

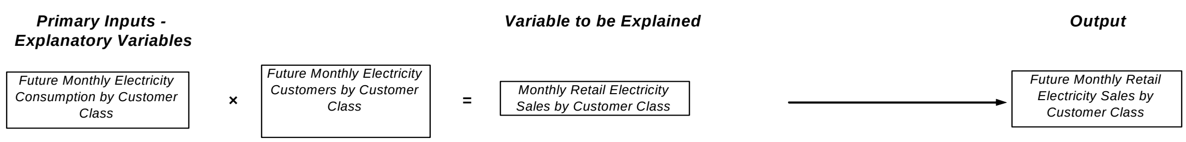
Electricity Consumption (kWh per Customer) Modeling and Forecasting



Electric Customer Modeling and Forecasting



Retail Sales Modeling and Forecasting



Note: Customer Classes = Residential, Commercial, Industrial, Other Public Authority, Agriculture, Streelighting.

7) Model Statistics – Electricity Use Models

The statistical details of the electricity consumption models are shown below. A glossary of variable names follows in Section 8.

Residential Electricity Use Model

Dependent Variable: RESUSE+RESPROG
Method: Least Squares
Sample (adjusted): 1991M02 2008M04
Included observations: 207 after adjustments

Variable	***Coefficient***	***Std. Error***	***t-Statistic***	***Prob.***
INTERCEPT	-87.26951	52.87946	-1.650348	0.1005
CDDY*SUMSEAS*HSLDSIZE	0.000301	5.09E-06	59.08728	0.0000
HDDY*WINSEAS*HSLDSIZE	0.000147	6.54E-06	22.45713	0.0000
BDAYS	0.912718	0.036714	24.86026	0.0000
RESRATE(-1)*CRISIS	-9.774572	1.758532	-5.558369	0.0000
RESRATE(-1)*NOCRISIS	-8.065795	1.848495	-4.363438	0.0000
RYPRPOP	0.002982	0.001002	2.975319	0.0033
WEALTH	12.45206	1.405031	8.862485	0.0000
MAR	-15.85943	4.207572	-3.769260	0.0002
APR	19.92363	4.455813	4.471379	0.0000
NOV	12.86513	4.185833	3.073494	0.0024
B0798	-42.12440	15.35551	-2.743277	0.0067
B1299	67.09774	16.71516	4.014184	0.0001
B0305	70.42349	16.00527	4.400019	0.0000
B0907	-90.70516	15.91594	-5.699015	0.0000
B0308	-37.88133	15.97923	-2.370660	0.0188

R-squared	0.975743	Mean dependent var	576.1671
Adjusted R-squared	0.973838	S.D. dependent var	93.88844
S.E. of regression	15.18625	Akaike info criterion	8.352802
Sum squared resid	44048.86	Schwarz criterion	8.610404
Log likelihood	-848.5150	F-statistic	512.1936
Durbin-Watson stat	1.997437	Prob(F-statistic)	0.000000

The symbol (-1) indicates that the variable is lagged 1 period.

Commercial Electricity Use Model

Dependent Variable: COMUSE+COMPROG
Method: Least Squares
Sample: 1993M03 2008M04
Included observations: 182

Variable	***Coefficient***	***Std. Error***	***t-Statistic***	***Prob.***
INTERCEPT	-8.636495	0.755620	-11.42968	0.0000
CDDY*COMSIZE*SUMSEAS	7.68E-07	2.82E-08	27.29299	0.0000
COMEMPLOY	6.140425	0.391298	15.69244	0.0000
COMRATE(-1)*NOCRISIS	-0.033451	0.010813	-3.093583	0.0023
COMRATE(-1)*CRISIS	-0.053651	0.010817	-4.959709	0.0000
BDAYS	0.009270	0.000478	19.41068	0.0000
JAN	-0.360629	0.061516	-5.862367	0.0000
MAR	-0.146531	0.051965	-2.819817	0.0054
OCT	0.312865	0.052229	5.990241	0.0000
DEC	-0.227388	0.054831	-4.147040	0.0001
B0798	-1.225722	0.180922	-6.774855	0.0000
B1298	0.893155	0.185701	4.809635	0.0000
B0801	0.974658	0.200210	4.868175	0.0000
B0898	0.714346	0.184025	3.881785	0.0001
B0998	-0.538029	0.183326	-2.934828	0.0038
B0907	-0.919054	0.186327	-4.932467	0.0000
B0706	-0.790512	0.187211	-4.222563	0.0000

R-squared	0.939265	Mean dependent var	7.097577
Adjusted R-squared	0.933375	S.D. dependent var	0.691919
S.E. of regression	0.178596	Akaike info criterion	-0.518626
Sum squared resid	5.262945	Schwarz criterion	-0.219350
Log likelihood	64.19494	F-statistic	159.4820
Durbin-Watson stat	1.974749	Prob(F-statistic)	0.000000

The symbol (-1) indicates that the variable is lagged 1 period

Industrial Electricity Use Model

Dependent Variable: INDUSE+INDPROG
Method: Least Squares
Sample: 1994M01 2008M04
Included observations: 172

Variable	***Coefficient***	***Std. Error***	***t-Statistic***	***Prob.***
INTERCEPT	0.256803	0.357793	0.717741	0.4740
CDDX*SUMSEAS	0.001299	0.000164	7.926043	0.0000
INDRATE*CRISIS	-0.051461	0.008542	-6.024407	0.0000
INDRATE*NOCRISIS	-0.038407	0.010089	-3.807005	0.0002
MANEMPLOY	1.050425	0.147093	7.141235	0.0000
BDAYS	0.003243	0.000284	11.41147	0.0000
TR	-0.001755	0.000312	-5.618116	0.0000
JAN	-0.191875	0.032948	-5.823634	0.0000
AUG	0.175168	0.039677	4.414860	0.0000
OCT	0.168194	0.029609	5.680445	0.0000
B0896	-0.368109	0.107457	-3.425647	0.0008
B0598	-0.402913	0.103887	-3.878367	0.0002
B1299	0.443394	0.114046	3.887838	0.0001
B0799	-0.262229	0.103433	-2.535263	0.0122
B0899	0.268415	0.108246	2.479680	0.0142
B0901	0.545634	0.118376	4.609342	0.0000
B0801	0.305679	0.120975	2.526800	0.0125
B0807	-0.274604	0.108518	-2.530484	0.0124

R-squared	0.893470	Mean dependent var	3.549006
Adjusted R-squared	0.881710	S.D. dependent var	0.296006
S.E. of regression	0.101806	Akaike info criterion	-1.632733
Sum squared resid	1.596130	Schwarz criterion	-1.303344
Log likelihood	158.4151	F-statistic	75.97662
Durbin-Watson stat	2.187074	Prob(F-statistic)	0.000000

Other Public Authority Electricity Use Model

Dependent Variable: OPAUSE+OPAPROG
Method: Least Squares
Sample (adjusted): 1993M01 2008M04
Included observations: 184

Variable	***Coefficient***	***Std. Error***	***t-Statistic***	***Prob.***
INTERCEPT	0.848516	0.205316	4.132725	0.0001
CDDX*SUMSEAS	0.002847	0.000103	27.68469	0.0000
OPARATE(-1)	-0.022543	0.004675	-4.822131	0.0000
GOVEMPLOY	0.206361	0.052068	3.963333	0.0001
BDAYS	0.001616	0.000186	8.696324	0.0000
TR	-0.002167	0.000107	-20.21200	0.0000
JAN	-0.078386	0.023784	-3.295735	0.0012
JUN	0.160992	0.020613	7.810045	0.0000
OCT	0.242910	0.022879	10.61729	0.0000
NOV	0.168482	0.023536	7.158621	0.0000
B0597	0.871788	0.073005	11.94150	0.0000
B0797	-0.816672	0.073583	-11.09860	0.0000
B1098	0.402241	0.075246	5.345678	0.0000
B0899	0.529757	0.073043	7.252623	0.0000
B0996	0.340481	0.073961	4.603501	0.0000
B0706	-0.359928	0.075527	-4.765574	0.0000
B0199	0.346494	0.075086	4.614647	0.0000
B0798	-0.193368	0.073633	-2.626095	0.0095
B1198	-0.374561	0.076046	-4.925471	0.0000
B0896	-0.327328	0.074472	-4.395309	0.0000
B0901	0.256454	0.076687	3.344147	0.0010
B0803	-0.190668	0.074877	-2.546423	0.0118
B0907	-0.276281	0.075235	-3.672215	0.0003

R-squared	0.939608	Mean dependent var	2.264038
Adjusted R-squared	0.931356	S.D. dependent var	0.276336
S.E. of regression	0.072400	Akaike info criterion	-2.296742
Sum squared resid	0.843932	Schwarz criterion	-1.894875
Log likelihood	234.3002	F-statistic	113.8596
Durbin-Watson stat	1.754647	Prob(F-statistic)	0.000000

The symbol (-1) indicates that the variable is lagged 1 period

Agriculture Electricity Use Model

Dependent Variable: AGUSE+AGPROG
Method: Least Squares
Sample: 1992M06 2008M04
Included observations: 191

Variable	*Coefficient*	*Std. Error*	*t-Statistic*	*Prob.*
INTERCEPT	-1.627022	0.699238	-2.326851	0.0212
AGRATE(-1)	-0.072548	0.026834	-2.703627	0.0076
BDAYS	0.007234	0.000916	7.895265	0.0000
RUNOFF	-0.001933	0.000221	-8.753773	0.0000
TR	0.009897	0.000648	15.28317	0.0000
APR	1.382260	0.123576	11.18555	0.0000
MAY	2.464533	0.150634	16.36109	0.0000
JUN	3.289963	0.136183	24.15849	0.0000
JUL	3.677996	0.123288	29.83256	0.0000
AUG	3.893752	0.120103	32.42016	0.0000
SEP	2.975521	0.119033	24.99740	0.0000
OCT	1.961015	0.118311	16.57502	0.0000
NOV	0.678194	0.118628	5.716959	0.0000
B0699	-2.002894	0.423364	-4.730906	0.0000
B0398	1.409573	0.413202	3.411339	0.0008
B0498	-2.379489	0.423090	-5.624076	0.0000
B0598	-1.065986	0.423150	-2.519168	0.0127
B0799	-1.442767	0.422399	-3.415648	0.0008
B0302	1.274418	0.413705	3.080501	0.0024
B0698	-1.610742	0.423130	-3.806728	0.0002
B0807	1.034265	0.426805	2.423273	0.0164
B0208	-0.992854	0.300440	-3.304670	0.0012

R-squared	0.946807	Mean dependent var	4.633298
Adjusted R-squared	0.940197	S.D. dependent var	1.669122
S.E. of regression	0.408177	Akaike info criterion	1.153759
Sum squared resid	28.15680	Schwarz criterion	1.528366
Log likelihood	-88.18398	F-statistic	143.2437
Durbin-Watson stat	1.640027	Prob(F-statistic)	0.000000

The symbol (-1) indicates that the variable is lagged 1 period

Street Light Electricity Use Model

Dependent Variable: STLTUSE
Method: Least Squares
Sample: 2001M06 2008M04
Included observations: 83

Variable	***Coefficient***	***Std. Error***	***t-Statistic***	***Prob.***
INTERCEPT	0.135024	0.167324	0.806959	0.4224
BDAYS	0.001136	0.000147	7.702396	0.0000
RESPRSTLT	0.007369	0.000431	17.11052	0.0000
JAN	0.111157	0.020210	5.500200	0.0000
FEB	0.092927	0.021072	4.409982	0.0000
MAR	0.062392	0.017195	3.628594	0.0005
OCT	0.049641	0.016858	2.944656	0.0044
NOV	0.093389	0.020066	4.654012	0.0000
DEC	0.130727	0.019191	6.811991	0.0000
B0506	0.124277	0.039801	3.122429	0.0026
B1106	-0.198682	0.043090	-4.610884	0.0000
AR(1)	0.354616	0.116718	3.038243	0.0033

R-squared	0.929162	Mean dependent var	3.247711
Adjusted R-squared	0.918187	S.D. dependent var	0.144444
S.E. of regression	0.041315	Akaike info criterion	-3.402168
Sum squared resid	0.121194	Schwarz criterion	-3.052457
Log likelihood	153.1900	F-statistic	84.66253
Durbin-Watson stat	1.994473	Prob(F-statistic)	0.000000

The AR(1) indicates the equation is adjusted for first order serial correlation.

8) Electricity Use Model Variable Description

Residential Electricity Use Model

ResUse	Residential class monthly electricity consumption in kWh per customer. Source: SCE.
CDDY	Cooling degree-days, dynamic population share weighted. Source: SCE and National Weather Service.
HDDY	Heating degree-days, dynamic population share weighted. Source: SCE and National Weather Service.
ResRate(-1)	Residential constant $2000 dollar price of electricity in cents per kWh in previous month. Source: SCE and Global Insight.
ResProg	SCE residential class monthly energy conservation program and by-pass avoided consumption in kWh per customer. Source: SCE.
RYprPop	Constant $2000 dollar total income per capita. Source: SCE and Global Insight.
BDays	Average number of days in monthly billing statement multiplied by the number of billing cycles in month. Source: SCE
Mar	Binary variable set equal to 1 for the month of March and zero otherwise.
Apr	Binary variable set equal to 1 for the month of April and zero otherwise.
Nov	Binary variable set equal to 1 for the month of November and zero otherwise.
Crisis	Binary variable set equal to one for the period February 2001 to January 2002 and zero otherwise.
NoCrisis	Binary variable set equal to zero for the period February 2001 to January 2002 and one otherwise.
Wealth	Binary variable with a starting value of one between January 2004 and December 2004, a value of 2 between January and December 2005, a value of 3.5 between January and December 2006, a value of 3.25 from January 2008 to August 2008, and value 0f 3.25 thereafter.
Bmmyy	Binary variables equal to one in a particular month and year, and zero otherwise, that are designed to capture billing irregularities in sales data.
HsldSize	Average residential household size in square feet. Source: McGraw-Hill.
SumSeas	A Binary equal to 1 during the summer months April to October and zero otherwise.
WinSeas	A Binary equal to 1 during the winter months November to March and zero otherwise.

Commercial Electricity Use Model

ComUse	Commercial class monthly electricity consumption in MWh per commercial customer. Source: SCE.
CDDY	Cooling degree-days, dynamic population share weighted. Source: SCE and National Weather Service
ComRate(-1)	Commercial class constant $2000 dollar price of electricity in cents per kWh in previous month. Source: SCE and Global Insight
ComEmploy	Commercial service monthly employment per thousand commercial building square feet. Source: Global Insight and McGraw-Hill.
ComProg	SCE commercial class monthly electricity conservation program and by-pass avoided consumption in MWh per customer. Source: SCE.
ComSize	Average commercial building size in square feet. Source: McGraw-Hill and SCE.
BDays	Average number of days in monthly billing statement multiplied by the number of billing cycles in month. Source: SCE
Jan	Binary variable set equal to 1 for the month of January and zero otherwise.
Mar	Binary variable set equal to 1 for the month of March and zero otherwise
Oct	Binary variable set equal to 1 for the month of October and zero otherwise.
Dec	Binary variable set equal to 1 for the month of December and zero otherwise.
Bmmyy	Binary variables equal to one in a particular month and year, and zero otherwise, that are designed to capture billing irregularities in sales data.
SumSeas	A binary equal to 1 during the summer months April to October and zero otherwise.
Crisis	Binary variable set equal to one for the period February 2001 to January 2002 and zero otherwise.
NoCrisis	Binary variable set equal to zero for the period February 2001 to January 2002 and one otherwise.

Industrial Electricity Use Model

IndUse	Industrial class monthly electricity consumption in kWh per industrial building square feet. Source: SCE and McGraw-Hill.
CDDX	Cooling degree-days static population weighting. Source: SCE and National Weather Service.
IndRate	Industrial class constant $2000 dollar price of electricity in cents per kWh in current month. Source: SCE and Global Insight.
ManfEmploy	Manufacturing sector monthly employment per thousand industrial building square feet. Source: Global Insight and McGraw-Hill.
IndProg	SCE industrial class monthly electricity conservation program and by-pass avoided consumption in kWh per industrial building square feet. Source: SCE and McGraw-Hill.
BDays	Average number of days in monthly billing statement multiplied by the number of billing cycles in a month. Source: SCE
TR	Linear counter variable designed to capture secular trend in industrial class electricity consumption not otherwise captured in the model.
Jan	Binary variable set equal to 1 for the month of January and zero otherwise.
Aug	Binary variable set equal to 1 for the month of August and zero otherwise.
Oct	Binary variable set equal to 1 for the month of October and zero otherwise.
Bmmyy	Binary variables equal to one on a particular month and year, and zero otherwise, that are designed to capture billing irregularities in sales data.
SumSeas	A binary equal to 1 during the summer months April to October and zero otherwise.
Crisis	Binary variable set equal to one for the period February 2001 to January 2002 and zero otherwise.
NoCrisis	Binary variable set equal to zero for the period February 2001 to January 2002 and one otherwise.

Other Public Authority Electricity Use Model

OPAUse	Other Public Authority class monthly electricity consumption in kWh per government building square feet. Source: SCE and McGraw-Hill.
CDDX	Cooling degree-days, static population weighted. Source: SCE and National Weather Service
OPARate(-1)	Other Public Authority class constant $2000 dollar price of electricity in cents per kWh in previous month. Source: SCE and Global Insight
OPAEmploy	Government employment per thousand government building square feet. Source: Global Insight and McGraw-Hill.
OPAProg	SCE Other Public Authority class monthly electricity conservation program and by-pass avoided consumption in kWh per government building square feet. Source: SCE and McGraw-Hill.
BDays	Average number of days in monthly billing statement multiplied by the number of billing cycles in month. Source: SCE
TR	Linear counter variable designed to capture secular trend in public authority class electricity consumption not otherwise captured in the model.
Jan	Binary variable set equal to 1 for the month of January and zero otherwise.
Jun	Binary variable set equal to 1 for the month of June and zero otherwise.
Oct	Binary variable set equal to 1 for the month of October and zero otherwise.
Nov	Binary variable set equal to 1 for the month of November and zero otherwise.
Bmmyy	Binary variables equal to one on a particular month and year, and zero otherwise, that are designed to capture billing irregularities in sales data.
SumSeas	Binary equal to 1 during the summer months April to October and zero otherwise.

Agriculture Electricity Use Model

AgUse	Agriculture class monthly electricity consumption in MWh per agriculture customer. Source: SCE
AgProg	SCE agriculture monthly electricity conservation program and by-pass consumption in MWh per agriculture customer. Source: SCE
AgRate(-1)	Agriculture class constant $2000 dollar price of electricity in cents per kWh in previous month. Source: SCE and Global Insight.
BDays	Average number of days in monthly billing statement multiplied by the number of billing cycles in month. Source: SCE
RunOff	Full natural flow of San Joaquin River at Friant Dam in cubic feet of flow per second. Source: U.S Department of the Interior.
TR	Linear counter variable designed to capture secular trend in public authority class electricity consumption not otherwise captured in the model.
Apr	Binary variable set equal to 1 for the month of April and zero otherwise.
May	Binary variable set equal to 1 for the month of May and zero otherwise.
Jun	Binary variable set equal to 1 for the month of June and zero otherwise.
Jul	Binary variable set equal to 1 for the month of July and zero otherwise.
Aug	Binary variable set equal to 1 for the month of August and zero otherwise.
Sep	Binary variable set equal to 1 for the month of September and zero otherwise.
Oct	Binary variable set equal to 1 for the month of October and zero otherwise.
Nov	Binary variable set equal to 1 for the month of November and zero otherwise.
Bmmyy	Binary variables equal to one on a particular month and year, and zero otherwise, that are designed to capture billing irregularities in sales data.

Street Lighting Electricity Use Model

StLtUse	Street light class electricity monthly consumption in MWh per street light customer. Source: SCE
ResprStLt	Number of residential customers per street lighting customers. Source: SCE.
BDays	Average number of days in monthly billing statement multiplied by the number of billing cycles in month. Source: SCE
Jan	Binary variable set equal to 1 for the month of January and zero otherwise.
Feb	Binary variable set equal to 1 for the month of February and zero otherwise.
Mar	Binary variable set equal to 1 for the month of March and zero otherwise.
Oct	Binary variable set equal to 1 for the month of October and zero otherwise.
Nov	Binary variable set equal to 1 for the month of November and zero otherwise.
Dec	Binary variable set equal to 1 for the month of December and zero otherwise.
Bmmyy	Binary variable equal to one on a particular month and year, and zero otherwise, that are designed to capture billing irregularities in sales data.

9) Model Statistics – Customer Models

The statistical details of the residential and non-residential customer models are shown below, while a glossary of terms follows in Section 10. Note that in the case of the industrial and Other Public Authority customer classes, the sales forecasts are constructed as the product of electricity consumption per square foot and total building square feet. An independent forecast of building square feet by building type was provided by McGraw-Hill.

Residential Customers

New residential customers account for the vast majority of all new customers. The forecast of residential customer additions is forecast in multiple steps: forecasting residential building permits, lagging the building permits for construction time to calculate new residential units, and then converting residential units to active residential customers using an assumption about future residential vacancy rates.

Residential building permits – Monthly number of new dwelling units approved for construction

Completed Units – Monthly number of new residential units completed and ready for occupancy

Total Residential Units – The number of residential dwelling units including occupied and vacant units. Existing units plus newly completed units provides a monthly count of total residential units. An annual estimate of total units, obtained from the E5 – City and County Population and Housing Estimate published by the California Department of Finance (DOF) is used as a check on the estimated housing stock.

Occupied Units – The number of dwelling units inhabited by a household and is the same as the monthly number of active residential customers by definition. The number of active customers is provided by the SCE billing system.

Vacancy Rate – The rate of unoccupied units and is percentage difference between total units and active residential meters.

Forecasting residential customer growth is a multi-step process. The initial step requires the forecasting of residential construction in the SCE service area. Historical monthly building permit data is collected from cities and places within the SCE service area. Residential building permits for California are obtained from DOF and the U. S. Census Bureau (Census Bureau). Global Insight (GI) provides the annual forecast of California building permits.

Using historical SCE and California data, the GI building permit forecast is shared downed to develop a projection of annual building permits for the SCE service territory. The share is usually based on the most recent five years of data. (The forecast of residential building permits is also compared to similar GI forecast of residential households). The annual number of residential building permits is distributed to the each month based on the historical monthly share.

The conversion of residential building permits to completed units /residential meter sets consists of distributing building permits across the succeeding following months using a set of monthly lag factors. The distributing of monthly building permits to the succeeding months is an estimation of the construction period. The monthly distribution factors are estimated in a regression equation providing the following values:

Monthly Distribution Building Permits to Completions

Month	Distribution Factor
Constant	914
Lag 1	.03428
Lag 2	.03178
Lag 3	.03988
Lag 4	.04678
Lag 5	.05235
Lag 6	.05671
Lag 7	.05983
Lag 8	.06170
Lag 9	.06232
Lag 10	.06170
Lag 11	.05983
Lag 12	.05671
Lag 13	.05235
Lag 14	.04674
Lag 15	.03988
Lag 16	.03178
Lag 17	.02244
Lag 18	.01184

Completed Units represents the monthly completion of the building permits and additions to the stock of housing units. The completed units are added to the existing stock to determine the change in the total number of units. A count of total residential units and vacancy rates are available from the annual E-5 City and County Population and Housing Estimates published by DOF. This annual count is used as a check on recorded growth in the housing stock. In most years the addition of completed units/meter sets results in a number greater then the total units reported by the DOF. That difference represents the number of demolished units.

A vacancy rate is estimated by comparing the total residential units and the number of active residential customers. A forecast of vacancy rate is applied to the residential housing stock. The resulting value is the number of the active residential customers. The change in the number of active residential customers represents the additions or deductions in residential customers. The following table provides the output of the forecasting process.

Residential Building Permits and Customer Forecast

RESIDENTAIL BUILDING PERMITS, UNITS AND CUSTOMERS

(1,000's of Units)

	Building	Total Units		Active Customers		Vaccancy
Year	Permits	Total	Ann'l Change	Total	Ann'l Change	Rate
1991	34.4	3,861.7	48.5	3,600.7	40.1	6.8
1992	32.9	3,893.6	32.0	3,626.0	25.3	6.9
1993	25.9	3,924.0	30.4	3,642.3	16.3	7.2
1994	32.9	3,950.2	26.2	3,664.5	22.2	7.2
1995	27.2	3,977.7	27.4	3,692.0	27.5	7.2
1996	29.7	4,004.5	26.8	3,726.7	34.7	6.9
1997	36.3	4,040.4	35.9	3,752.2	25.5	7.1
1998	39.4	4,064.5	24.1	3,791.2	39.0	6.7
1999	45.3	4,091.4	26.9	3,843.9	52.7	6.0
2000	43.8	4,120.6	29.2	3,885.0	41.1	5.7
2001	53.1	4,160.3	39.7	3,931.4	46.4	5.5
2002	60.4	4,208.5	48.2	3,977.2	45.8	5.5
2003	68.9	4,261.0	52.5	4,030.5	53.3	5.4
2004	73.1	4,321.9	60.9	4,086.5	56.0	5.4
2005	72.1	4,388.3	66.4	4,146.1	59.6	5.5
2006	63.3	4,452.2	63.8	4,205.5	59.4	5.5
2007	33.9	4,504.4	52.2	4,234.7	29.2	6.0
2008	24.4	4,536.2	31.8	4,260.4	25.7	6.1
2009	40.7	4,566.6	30.4	4,296.3	36.0	5.9

Commercial Customer Model

Dependent Variable: D(COMCUST)
Method: Least Squares
Sample: 1995M01 2008M04
Included observations: 160

Variable	Coefficient	Std. Error	t-Statistic	Prob.
INTERCEPT	-0.332788	87.97510	-0.003783	0.9970
D(COMCUST(-1))	0.584407	0.058400	10.00692	0.0000
B0598	1390.389	323.6266	4.296276	0.0000
B0298	-2332.938	320.8321	-7.271523	0.0000
B0398	5035.741	352.8701	14.27080	0.0000
B0498	-3440.235	381.6630	-9.013801	0.0000
B1199	1387.271	319.6627	4.339796	0.0000
B0301	837.0248	320.0687	2.615141	0.0098
PDL01	9.608279	2.637119	3.643475	0.0004

R-squared	0.757080	Mean dependent var	924.7063
Adjusted R-squared	0.744210	S.D. dependent var	629.6301
S.E. of regression	318.4399	Akaike info criterion	14.41935
Sum squared resid	15311996	Schwarz criterion	14.59233
Log likelihood	-1144.548	F-statistic	58.82540
Durbin-Watson stat	2.320502	Prob(F-statistic)	0.000000

Lag Distribution of D(RESACCT)

	i	Coefficient	Std. Error	t-Statistic
. * |	0	8.40724	2.30748	3.64348
. * |	1	14.4124	3.95568	3.64348
. * |	2	18.0155	4.94460	3.64348
. *|	3	19.2166	5.27424	3.64348
. * |	4	18.0155	4.94460	3.64348
. * |	5	14.4124	3.95568	3.64348
. * |	6	8.40724	2.30748	3.64348
Sum of Lags		100.887	27.6898	3.64348

The D(.) symbol indicates the first difference.
The PDL symbol indicates a polynomial distributed lag.
The symbol (-1) indicates that the variable is lagged 1 period

Industrial Customer Model

Dependent Variable: INDCUST
Method: Least Squares
Sample (adjusted): 1991M04 2008M04
Included observations: 205

Variable	Coefficient	Std. Error	t-Statistic	Prob.
INTERCEPT	1995.782	360.6977	5.533115	0.0000
TR	-3.407980	1.205062	-2.828053	0.0052
TR^2	-0.039936	0.007061	-5.655792	0.0000
INDCUST(-1)	0.860537	0.023803	36.15179	0.0000
B1995	114.4085	30.43636	3.758940	0.0002
B2001	-226.0978	36.44078	-6.204527	0.0000
B2003	192.4541	36.43153	5.282626	0.0000
B2007	209.3980	43.93120	4.766499	0.0000
B0293	-655.0392	121.9113	-5.373082	0.0000
B0199	378.2641	73.21387	5.166563	0.0000
PDL01	0.928083	0.214793	4.320831	0.0000

R-squared	0.999674	Mean dependent var	24419.85
Adjusted R-squared	0.999657	S.D. dependent var	6496.881
S.E. of regression	120.3298	Akaike info criterion	12.47051
Sum squared resid	2808976	Schwarz criterion	12.64882
Log likelihood	-1267.228	F-statistic	59450.01
Durbin-Watson stat	0.863961	Prob(F-statistic)	0.000000

Lag Distribution of MANEMPLOY

	i	Coefficient	Std. Error	t-Statistic
. * |	0	0.74247	0.17183	4.32083
. *|	1	1.11370	0.25775	4.32083
. *|	2	1.11370	0.25775	4.32083
. * |	3	0.74247	0.17183	4.32083
Sum of Lags		3.71233	0.85917	4.32083

The ^ indicates the square of the variable.
The PDL symbol indicates a polynomial distributed lag.
The symbol (-1) indicates that the variable is lagged 1 period

Other Public Authority Customer Model

Dependent Variable: OPACUST
Method: Least Squares
Sample: 2001M01 2008M04
Included observations: 88

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	18649.84	5135.936	3.631244	0.0005
TR	-101.3091	30.50113	-3.321488	0.0014
OPACUST(-1)	0.809638	0.049214	16.45142	0.0000
B0601	-69.24987	14.42531	-4.800581	0.0000
B0701	57.76339	14.29870	4.039765	0.0001
B1207	-44.24289	14.12561	-3.132105	0.0024
B0205	-73.97867	13.89209	-5.325235	0.0000
B0104	-52.24447	14.14117	-3.694493	0.0004
B2002	-24.14098	6.669635	-3.619535	0.0005

R-squared	0.999804	Mean dependent var	34192.07
Adjusted R-squared	0.999782	S.D. dependent var	927.8306
S.E. of regression	13.71121	Akaike info criterion	8.180949
Sum squared resid	14663.79	Schwarz criterion	8.462465
Log likelihood	-349.9618	F-statistic	44256.55
Durbin-Watson stat	1.497558	Prob(F-statistic)	0.000000

Lag Distribution of OPAFLSTCK

	i	Coefficient	Std. Error	t-Statistic
. * |	0	0.00123	0.00056	2.18300
. *|	1	0.00184	0.00084	2.18300
. *|	2	0.00184	0.00084	2.18300
. * |	3	0.00123	0.00056	2.18300
Sum of Lags		0.00613	0.00281	2.18300

The PDL symbol indicates a polynomial distributed lag.
The symbol (-1) indicates that the variable is lagged 1 period

Agriculture Customer Model

Dependent Variable: AGCUST
Method: Least Squares
Sample: 1993M06 2008M04
Included observations: 179

Variable	Coefficient	Std. Error	t-Statistic	Prob.
INTERCEPT	814.9323	470.4381	1.732284	0.0850
AGCUST(-1)	0.964386	0.017643	54.66081	0.0000
AGEMPLOY	1.021375	0.274820	3.716524	0.0003
TR	-0.676943	0.410355	-1.649652	0.1008
B0599	493.1933	29.77282	16.56522	0.0000
B0699	-525.9361	31.29548	-16.80550	0.0000
AR(1)	0.548493	0.071620	7.658347	0.0000

R-squared	0.999300	Mean dependent var	23732.23
Adjusted R-squared	0.999275	S.D. dependent var	1105.072
S.E. of regression	29.75179	Akaike info criterion	9.661977
Sum squared resid	152249.1	Schwarz criterion	9.786623
Log likelihood	-857.7469	F-statistic	40899.65
Durbin-Watson stat	2.092592	Prob(F-statistic)	0.000000

The symbol (-1) indicates that the variable is lagged 1 period.
The AR(1) indicates the equation is adjusted for first order serial correlation.

Street Light Customer Model

Dependent Variable: STRCUST
Method: Least Squares
Sample: 2000M01 2007M02
Included observations: 86

Variable	Coefficient	Std. Error	t-Statistic	Prob.
INTERCEPT	-261.4340	285.3594	-0.916157	0.3620
STLTCUST(-1)	0.956817	0.017858	53.57880	0.0000
APR	18.09193	9.408951	1.922842	0.0577
AUG	-27.80061	9.911020	-2.805020	0.0062
B0101	-195.3968	27.37997	-7.136486	0.0000
B1006	-124.2965	27.27195	-4.557669	0.0000
B0202	-97.41266	27.03238	-3.603555	0.0005
B0602	-103.6865	26.97862	-3.843283	0.0002
TR	6.949852	1.800156	3.860694	0.0002
PDL01	0.019412	0.011118	1.745971	0.0842

R-squared	0.999449	Mean dependent var	12640.65
Adjusted R-squared	0.999394	S.D. dependent var	1084.822
S.E. of regression	26.71003	Akaike info criterion	9.502595
Sum squared resid	64208.32	Schwarz criterion	9.763112
Log likelihood	-465.1297	F-statistic	18135.16
Durbin-Watson stat	1.893555	Prob(F-statistic)	0.000000

Lag Distribution of RESCUST

	i	Coefficient	Std. Error	t-Statistic
. * |	0	0.01699	0.00973	1.74597
. * |	1	0.02912	0.01668	1.74597
. * |	2	0.03640	0.02085	1.74597
. *|	3	0.03882	0.02224	1.74597
. * |	4	0.03640	0.02085	1.74597
. * |	5	0.02912	0.01668	1.74597
. * |	6	0.01699	0.00973	1.74597
Sum of Lags		0.20383	0.11674	1.74597

The (-1) indicates the variable is lagged 1 period.
The PDL symbol indicates a polynomial distributed lag.

10) Customer Model Variable Description

Commercial Customer Model

ComCust	Number of commercial class customers. Source: SCE.
PDL	Polynomial distributed lag of residential customers. Source: SCE
Bmmyy	Binary variables equal to one on a particular month and year, and zero otherwise, that are designed to capture billing irregularities in sales data.

Industrial Customer Model

IndCust	Number of industrial class customers. Source: SCE.
TR	Linear counter variable designed to capture secular trend growth not otherwise captured in the model.
PDL	Polynomial distributed lag of manufacturing employment. Source: Global Insight.
B1995	Binary variable equal to 1 in 1995 to 1997 and zero otherwise.
B2001	Binary variable equal to 1 in 2001 to 2003 and zero otherwise.
B2003	Binary variable equal to 1 in 2003 to 2004 and zero otherwise.
B2007	Binary variable equal to 1 in September 2006 to December 2009 and zero otherwise.
B0293	Binary variable equal to 1 in February 1993 and zero otherwise.
B0199	Binary variable equal to 1 in December 1998 to April 1999 and zero otherwise.

Other Public Authorities Customer Model

OPACust	Number of other public authority class customers. Source: SCE.
TR	Linear counter variable designed to capture secular trend growth not otherwise captured in the model.
PDL	Polynomial distributed lag of government building floor stock. Source: McGraw-Hill.
B2002	Binary variable equal to 1 in January 2001 to June 2003 and zero otherwise.
Bmmyy	Binary variables equal to one on a particular month and year, and zero otherwise, that are designed to capture billing irregularities in sales data.

Agriculture Customer Model

AgCust	Number of agriculture class customers. Source: SCE.
TR	Linear counter variable designed to capture secular trend growth not otherwise captured in the model.
AgEmploy	Number of persons employed in agriculture. Source: Global Insight.
Bmmyy	Binary variables equal to one on a particular month and year, and zero otherwise, that are designed to capture billing irregularities in sales data.

Street Light Customer Model

StLtCust	Number of street lighting customers. Source: SCE.
PDL	Polynomial distributed lag of number of residential customers. Source: SCE.
APR	Binary variable set equal to 1 for the month of April and zero otherwise.
AUG	Binary variable set equal to 1 for the month of August and zero otherwise.
TR	Time trend variable equal to 1 starting in June 2004 and increasing in increments to March 2006 an constant thereafter.
Bmmyy	Binary variables equal to one on a particular month and year, and zero otherwise, that are designed to capture billing irregularities in sales data.

11) Retail Energy and Retail Peak Demand at ISO Interface

Annual retail energy at the ISO settlement point is derived by adjusting the annual retail sales forecast for distribution losses. Specifically, we employ a historical average loss factor to retail sales in the following way:

Annual Retail Energy @ ISO = Annual Retail Sales * (1+ DLF)

where DLF is the ratio of ISO settlement quality meter data and retail sales at the customer meter, averaged over the years 2000 to 2006.

Monthly retail energy at ISO is derived through a series of steps that begins with the annual retail energy forecast. Annual retail energy is first distributed to each hour in the year using a set of hourly load shape equations. The load shapes are derived from econometric equations that relate each hour's recorded load to daily average temperature, calendar variables, such as day of week, month and holidays. Monthly energy is then derived simply by summing the hourly load associated with each calendar month. Monthly retail peak demand is determined by selecting the maximum hourly load in each calendar month.

Annual retail peak demand is estimated and forecast using a different procedure than that described above for monthly retail energy and monthly retail peak demand.

The procedure begins with the modeling and forecast of annual system peak. System peak includes the loads of retail customers, as well as load from various resale city customers. System peak demand is estimated and forecast as the sum of two components: base demand and weather-sensitive demand. The two components are derived from an econometric equation that relates summer season daily peak demand to daily maximum temperature and various calendar variables. The base demand is represented by the "intercept" term produced by this equation and weather sensitive demand is represented by the coefficient describing the relationship between changes in the temperature above 75 degrees and changes in that part of peak demand that is temperature sensitive during the weekdays in the month of August (an August weekday is assumed to be a likely time for the annual peak to occur).

The coefficients derived from the model described above are added to data sets consisting of base and weather sensitive coefficients estimated in past summer seasons. For system peak, these data sets comprise observations of base and weather sensitive coefficients from 1991 to 2007, with the 2007 summer season being the most recent estimate.These data sets become the dependent variables, or the variables to be explained, in another set of econometric models that estimate and forecast the change in base and weather sensitive peak demand components according to changes in the residential customer base. In other words, the observed growth in the two peak demand components is assumed to result primarily from growth in the residential customer base.

The retail annual peak is then derived by escalating the 2006 retail coefficients for base and weather sensitive demand according to forecast annual changes in the system base and weather sensitive components between 2007 and 2009

12) Incorporation of Energy Efficiency Impacts in Sales and Peak Demand Forecasting

Energy efficiency program savings are explicitly deducted in the modeling and forecasting of monthly billed retail sales. This forecast, in turn, through a series of steps, is converted into a forecast of bundled hourly load, which is necessarily also net of energy efficiency program savings.

Energy efficiency program savings (EE), measured in MWh, are explicitly included in SCE's models of electricity demand, both for model estimation and forecasting purposes. That is, electricity consumption and estimated EE enter on the "left-hand side" of our econometric equations. In this manner, we are able to construct demand equations that estimate and forecast the sum of net electricity consumption and a predetermined level of future EE.

More explicitly, we specify SCE program savings as a dependent variable in our econometric equations of electricity consumption per customer as follows:

(ResUse + ResEE) = f (CDD, HDD, Pr, Y, W, BDays)

(ComUse + ComEE) = f (CDD, Pr, Employ, BDays)

.

.

.

etc.

where ResUse is observed residential electricity consumption per customer, ResEE is estimated residential program efficiency savings per residential customer, CDD and HDD are weather variables, Pr is the average monthly electricity price, Y is real income and BDays refers to the number of days billed in the month.

The same general estimation specification is done for each of six customer classes. For example, ComUse and ComEE refer respectively to observed commercial class electricity consumption per customer and estimated commercial program efficiency savings per customer.

The reasoning behind this specification is that in the absence of SCE programs, changes in "avoided" electricity consumption will respond to changes in economic conditions, weather, and other variables in the same way as observed consumption. Since EE is predetermined in the forecast period, predicted net residential electricity consumption per customer is (ResUse + ResEE) – ResEE.

Historical DSM program impacts are provided to the Forecast Group in Energy Supply and Management by the Demand Planning Integration Group. Projected DSM program impacts are based upon CPUC approved targets.*

* CPUC Energy Savings Goals 2006 and Beyond, Decision 04-09-060, September 2004.

A forecast of total monthly billed sales (electricity consumption measured at the customer meter) is constructed as the product of forecast electricity consumption per customer and a forecast of total customers and then summing over all customer classes:

$ResUse_{t,m} \cdot ResCust_{t,m} = ResSales_{t,m}$

$ComUse_{t,m} \cdot ComCust_{t,m} = ComSales_{t,m}$

.

.

.
etc.

for each of the six customer classes, where t is a time index with t = 1, … 12, and m indicates that the data is monthly. ResCust and ComCust are the forecasts of residential and commercial class customers, respectively.

Annual sales in 2009, and other years, are then:

RetailSalesA = ∑m (t =1…12) (ResSalest,m + ComSalest,m + …..)

where A denotes annual data.

Bundled sales are derived as:

BundSalesA = RetailSalesA - DASalesA

where BundSalesA is annual electricity consumption by bundled customers and DASalesA is annual electricity consumption by Direct Access (DA) customers. DA sales are assumed to be a constant quantity over the forecast period (and thus a declining percentage of retail sales).

Annual bundled sales at the customer meter is converted to energy measured at ISO by applying an annual average distribution loss factor (DLF):

BundEnergyISO,A = BundSalesA · DLF

Annual bundled energy is then transformed to hourly bundled energy by use of an 8760 load shape allocation model (LS). The allocation is determined by the historical measured relationship between load and temperature throughout the year.

BundEnergyISO,h = f(LS (Temp))

where h is the hour (h=1, 2, … 8760) and Temp represents average daily temperature.

Monthly bundled peak demand is defined as the maximum hourly load in a calendar month:

PeakDemandISO, t=Jan → MAX (BundEnergyISO,h) (h=1 …744)

PeakDemandISO, t=Feb → MAX (BundEnergyISO,h) (h=745 …1416)
.
.
PeakDemandISO, t=Dec → MAX (BundEnergyISO,h) (h=8016 …8760)

Note that throughout this process, from the forecast of monthly billed sales at the customer meter to the forecast of monthly bundled peak demand at ISO, all energy is net of energy efficiency program savings. Thus EE impacts are preserved in SCE’s forecast of bundled peak demand in 2009 and all other years.

The only exception to the process described above is the forecast of annual peak demand – the highest hourly load in the year. SCE employs a separate forecasting methodology in order to forecast annual peak demand.

The annual peak forecast model relates observed annual peak demand to customers in the SCE service area:

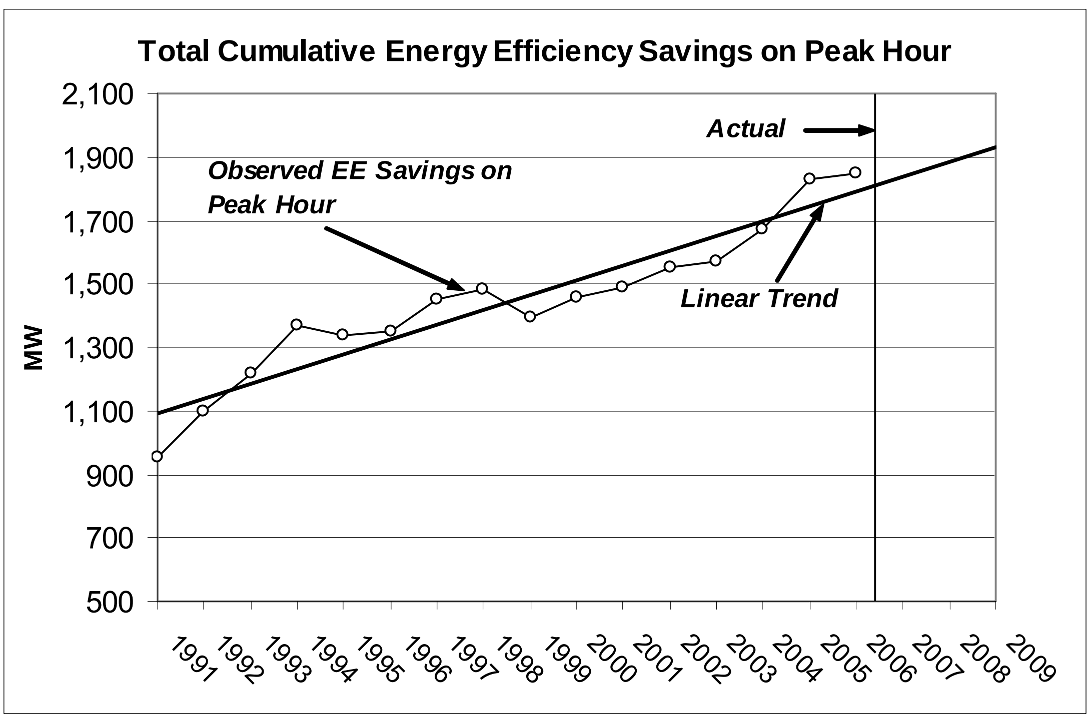
PeakDemandA,T = f(ResCustA,T + ComCustA,T) where A denotes annual peak demand, T is the year, for example 2009, and ResCust and ComCust are year-end residential and commercial class customers.

The annual peak forecast methodology does not explicitly include EE occurring on the peak hour, but instead implicitly captures the observed impact of energy savings on peak demand over the historical sample period. Thus, so long as future EE on the peak hour increase at the observed average annual rate of growth, future EE impacts on the annual peak are automatically captured in the forecast. An examination of EE savings on the peak hour between 1991 and 2006 (which represented the EE sample period available to SCE at the time of the Fall 2007 Forecast) suggests that a linear growth trend provides a reasonable forecast of future peak hour EE. Therefore, SCE's annual peak forecast is implicitly capturing a reasonable estimate of EE in the 2007 to 2009 period (about 1,925 MW in 2009 - see the diagram below).

If future analysis suggests that such implicit deductions are either too high or too low, SCE is prepared to make incremental adjustments for EE to its Peak Demand forecast in succeeding forecast implementations.

13) Forecast Calibration Procedures

Calibration is typically a procedure relevant to end use models. As discussed above, SCE uses econometric models for its estimation and forecasting. With econometric models, calibration, in a sense, occurs automatically in that the models attempt to calculate the best fit to historical data. Because SCE has a relatively large sample of historical data, such as recorded sales, weather, number of billing days, etc., we are confident that our models accurately explain variation in recorded sales over time. As shown above, the amount of variation explained by our econometric models is typically between 95 to 98 percent.



14) Hourly Loads by Sub Area

The forecasts presented here do not include hourly load by geographical area.

15) Economic and Demographic Projections

Residential Electricty Use - Economic and Demographic Drivers
Average Annual Rates of Change

	Customers	Electric Rate	Conservation	ByPass	Real Income per Capita	Household Size
1991-2007	1.0%	-0.6%	10.1%	17.7%	1.3%	0.6%
2007-2012	0.5%	1.6%	8.1%	23.8%	1.5%	0.6%
2012-2020	1.4%	0.0%	4.7%	9.5%	1.6%	0.6%

Commercial Electricty Use - Economic and Demographic Drivers
Average Annual Rates of Change

	Customers	Electric Rate	Conserv	ByPass	ComEmploy	Comsize	Floor Stock
1991-2007	2.3%	-0.6%	5.3%	7.6%	1.6%	-0.4%	1.8%
2007-2012	1.0%	1.6%	3.9%	12.0%	1.2%	0.5%	1.5%
2012-2020	2.4%	0.0%	3.6%	5.8%	1.3%	-0.9%	1.5%

Industrial Electricty Use - Economic and Demographic Drivers
Average Annual Rates of Change

	Customers	Electric Rate	Conserv	ByPass	IndEmploy	IndSize	IndFlStck
1991-2007	-5.5%	-0.8%	-1.6%	2.4%	-1.9%	5.8%	-0.1%
2007-2012	-5.0%	1.6%	-2.2%	1.8%	-0.9%	5.1%	-0.1%
2012-2020	-4.6%	0.0%	1.9%	1.5%	0.0%	4.7%	-0.1%

Electricity Demand Forecast Forms

California Energy Commission 2009 Integrated Energy Policy Report Docket Number 09-IEP-1C

Form 5

SCE Committed Demand-Side Program Forecast Methodology

SOUTHERN CALIFORNIA EDISON®

An *EDISON INTERNATIONAL*® Company

February 13th, 2009

Form 5 Committed Demand-Side Program Methodology
Renewable and Distributed Generation Program Costs and Impacts

Data Sources

SCE's forecast of self-generation is developed from the list of customers operating or planning to operate generating systems interconnected to the grid for the purpose of meeting their own energy requirements. This list of customers includes self-generation projects at various stages of development, including:

- systems on-line,
- systems under construction,
- systems currently being planned for installation

The description of each self-generation project includes customer description, nameplate capacity in kilowatts (kW), probable bypass kW, capacity factor, and on-line date. The list provides both estimated bypass capacity and estimated annual energy. SCE draws from multiple internal databases in an effort to make its list of customer self-generation projects as exhaustive as possible, including SCE's customer account data, customer generation project tracking system, and Rule 21 requests for interconnection. These databases contain data regarding DG (thermal generation) customers and NEM (solar/renewable) customers.

SCE develops separate forecasts for thermal and solar/renewable systems. The methodologies used to develop each of these forecasts are described further below. These forecasts are ultimately combined for use in SCE's forecast.

The customer generation costs reported by SCE for committed renewable and distributed generation reflect utility costs associated with delivering and administering the Self-Generation Incentive Program (SGIP) and California Solar Initiative (CSI) Program. Committed customer generation costs for SGIP are shown for 2001 – 2008. Costs of the SGIP were not tracked separately for thermal and solar-renewable projects. Consequently committed SGIP costs are reported as a single line-item that includes all incentivized technologies. Committed costs are shown for the CSI Program for 2007 - 2016. No costs are shown for thermal customer generation installed outside of the SGIP.

Forecasting Methodology

Thermal Generation

There are approximately 550 operational thermal systems ranging in size from 1KW to 76 Megawatts (MW) within the SCE service area. For thermal generation, annual energy impacts are calculated using the bypass capacity and a high capacity factor for all hours of the year.

For the period 2001 – 2007, customer incentives were available for selected thermal generation. For this period the historical data for committed thermal customer generation reflect impacts both from systems installed under the SGIP as well as systems installed by customers outside of the SGIP.

Beginning in 2008, the Self-Generation Incentive Program no longer provides incentives for thermal customer-generation systems.[1] Consequently the forecast of thermal self-generation reflects only projects self-financed by customers with no funding from utility incentive programs. Since thermal customer generation projects are not dependent on regulatory approval of program funding, they are treated as committed throughout the forecast horizon and included in SCE's demand forecast.

The forecast for 2008 includes generation facilities currently in the pipeline. The projection of thermal bypass for years 2009 and beyond is based on recent trends and current interconnection requests by customers. Based on these assumptions, 31 MW (240 GWh) are added in 2008 and approximately 25 MW (170 GWh) per year in years 2009 and beyond.

Costs for thermal customer generation are included in the reported SGIP costs for the period 2001 – 2007 when customer incentives for thermal generation technologies were available through the Self-Generation Incentive Program (SGIP). It is not possible to break out the SGIP reported costs of customer thermal generation separately during this period. No costs are shown for thermal customer generation installed outside of the SGIP.

Solar/Renewal Generation

There are approximately 4,300 operational solar/renewable systems ranging in size from 1KW to 630 KW within the SCE service area. For solar/renewable generation the annual energy for the historical period is calculated using the bypass capacity and an annual capacity factor for all hours of the year.[2]

Based on recent trends and current interconnection requests by customers, approximately 37 MW (68 GWh) per year of additional solar customer generation are forecasted in 2009 and 2010 through the CSI Program. Approximately 30 MW (55 GWh) of solar customer generation per year are added to the forecast for the period 2011 – 2016.

Decision D.06-01-024 allocated funding for CSI through 2016. Consequently SCE has reported the forecasted impacts of CSI as committed through the year 2016, and as uncommitted from 2017 – 2020.

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[1] Assembly Bill 27781 amended Public Utility Code § 379.62 relating to SGIP and limits program eligibility for SGIP incentives to qualifying wind and fuel cell distributed generation (DG) technologies, beginning January 1, 2008 through January 1, 2012. On November 21, 2008, The CPUC voted and approved advanced energy storage (AES) systems to receive SGIP incentives if coupled with an eligible DG technology under the SGIP.

[2] Capacity factors used by SCE are from the CPUC Self-Generation Incentive Program, Fifth Year Impact Evaluation, Draft-Final Report prepared by in February 2007 by Itron for PG&E and the Self-Generation Incentive Working Group.

Costs for renewable customer generation are included in the reported SGIP costs for the period 2001 – 2006 before solar technologies were transferred to the CSI program. It is not possible to break out the SGIP reported costs of customer solar-renewable generation separately during this period. Costs for the remainder of the forecast period reflect historical and forecasted costs of solar customer generation under the CSI Program. Based on recent trends, the impacts and costs of non-solar renewable customer generation are projected to be de minimis during the forecast horizon and are not reported separately.

Form 5 Committed Demand-Side Program Methodology
Energy Efficiency Program Costs and Impacts

SCE has classified Energy Efficiency program results 2000-2008 as committed. Program results 2009-2020 are considered uncommitted.

1. Describe how the peak and energy impacts are calculated

From 2000 through 2005, SCE utilized engineering workpapers, Evaluation, Measurement and Verification (EM&V) studies and/or California IOU standard values to estimate EE impacts and costs by measure.

In Decision 06-06-063 (June 29, 2006) the California Public Utilities Commission (CPUC) directed all California investor owned utilities to:

a) Use the Database for Energy Efficient Resources (DEER) values for peak kW and kilowatt hour (kWh) savings for those measures that are included in the DEER database.

b) Continue to use their best estimates of those values for measures that are not currently included in DEER, or for programs with measure categories rather than specific measures, such as customized rebate programs.

Since 2006 SCE has used the DEER peak demand reduction and annual energy savings estimates for measures found in the DEER. Detailed work papers documenting savings estimates are provided for those measures not found in the DEER. Note that SCE also documents in workpapers measure values that are derived through averaging DEER values.

2. Describe the basis or method used to estimate how first-year impacts might change over time

The 2000-2007 historic peak and energy impact data were extracted from SCE's Annual DSM reports, Annual Energy Efficiency reports and/or CPUC Energy Efficiency Quarterly Reports.

SCE's reported 2008 peak and energy impacts are primarily ex ante engineering estimates, whether the source is the DEER or SCE workpapers. While SCE has used the best available data at this time, the data are subject to change pending final reporting to the CPUC in March 2009.

3. Document the net-to-gross ratios used to convert gross measure or program impacts into net impacts

EE results reported for 2000-2008 are net impacts. Gross energy/demand impacts were converted to net impacts using the individual program net-to-gross ratios (NTGRs) contained in the CPUC Energy Efficiency Policy Manual.

(http://www.calmac.org/toolkitEE.asp)

Over the course of the 2006-2008 program cycle, some of the NTGRs were updated based on the results of the final 2004-2005 energy efficiency EM&V studies which can also be found on the CALMAC website.

4. Describe how the per-measure impact estimates are aggregated

SCE interpreted this question to be asking how measure level data were aggregated to the sector and program categories.

SCE deployed a bottom up methodology designed to aggregate EE impacts and costs to the sector and program level. SCE started by determining the energy/demand and costs measure level impacts (described in question 1 above). To calculate the sector and program measure level impacts, the per measure savings estimates (energy, demand and costs) were multiplied by the number of measure installations attributable to a mutually exclusive program and sector in a given year.

SIC/NAICS codes were used to allocate EE savings to the sector level where crosscutting EE programs and measures transcended multiple sectors. By using SIC/NAICS codes, SCE was able to allocate energy/demand savings and costs into mutually exclusive sector grouping (Residential, Commercial, and Industrial) and into mutually exclusive program categories (Retrofit and New Construction).

5. List any studies or sources relied on

Data for the years 2000 to 2005 were reported previously in SCE's 2007 IEPR Demand Forms. They are based on SCE's Demand-Side Management, Energy Efficiency and Low Income Energy Efficiency Annual Reports submitted between 2001 and 2006. The data were updated to reflect meter level energy/demand savings and cost data were normalized using 2007 dollars.

The 2006 data are based on SCE's Energy Efficiency and Low Income Energy Efficiency Annual Reports, filed in 2007.

The data for 2007 are based on SCE's 4th Quarter 2007 Energy Efficiency Report, submitted to the CPUC on March 7, 2008.

SCE has estimated energy/demand savings and costs for its 2008 Energy Efficiency and Low Income Energy Efficiency programs. These estimates are preliminary and subject to change pending final reporting to CPUC in March, 2009.

All Energy Efficiency Annual Reports can be found at:

http://www.sce.com/AboutSCE/Regulatory/eefilings/Annual_Reports/

All Low Income Annual Reports can be found at:

http://www.sce.com/AboutSCE/Regulatory/eefilings/lowincome.htm

6. **Discuss and document the different funding sources used and how funds are allocated to programs**

Edison’s EE programs are approved by the CPUC in three year increments, and LIEE programs prior to the upcoming 2009-2011 program cycle were approved by the CPUC in two year increments. These time increments are called program cycles.

Currently, SCE is authorized to recover costs associated with: (1) legislatively mandated EE or LIEE programs through a Public Goods Charge (PGC); and (2) Commission authorized procurement-related energy efficiency programs. SCE recovers its authorized PGC energy efficiency and procurement energy efficiency costs through its existing non-bypassable Public Purpose Programs Charge (PPPC), which applies to all of SCE’s retail customers.

On April 18, 2007, the CPUC approved SCE’s Advice Letter 1955-E retroactively approving SCE’s 2006-2008 EE program cycle effective February 5, 2006..

December 14, 2006, the CPUC approved SCE’s 2007-2008 LIEE program cycle in decision D. 06-12-038

Form 5 Committed Demand-Side Program Methodology Demand Response Program Costs and Impacts

SCE's committed Demand Response estimates reflect actual historical data based on the reports on Interruptible Load Programs and Demand Response Programs [1]. SCE is required, on a monthly basis, to submit MW load reductions for each interruptible load program and demand response program. The adjusted MW represents the load reduction that SCE reasonably expects to obtain during a demand response event based on the historical compliance or performance of each program.

Program Costs

- For 2000-2008, SCE used actual historical MW impacts and costs reported to the CPUC.
- Historical costs are adjusted to 2007 dollars, using GDP deflators[2] for 2000-2007.

<u>I6/BIP Program</u>

The I-6/BIP Program is a voluntary program that offers participants a monthly "capacity" bill credit in exchange for committing to reduce power to a minimum predetermined level on 15 or 30 minute notice during emergency situations. BIP imposes a significant penalty for non-performance. Customers who can reduce demand by 15% or a minimum of 100 kW, whichever is higher, have an IDR meter, and have telecommunications are eligible to participate. The program is designed for either DA or bundled customers who have a firm load reduction plan in place and can reduce load with certainty when requested. The penalty for non-performance is far greater than the incentive.

1. Describe how the estimates of peak impacts for each program are derived.

The adjusted MW reflects a composite program average performance for the two most recent events, occurring on August 25, 2005 and July 24, 2006. On August 25, 2005 the composite I-6 and BIP compliance rate was 98.5%, based on a comparison of the average kW demand exceeding the aggregate program Firm Service Level, to the Enrolled MW that month. On July 24, 2006 the composite I-6 and BIP compliance rate was 96.0%. The average rate for the two events was 97.3%. The Adjusted MW is equal to the compliance rate times the Enrolled MW.

2. Describe assumptions about eligible population, participation rates, price elasticities, wholesale market conditions, and prices used to develop the projections.

[1] Pursuant to Ordering Paragraph 17 of Decision No. 05-11-009, Decision No. 05-01-056, Ordering Paragraph 8 and Appendix F of Decision No. 02-04-060, and Ordering Paragraphs 24 and 25 of Decision No. 03-06-032 issued by the California Public Utilities Commission, SCE is required to submit Reports on Interruptible Load Program and Demand Response Programs.

[2] GDP Deflator, Global Insight CONTROL FORECAST

Committed program load impacts are based on historical data. No projections were developed.

3. For dispatchable programs, describe what criteria will be used in deciding whether to dispatch and how they will be operated to reduce the peak.

The I-6/BIP program is a reliability resource that can be triggered when a warning notice is issued by the CAISO and when Stage 1 is imminent. SCE can also call an event due to ISO emergencies, day-ahead load or price forecasts, supply resource limitations, a generating unit outage, transmission constraints, other system emergencies, or for other SCE procurement needs. Participants are notified of an event via Remote Terminal Unit (RTU) and dedicated, unlisted telephone line (as a courtesy, notifications may also be arranged via phone, pager, fax or email).

Option A: Reduce load within 15 minutes of an event notification.
Option B: Reduce load within 30 minutes of an event notification.

<u>Summer Discount Plan</u>

The SDP program is available for individually-metered residential and C&I customers with central air conditioning, where the air conditioner's electrical load is subject to temporary disconnection through automatic load control devices. There are two SDP options in which customers may enroll. The Base program is limited to 15 events during the summer months only, with a maximum duration of six hours, for a total of 90 hours of interruption. The incentive payment to a participant is based on the installed air conditioner tonnage and the customer's elected cycling strategy. The Enhanced SDP is identical in structure to the Base program, except that the number of events is unlimited resulting in potential interruptions of up to 720 hours during the summer.

1. Describe how the estimates of peak impacts for each program are derived.

Statistical analysis based on historical impact study, calibrated to actual tonnage and super hot day temperature (>100 deg) at selected SCE location, with correlated temperatures in other SCE weather zones.

2. Describe assumptions about eligible population, participation rates, price elasticities, wholesale market conditions, and prices used to develop the projections.

Activated by a remote radio signal, SCE will completely turn off a customer's air conditioner(s).

The amount of credit a customer receives depends on their current rate schedule, size of central AC unit, plan option (Base or Enhanced), turn-off option (continuously for the entire duration of the cycling event or 15 minutes out of every 30 minutes of the cycling event), amount of electricity used, and the number of SCE summer season days in the billing period. The amount of SDP credits will not exceed the amount of a customer's bill.

3. For dispatchable programs, describe what criteria will be used in deciding whether to dispatch and how they will be operated to reduce the peak.

The SDP program is a reliability resource that can be triggered during a CAISO Stage 2 emergency. SCE can also call an event due to ISO emergencies, day-ahead load or price forecasts, supply resource limitations, a generating unit outage, transmission constraints, other system emergencies, or for other SCE procurement needs. No event notification is sent. As a courtesy, notifications may be arranged via pager, email, or text messaging.

<u>Capacity Bidding Program</u>

The CBP Program pays customers for scheduled reductions in their demand. Customers offer to curtail an amount of their load a few days prior to a month in the summer when SCE calls on them to do so. SCE may ask those customers to reduce demand up to 24 hours during a month, when energy prices are highest.

1. Describe how the estimates of peak impacts for each program are derived.

Adjusted MW is based on monthly nominations. For November through April the highest sum of nominations from the summer is reported.

2. Describe assumptions about eligible population, participation rates, price elasticities, wholesale market conditions, and prices used to develop the projections.

Participants make monthly nominations and receive capacity payments based on the amount of capacity reduction nominated each month (whether or not an event is called), plus energy payments based on their actual kilowatt-hour (kWh) energy use reduction when an event is called. Payments vary based on month, product, and participation level.

3. For dispatchable programs, describe what criteria will be used in deciding whether to dispatch and how they will be operated to reduce the peak.

The CBP program is a price response resource that can be triggered when SCE forecasts a thermal unit heat rate of 15,000 Btu/kWh on a day-ahead or day-of basis. Participants are notified of an event via the CBP website (as a courtesy, notifications may also be arranged via phone, pager, or email).

Day-Ahead Event: By 3:00 p.m. the day before an event.
Day-of Event: Up to 30 minutes prior to the close of the CAISO hour-ahead market (approximately 3 hours before the start of a day-of event).

<u>Agricultural and Pumping Interruptible Program</u>

The AP-I Program offers qualifying customers a bill credit on energy usage for allowing SCE to temporarily shut off pumping equipment without advance notice.

1. Describe how the estimates of peak impacts for each program are derived.

Adjusted MW is based on actual monthly on-peak demand during the summer reporting months. Average of last summer's on-peak demands reported during winter months.

2. Describe assumptions about eligible population, participation rates, price elasticities, wholesale market conditions, and prices used to develop the projections.

Participants are required to reduce 100% of their load during an event.

Customers may cancel their contract during the designated one month window period, which runs between November 1 and December 1 of each year. Contract changes outside of this designated window are not allowed. Participants receive a year-round monthly bill credit of $0.00933 per kWh.

3. For dispatchable programs, describe what criteria will be used in deciding whether to dispatch and how they will be operated to reduce the peak.

The AP-I program is a reliability resource that can be triggered during a CAISO Stage 2 emergency. SCE can also call an event due to ISO emergencies, day-ahead load or price forecasts, supply resource limitations, a generating unit outage, transmission constraints, other system emergencies, or for other SCE procurement needs. No event notification is sent. As a courtesy, notifications may be arranged via pager, email, or text messaging.

Real Time Pricing Program

The RTP program is a dynamic TOU pricing tariff that charges participants for the electricity they consume based on hourly prices driven by temperature. Participants may choose to make adjustments in their electricity usage based on the hourly prices within different temperature ranges (i.e. Extremely Hot, Very Hot, Hot, Moderate, Mild Summer Temperatures, and High Cost/Low Cost Winter).

1. Describe how the estimates of peak impacts for each program are derived.

Adjusted MW is estimated based on 2007 data comparing load reductions on an extremely hot day to load reductions on a mild day.

2. Describe assumptions about eligible population, participation rates, price elasticities, wholesale market conditions, and prices used to develop the projections.

Hourly rates vary driven by temperature and time of day and energy charges become increasingly higher during peak time periods and when the temperature is high.

Demand Bidding Program

The DBP program is a no-risk internet-based bidding program whereby participants earn bill credits for voluntarily reducing their power usage when a DBP event is called. Good candidates for this program are those customers that can reduce power that is not critical to their main operations or processes on days when an event is activated. Hours of events are from noon to 8:00 pm, Monday through Friday, excluding holidays.

1. Describe how the estimates of peak impacts for each program are derived.

Adjusted MW is based on performance percentage (highest single hourly reduction during summer event divided by annual max demand of enrolled customers) applied to current enrolled customers.

2. Describe assumptions about eligible population, participation rates, price elasticities, wholesale market conditions, and prices used to develop the projections.

Credits offered for fulfilling 150%-200% of bid: $0.50 per kWh reduced for day-ahead events, and $0.60 per kWh reduced for day-of events.

3. For dispatchable programs, describe what criteria will be used in deciding whether to dispatch and how they will be operated to reduce the peak.

The DBP program is a price response resource that can be triggered when SCE forecasts a thermal unit heat rate of 15,000 Btu/kWh on a day-ahead or day-of basis. SCE can also call an event due to ISO emergencies, day-ahead load or price forecasts, supply resource limitations, a generating unit outage, transmission constraints, other system emergencies, or for other SCE procurement needs. Participants are notified of an event via the customer’s designated telephone line (as a courtesy, notifications may also be arranged via phone, pager, fax or email).

Day-Ahead Event: By 12:00 p.m. the day before an event.
Day-of Event: After Stage 1 emergency event is called, but no later than 6:00 p.m. on the day of an event.

Critical Peak Pricing

The CPP program customers receive a discount from the otherwise applicable rates they pay for energy on non-critical days, in return for paying a “critical peak” price for energy used in certain hours on a limited number of critical peak pricing “event” days. Customers enrolled in a CPP program are notified one day before a CPP event is called. Twelve event days are allowed per program year, which lasts from June through September.

SCE has two versions of CPP, CPP-VCD and CPP-GCCD. In the CPP – Volumetric Charge Discount (CPP-VCD) rate, the critical peak pricing period is split into two parts.

The “moderate” price period is from noon to 3 p.m., and the “high” price period is from 3 p.m. to 6 p.m. In the CPP – Generation Capacity Charge Discount (CPP-GCCD) rate, there is one critical peak pricing period lasting from noon to 6 p.m.

1. Describe how the estimates of peak impacts for each program are derived.

Adjusted MW is based on 15% of customer's annual max demand

2. Describe assumptions about eligible population, participation rates, price elasticities, wholesale market conditions, and prices used to develop the projections.

Energy rates are significantly higher during CPP events than during other summer hours. CPP-VCD participants receive reduced on-peak and mid-peak energy rates during non-CPP periods, while CPP-GCCD participants have no on-peak and mid-peak demand charges.

3. For dispatchable programs, describe what criteria will be used in deciding whether to dispatch and how they will be operated to reduce the peak.

The CPP program is a price response resource that may be triggered by forecasted high market prices, system constraints, or high temperatures. Participants are notified by 3:00 p.m. the day before an event via the customer’s designated telephone line (as a courtesy, notifications may also be arranged via phone, pager, fax or email).

Demand Response Contracts

The DRC program refers to contracts between SCE and third-party demand response contractors who develop their own demand response programs and provide load reductions to SCE. Customers enter into individual contractual arrangements with third-party DR contractors, and are compensated by the third-party DR contractor under the terms of their agreement.

1. Describe how the estimates of peak impacts for each program are derived.

Adjusted MW is based on monthly nominations of contract capacity.

2. Describe assumptions about eligible population, participation rates, price elasticities, wholesale market conditions, and prices used to develop the projections.

Customers enter into individual contractual arrangements with third-party DR contractors, and are compensated by the third-party DR contractor under the terms of their agreement. There are no forecasts on SCE’s part. The DR contractor performs the marketing and estimates the achievement.

3. For dispatchable programs, describe what criteria will be used in deciding whether to dispatch and how they will be operated to reduce the peak.

SCE can call a DRC event due to ISO emergencies, day-ahead load or price forecasts, supply resource limitations, a generating unit outage, transmission constraints, other system emergencies, or for other SCE procurement needs. When SCE calls a DRC event, third-party DR contractors are responsible for dropping electrical load on an aggregated portfolio basis based on their agreement with SCE.

Electricity Demand Forecast Forms

California Energy Commission 2009 Integrated Energy Policy Report Docket Number 09-IEP-1C

Form 6

SCE Uncommitted Demand-Side Program Forecast Methodology

SOUTHERN CALIFORNIA EDISON®

An EDISON INTERNATIONAL® Company

February 13th, 2009

Form 6 Uncommitted Demand-Side Program Methodology
Renewable and Distributed Generation Program Costs and Impacts

Data Sources

SCE's forecast of self-generation is developed from the list of customers operating or planning to operate generating systems interconnected to the grid for the purpose of meeting their own energy requirements. This list of customers includes self-generation projects at various stages of development, including:

- systems on-line,
- systems under construction,
- systems currently being planned for installation

The description of each self-generation project includes customer description, nameplate capacity in kilowatts (kW), probable bypass kW, capacity factor, and on-line date. The list provides both estimated bypass capacity and estimated annual energy. SCE draws from multiple internal databases in an effort to make its list of customer self-generation projects as exhaustive as possible, including SCE's customer account data, customer generation project tracking system, and Rule 21 requests for interconnection. These databases contain data regarding DG (thermal generation) customers and NEM (solar/renewable) customers.

SCE develops separate forecasts for thermal and solar/renewable systems. The methodologies used to develop each of these forecasts are described further below. These forecasts are ultimately combined for use in SCE's sales forecast.

Forecasting Methodology

Thermal Generation

As described in Form 5, SCE forecast of thermal customer generation is assumed to be committed throughout the forecast period. This decision reflects the fact that incentives are no longer available for thermal customer-generation systems. Consequently the forecast of thermal self-generation reflects only projects self-financed by customers with no funding from utility incentive programs. Since thermal customer generation projects are not dependent on regulatory approval of program funding, they are treated as committed throughout the forecast horizon and included in SCE's demand forecast.

Solar/Renewal Generation

Decision D.06-01-024 allocated funding for CSI through 2016. Given that the future of the program is uncertain after 2016, SCE has reported the forecasted impacts of solar/renewable generation as uncommitted from 2017 – 2020.

Based on recent trends and current interconnection requests by customers, approximately 30 MW (55 GWh) of solar customer generation per year are added to the forecast for the period 2017 – 2020. This forecast maintains the trend of the committed solar/renewable forecast, but re-characterizes the impacts from committed to uncommitted based on the uncertain future of the CSI Program after 2016.

SCE estimated program costs for solar-renewable generation for the period 2017 – 2020 based on the cost/kW of the CSI Program for the year 2016, the last year of authorized funding for the program. This cost/kW was assumed to be constant for the 2017 – 2020 uncommitted forecast period.

Form 6 Uncommitted Demand-Side Program Methodology
Energy Efficiency Program Costs and Impacts

For this filing, SCE has classified Energy Efficiency program results 2000-2008 as committed. Program results 2009-2020 are considered uncommitted.

1. **Describe how the peak and energy impacts are calculated**

   In decision D. 06-06-063 (June 29, 2006) the California Public Utilities Commission (CPUC) directed all California investor owned utilities to:

   a) Use the Database for Energy Efficient Resources (DEER) values for peak kW and kilowatt hour (kWh) savings for those measures that are included in the DEER database.

   b) Continue to use their best estimates of those values for measures that are not currently included in DEER, or for programs with measure categories rather than specific measures, such as customized rebate programs.

   Since 2006 SCE has used the DEER peak demand reduction and annual energy savings estimates for measures found in the DEER, and provides detailed work papers documenting savings estimates for those measures not found in the DEER. Note that SCE also documents in workpapers measure values that are derived through averaging DEER values. SCE's 2009-2011 uncommitted EE forecast reflects these data sources.

   For 2012-2020 SCE has reported total Market Gross (TMG) energy efficiency goals approved in D. 08-07-047

2. **Describe the basis or method used to estimate how first-year impacts might change over time**

   The 2009-2011 gross energy, demand and cost impacts were derived directly from SCE's 2009-2011 Energy Efficiency Program Funding Application (A.08-07-021) filed July 21, 2008 with the CPUC. SCE and other California IOUs have been directed to refile their applications. It is not known at this time what energy, demand or costs impacts will ultimately be approved by the CPUC.

   For 2012-2020, SCE has reported total Market Gross (TMG) energy efficiency goals approved in decision D. 08-07-047. Although the Commission approved TMG targets in decision D. 08-07-047, it is not known if the TMG targets will change over time as the Commission indicated that the targets will be updated in 2010.

3. **Document the net-to-gross ratios used to convert gross measure or program impacts into net impacts**

For the 2009-2011 program cycle, Decision (D.) 08-07-047 redefined the 2009-2011 energy and demand targets ordered in decision D. 04-09-060 as gross savings[1]. In order to assure congruence between CPUC decisions, the long-term EE strategic plan, and procurement planning, SCE's 2009-2011 energy and demand impacts are reported as "gross" inclusive of free riders.

For years 2012-2020, SCE's reported energy and demand impacts reflect the Total Market Gross (TMG) targets adopted in decision D. 08-07-047 (8/1/2008). This decision orders the IOUs to use 100% of the 2012-2020 TMG goals for long-term procurement planning[2]. SCE has complied with the CPUC's directive and reported TMG targets for 2012-2020.

4. Describe how the per-measure impact estimates are aggregated

SCE interpreted this question to be asking how measure level data were aggregated to the sector and program categories.

SCE deployed a bottom up methodology designed to aggregate EE impacts and costs to the sector and program level. SCE started by determining the energy/demand and costs measure level impacts (described in question 1 above). To calculate the sector and program measure level impacts, the per measure savings estimates (energy/demand and costs) were multiplied by the number of measure installations in the given year.

SIC/NAICS codes were used to allocate EE savings to the sector level where crosscutting EE programs and measures transcended multiple sectors. By using SIC/NAICS codes, SCE was able to allocate energy/demand savings and costs into mutually exclusive sector grouping (Residential, Commercial, and Industrial) and into mutually exclusive program categories (Retrofit and New Construction).

For years 2012 and beyond, SCE's Total Market Gross (TMG) targets (D. 08-07-047) were used. CPUC decision D. 08-07-047 did not breakout EE targets by sector, end use or measure. SCE's EE forecast is reported using the same categories used in the decision:

- SCE Total
- Huffman Bill (AB1109)
- Codes and Standards
- Big Bold Energy Efficiency Strategies (BBEES)

5. List any studies or sources used to support these assumptions

[1] D. 08-07-047, O.P. 4
[2] D. 08-07-047, O.P. 3

Data for the 2009-2011 EE program cycle were filed with the CPUC in SCE's 2009-2011 Energy Efficiency Program Funding Application (A.08-07-021), dated July 21, 2008.

Data for years 2009-2011 LIEE energy demand and cost impacts were approved by the CPUC in decision D. 08-11-031, dated November 6, 2008.

Data for years 2012-2020 energy and demand impacts are Total Market Gross (TMG) and were derived from D. 08-07-047 (8/1/2008) Table 2, page 22, and Appendix table A-4, page 2.

6. Discuss and document the different funding sources used and how funds are allocated to programs

Starting in 2009 both energy efficiency (EE) and low income (LIEE) programs are approved by the CPUC in three year increments called program cycles. The upcoming program cycle starts in 2009 and ends in 2011 (i.e., the 2009-2011 program cycle).

SCE’s 2009-2011 EE programs have not been approved to date, and SCE is operating under bridge funding approved in decision D. 08-10-027.

SCE’s LIEE 2009-2011 program cycle was approved by the CPUC in Decision (D.) 08-11-031.

Currently, SCE is authorized to recover both EE and LIEE program costs associated with: (1) legislatively mandated energy efficiency programs PGC; and (2) Commission authorized procurement-related energy efficiency programs. SCE recovers its authorized PGC energy efficiency and procurement energy efficiency costs through its existing non-bypassable Public Purpose Programs Charge (PPPC) which applies to all of SCE’s retail customers.

Costs shown for 2012-2020 reflect only the estimated costs associated with SCE programs. Costs associated with the Huffman Bill, Codes and Standards and BBEES would be borne directly by customers, and are not known at this time.

7. Discuss the current status of programs included in the uncommitted forecast

The 2009-2011 gross energy, demand and cost impacts were derived directly from SCE's 2009-2011 Energy Efficiency Program Funding Application (A. 08-07-021) filed July 21, 2008 with the CPUC. SCE and the other IOUs have been directed to refile their 2009-2011 applications. It is not known, at this time, what energy, demand and costs impacts will ultimately be approved by the CPUC.

Program cycles for 2012 and beyond have not been addressed by the CPUC.

8. Describe the process that will lead to change in status from uncommitted to committed, and whether this status change is under the control of the LSE or imposed though regulatory requirements

Once the Energy Efficiency 2009-2011 Program Funding Application (A. 08-07-021) or its successor is ultimately approved by the CPUC, the 2009-2011 EE programs status should be changed from uncommitted to the committed category.

Years 2012-2020 should remain categorized as uncommitted until such time as the CPUC approves program cycles beyond 2011.

Form 6 Uncommitted Demand-Side Program Methodology Demand Response Program Costs and Impacts

SCE's uncommitted Demand Response forecast reflects ex ante estimates based on the Load Impact Protocols[1], Amended Demand Response Application[2], and SmartConnect Business Case[3].

Program Load Impacts

Forecasted impacts and costs were developed for six of SCE's largest DR programs using the Load Impact Protocols:

- The Base Interruptible Program (BIP)
- The Summer Discount Plan (SDP) program
- The Agricultural and Pumping Interruptible (AP-I) program
- The Demand Bidding Program (DBP)
- The Capacity Bidding Program (CBP)
- The Real Time Pricing tariff (RTP)

Each of these programs was included in SCE's 2009-2011 DR Application (A.08-06-001). With the exception of RTP, each of these programs is considered dispatchable. Detailed documentation of the methodology and results associated with ex ante impact estimates is provided in two reports that are attachments in the Amended DR Application (A.08-06-001). One report, by Freeman, Sullivan & Co. (A.08-06-001, Appendix F), covers the first five programs while the second report, by Christensen Associates Energy Consulting (A.08-06-001, Appendices G & H), covers the DBP program. The FSC report also contains summaries of the total impact for all programs organized by notification lead time (e.g., day-ahead, day-of with 3 hour notification and day-of with 30 minutes notification) and by trigger methodology (e.g., 15,000 Btu heat rate trigger, emergency trigger, etc.). For each of the six DR programs listed above, models were developed to estimate ex ante load impacts.

Event Days and Weather Years

For event-based programs, the Load Impact Protocols require that the ex ante load impact estimates be based on ex post analysis of existing programs whenever the existing data and characteristics of the program allow for such an approach. The CEC directed SCE to use weather conditions representative of a 1-in-2 weather year, peak load day, at hour ending 15:00 for the aggregate of all customers participating in the program.

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[1] D.08-04-050, Attachment A, *Load Impact Estimation for Demand Response: Protocols and Regulatory Guidance*, California Public Utilities Commission, Energy Division, April 2008 (the Load Impact Protocols).
[2] A.08-06-001, Amended Testimony in Support of Southern California Edison Company's Amended Application for Approval of Demand Response Programs, Goals, and Budgets for 2009-2011
[3] D.08-09-039, Decision Approving Settlement on Southern California Edison Company Advanced Metering Infrastructure Deployment.

The 1-in-2 weather year was selected by SCE based on a proprietary methodology, using load-weighted weather data for selected weather stations and years. This load weighting methodology is used by SCE in other forecasting and resource planning applications, and was used here for consistency. The year 2002 was selected as the 1-in-2 weather year. For most DR resources, there is a higher probability that an event will be called on high system load days than on other days. As such, SCE chose the month of July because of the higher probability that a system peak load day will occur during this month.

Program Costs

- Forecasted program costs are adjusted to 2007 dollars using a GDP deflator[4] of 2.4%.
- Incentive costs for 2009-2020 were derived by dividing the total yearly incentives for each program in 2008 by the average of the adjusted MWs from January 2008 – December 2008. The resulting number (Cost per MW) was then multiplied by the forecasted MWs for each program, from 2009-2020.
- Program costs are assumed to remain constant starting 2012 until 2020 based on the average program costs for 2009-2011.

1. Discuss and document the different funding sources used and how funds are allocated to programs. Discuss the current status of the programs included in the uncommitted forecast.

As authorized in Decision 08-12-038, SCE is allowed to expend funds to continue certain 2008 demand response programs until the Commission adopts a final decision on the IOUs' demand response activity and budget applications for 2009-2011. In addition, this decision authorizes several pilot programs to test the use of demand response to provide participating load to the California Independent System Operator (CAISO). This decision will ensure that California continues to get the benefits of existing IOU demand response programs to reduce peak electricity load until final programs for 2009-2011 can be adopted, and will provide valuable information on the potential for demand response to provide participating load after implementation of the CAISO's Market Redesign and Technology Upgrade.

2. Describe the process that will lead to change in status from uncommitted to committed, and whether this change is under the control of the LSE or imposed through regulatory requirements.

The demand response programs will change from uncommitted to committed once the CPUC adopts a final decision on the IOUs' demand response activity and budget applications for 2009-2011 (A.08-06-001).

<u>I-6/BIP Program</u>

[4] GDP Deflator, Global Insight CONTROL FORECAST

The I-6/BIP Program is a voluntary program that offers participants a monthly "capacity" bill credit in exchange for committing to reduce power to a minimum predetermined level on 15 or 30 minute notice during emergency situations. BIP imposes a significant penalty for non-performance. Customers who can reduce demand by 15% or a minimum of 100 kW, whichever is higher, have an IDR meter, and have telecommunications are eligible to participate. The program is designed for either DA or bundled customers who have a firm load reduction plan in place and can reduce load with certainty when requested. The penalty for non-performance is far greater than the incentive.

1. Describe how the estimates of peak impacts for each program are derived.

Based on the I-6/BIP forecast model, the aggregate estimated impact in a 1-in-2 weather year, July peak load day, at hour ending 15:00 for 2009, 2010, and 2011, respectively, is 774, 855, and 944 MW. Rather than making gross assumptions on the outcome of various proceedings such as MRTU, DR application, DR OIR, and other unexpected policy changes, SCE is assuming the forecasted MW and program costs be held constant starting 2012 until 2020. The program will continue to provide a constant level of participation.

2. Describe assumptions about eligible population, participation rates, price elasticities, wholesale market conditions, and prices used to develop the projections.
.
Customers may cancel their contract during the designated one month window period, which runs between November 1 and December 1 of each year. Contract changes outside of this designated window are not allowed.

An I-6/BIP customer will be paid a monthly bill credit, regardless of whether or not there are interruption events. Bill credits vary according to voltage and are applied to the kW difference between each month's average peak demand and the customer's designated FSL.

3. For dispatchable programs, describe what criteria will be used in deciding whether to dispatch and how they will be operated to reduce the peak.

The I-6/BIP program is a reliability resource that can be triggered when a warning notice is issued by the CAISO and when Stage 1 is imminent. SCE can also call an event due to ISO emergencies, day-ahead load or price forecasts, supply resource limitations, a generating unit outage, transmission constraints, other system emergencies, or for other SCE procurement needs. Participants are notified of an event via Remote Terminal Unit (RTU) and dedicated, unlisted telephone line (as a courtesy, notifications may also be arranged via phone, pager, fax or email).

Option A: Reduce load within 15 minutes of an event notification.
Option B: Reduce load within 30 minutes of an event notification.

<u>Summer Discount Plan</u>

The SDP program is available for individually-metered residential and C&I customers with central air conditioning, where the air conditioner's electrical load is subject to temporary disconnection through automatic load control devices. There are two SDP options in which customers may enroll. The Base program is limited to 15 events during the summer months only, with a maximum duration of six hours, for a total of 90 hours of interruption. The incentive payment to a participant is based on the installed air conditioner tonnage and the customer's elected cycling strategy. The Enhanced SDP is identical in structure to the Base program, except that the number of events is unlimited resulting in potential interruptions of up to 720 hours during the summer.

1. Describe how the estimates of peak impacts for each program are derived.

Based on the SDP forecast model, the aggregate estimated impact in a 1-in-2 weather year, July peak load day, at hour ending 15:00 for 2009, 2010, and 2011, respectively, is 602, 606, and 611 MW. Rather than making gross assumptions on the outcome of various proceedings such as MRTU, DR application, DR OIR, and other unexpected policy changes, SCE is assuming the forecasted MW and program costs be held constant starting 2012 until 2020. The program will continue to provide a constant level of participation.

2. Describe assumptions about eligible population, participation rates, price elasticities, wholesale market conditions, and prices used to develop the projections.

Activated by a remote radio signal, SCE will completely turn off a customer's air conditioner(s).

The amount of credit a customer receives depends on their current rate schedule, size of central AC unit, plan option (Base or Enhanced), turn-off option (continuously for the entire duration of the cycling event or 15 minutes out of every 30 minutes of the cycling event), amount of electricity used, and the number of SCE summer season days in the billing period. The amount of SDP credits will not exceed the amount of a customer's bill.

3. For dispatchable programs, describe what criteria will be used in deciding whether to dispatch and how they will be operated to reduce the peak.

The SDP program is a reliability resource that can be triggered during a CAISO Stage 2 emergency. SCE can also call an event due to ISO emergencies, day-ahead load or price forecasts, supply resource limitations, a generating unit outage, transmission constraints, other system emergencies, or for other SCE procurement needs. No event notification is sent. As a courtesy, notifications may be arranged via pager, email, or text messaging.

<u>Capacity Bidding Program</u>

The CBP Program pays customers for scheduled reductions in their demand. Customers offer to curtail an amount of their load a few days prior to a month in the summer when

SCE calls on them to do so. SCE may ask those customers to reduce demand up to 24 hours during a month, when energy prices are highest.

1. Describe how the estimates of peak impacts for each program are derived.

Based on the CBP forecast model, the aggregate estimated impact in a 1-in-2 weather year, July peak load day, at hour ending 15:00 for 2009, 2010, and 2011, respectively, is 45, 47, and 49 MW. Rather than making gross assumptions on the outcome of various proceedings such as MRTU, DR application, DR OIR, and other unexpected policy changes, SCE is assuming CBP will grow at a simple 5% rate until 2014 and then be held constant until 2020. The program will continue to provide a constant level of participation.

2. Describe assumptions about eligible population, participation rates, price elasticities, wholesale market conditions, and prices used to develop the projections.

Participants make monthly nominations and receive capacity payments based on the amount of capacity reduction nominated each month (whether or not an event is called), plus energy payments based on their actual kilowatt-hour (kWh) energy use reduction when an event is called. Payments vary based on month, product, and participation level.

3. For dispatchable programs, describe what criteria will be used in deciding whether to dispatch and how they will be operated to reduce the peak.

The CBP program is a price response resource that can be triggered when SCE forecasts a thermal unit heat rate of 15,000 Btu/kWh on a day-ahead or day-of basis. Participants are notified of an event via the CBP website (as a courtesy, notifications may also be arranged via phone, pager, or email).

Day-Ahead Event: By 3:00 p.m. the day before an event.
Day-of Event: Up to 30 minutes prior to the close of the CAISO hour-ahead market (approximately 3 hours before the start of a day-of event).

<u>Agricultural and Pumping Interruptible Program</u>

The AP-I Program offers qualifying customers a bill credit on energy usage for allowing SCE to temporarily shut off pumping equipment without advance notice.

1. Describe how the estimates of peak impacts for each program are derived.

Based on the AP-I forecast model, the aggregate estimated impact in a 1-in-2 weather year, July peak load day, at hour ending 15:00 for 2009, 2010, and 2011, respectively, is 32, 32, and 33 MW. Rather than making gross assumptions on the outcome of various proceedings such as MRTU, DR application, DR OIR, and other unexpected policy changes, SCE is assuming the forecasted MW and program costs be held constant starting 2012 until 2020. The program will continue to provide a constant level of participation.

2. Describe assumptions about eligible population, participation rates, price elasticities, wholesale market conditions, and prices used to develop the projections.

Participants are required to reduce 100% of their load during an event.

Customers may cancel their contract during the designated one month window period, which runs between November 1 and December 1 of each year. Contract changes outside of this designated window are not allowed. Participants receive a year-round monthly bill credit of $0.00933 per kWh.

3. For dispatchable programs, describe what criteria will be used in deciding whether to dispatch and how they will be operated to reduce the peak.

The AP-I program is a reliability resource that can be triggered during a CAISO Stage 2 emergency. SCE can also call an event due to ISO emergencies, day-ahead load or price forecasts, supply resource limitations, a generating unit outage, transmission constraints, other system emergencies, or for other SCE procurement needs. No event notification is sent. As a courtesy, notifications may be arranged via pager, email, or text messaging.

Real Time Pricing Program

The RTP program is a dynamic TOU pricing tariff that charges participants for the electricity they consume based on hourly prices driven by temperature. Participants may choose to make adjustments in their electricity usage based on the hourly prices within different temperature ranges (i.e. Extremely Hot, Very Hot, Hot, Moderate, Mild Summer Temperatures, and High Cost/Low Cost Winter).

1. Describe how the estimates of peak impacts for each program are derived.

Based on the RTP forecast model, the aggregate estimated impact in a 1-in-2 weather year, July peak load day, at hour ending 15:00 for 2009, 2010, and 2011, respectively, is 4, 4, and 4 MW. Rather than making gross assumptions on the outcome of various proceedings such as MRTU, DR application, DR OIR, and other unexpected policy changes, SCE is assuming the forecasted MW and program costs be held constant starting 2012 until 2020. The program will continue to provide a constant level of participation.

2. Describe assumptions about eligible population, participation rates, price elasticities, wholesale market conditions, and prices used to develop the projections.

Hourly rates vary driven by temperature and time of day and energy charges become increasingly higher during peak time periods and when the temperature is high.

3. Describe the method used to develop estimates of nondispatchable program impacts and the extent to which the forecast is consistent with recent program performance.

The load impact for all customers is determined by the frequency of the various price schedules and, by connection, the weather in downtown Los Angeles for each prototypical weather year. The impact for any given day or hour is calculated as the difference between usage under RTP and usage under the otherwise applicable rate, generally TOU-8. For the ex-ante impact analysis, the RTP and TOU rates were assumed to remain roughly the same as current rates, after adjusting for inflation. More extreme weather years lead to a higher frequency of high hourly price profiles, which provide an incentive to shift or reduce load more frequently.

On average, the model predicts the load in each hour quite well. The only small consideration is that the model does not consistently capture the load shifting behavior as a result of the RTP rate. The amount that the model over predicts from 7 am to 7 pm is almost equal to the amount that the model under predicts in the other hours. Overall, the model does not over or under predict by more than 5 percent in any hour.

Demand Bidding Program

The DBP program is a no-risk internet-based bidding program whereby participants earn bill credits for voluntarily reducing their power usage when a DBP event is called. Good candidates for this program are those customers that can reduce power that is not critical to their main operations or processes on days when an event is activated. Hours of events are from noon to 8:00 pm, Monday through Friday, excluding holidays.

1. Describe how the estimates of peak impacts for each program are derived.

Based on the DBP forecast model, the aggregate estimated impact in a 1-in-2 weather year, July peak load day, at hour ending 15:00 for 2009, 2010, and 2011, respectively, is 17, 17, and 17 MW. Rather than making gross assumptions on the outcome of various proceedings such as MRTU, DR application, DR OIR, and other unexpected policy changes, SCE is assuming DBP will grow at a simple 5% rate until 2014 and then be held constant until 2020. The program will continue to provide a constant level of participation.

2. Describe assumptions about eligible population, participation rates, price elasticities, wholesale market conditions, and prices used to develop the projections.

Credits offered for fulfilling 150%-200% of bid: $0.50 per kWh reduced for day-ahead events, and $0.60 per kWh reduced for day-of events.

3. For dispatchable programs, describe what criteria will be used in deciding whether to dispatch and how they will be operated to reduce the peak.

The DBP program is a price response resource that can be triggered when SCE forecasts a thermal unit heat rate of 15,000 Btu/kWh on a day-ahead or day-of basis. SCE can also call an event due to ISO emergencies, day-ahead load or price forecasts, supply resource limitations, a generating unit outage, transmission constraints, other system emergencies, or for other SCE procurement needs. Participants are notified of an event via the customer's designated telephone line (as a courtesy, notifications may also be arranged via phone, pager, fax or email).

Day-Ahead Event: By 12:00 p.m. the day before an event.
Day-of Event: After Stage 1 emergency event is called, but no later than 6:00 p.m. on the day of an event.

Critical Peak Pricing

The CPP program customers receive a discount from the otherwise applicable rates they pay for energy on non-critical days, in return for paying a "critical peak" price for energy used in certain hours on a limited number of critical peak pricing "event" days. Customers enrolled in a CPP program are notified one day before a CPP event is called. Twelve event days are allowed per program year, which lasts from June through September.

SCE has two versions of CPP. In the CPP – Volumetric Charge Discount (CPP-VCD) rate, the critical peak pricing period is split into two parts. The "moderate" price period is from noon to 3 p.m., and the "high" price period is from 3 p.m. to 6 p.m. In the CPP – Generation Capacity Charge Discount (CPP-GCCD) rate, there is one critical peak pricing period lasting from noon to 6 p.m.

1. Describe how the estimates of peak impacts for each program are derived.

Based on the Amended DR Application, the aggregate estimated impact for 2009, 2010, and 2011, respectively, is 26, 58, and 59 MW. Rather than making gross assumptions on the outcome of various proceedings such as MRTU, DR application, DR OIR, and other unexpected policy changes, SCE is assuming the forecasted MW and program costs be held constant starting 2012 until 2020. The program will continue to provide a constant level of participation.

2. Describe assumptions about eligible population, participation rates, price elasticities, wholesale market conditions, and prices used to develop the projections.

SCE did not rely on enrollment estimates in order to forecast MW of load reduction. Rather, SCE estimated participation rates based on information from an analysis of participation rates and demand elasticities performed by the Lawrence Berkeley National Laboratory (LBNL).[5]

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[5] See *Estimating Demand Response Market Potential Amount Large Commercial and Industrial Customers: A Scoping Study*, January 2007, Charles Goldman, Nicole Hopper, Ranjit Bharvirkar, Bernie Neenan, and Peter Cappers.

Energy rates are significantly higher during CPP events than during other summer hours. CPP-VCD participants receive reduced on-peak and mid-peak energy rates during non-CPP periods, while CPP-GCCD participants have no on-peak and mid-peak demand charges.

3. For dispatchable programs, describe what criteria will be used in deciding whether to dispatch and how they will be operated to reduce the peak.

The CPP program is a price response resource that may be triggered by forecasted high market prices, system constraints, or high temperatures. Participants are notified by 3:00 p.m. the day before an event via the customer's designated telephone line (as a courtesy, notifications may also be arranged via phone, pager, fax or email).

Demand Response Contracts

The DRC program refers to contracts between SCE and third-party demand response contractors who develop their own demand response programs and provide load reductions to SCE. Customers enter into individual contractual arrangements with third-party DR contractors, and are compensated by the third-party DR contractor under the terms of their agreement.

1. Describe how the estimates of peak impacts for each program are derived.

Based on the Amended DR Application, the aggregate estimated impact for 2009, 2010, and 2011, 2012 respectively, is 206, 285, 380, and 355 MW. Rather than making gross assumptions on the outcome of various proceedings such as MRTU, DR application, DR OIR, and other unexpected policy changes, SCE is assuming the forecasted MW and program costs be held constant starting 2012 until 2020. The program will continue to provide a constant level of participation.

2. Describe assumptions about eligible population, participation rates, price elasticities, wholesale market conditions, and prices used to develop the projections.

Customers enter into individual contractual arrangements with third-party DR contractors, and are compensated by the third-party DR contractor under the terms of their agreement.

3. For dispatchable programs, describe what criteria will be used in deciding whether to dispatch and how they will be operated to reduce the peak.

SCE can call a DRC event due to ISO emergencies, day-ahead load or price forecasts, supply resource limitations, a generating unit outage, transmission constraints, other system emergencies, or for other SCE procurement needs. When SCE calls a DRC event, third-party DR contractors are responsible for dropping electrical load on an aggregated portfolio basis based on their agreement with SCE.

SCE has included 5 programs in its IEPR DR forecast that will be enabled by Edison SmartConnect:

- Peak Time Rebate (PTR)
- Time-of-Use (TOU)
- Programmable Communicating Thermostats (PCT)
- Critical Peak Pricing (CPP)

The forecasts for these programs are based on the estimates included in SCE's application for Edison SmartConnect and approved in D.08-09-039.

Peak Time Rebate (SmartConnect)

SCE's Peak Time Rebate (PTR) program is designed to provide price signals to residential customers to encourage load reductions during system peak conditions. The PTR credits will be applied to usage reductions during peak periods relative to a customer's baseline usage. SCE designed PTR for twelve events per year, although there is no maximum number of events that may be called in any year. Peak periods will be weekdays from 2 p.m. to 6 p.m., except holidays, and customers will be notified of PTR events the day prior to the event's occurrence.

1. Describe how the estimates of peak impacts for each program are derived.

SCE estimated the PTR peak impacts by modeling various input assumptions, including the participation rate, event awareness, price elasticities, and rebate amount.

2. Describe assumptions about eligible population, participation rates, price elasticities, wholesale market conditions, and prices used to develop the projections.

- Participation Rate and Enrollment. SCE assumed PTR enrollment, or PTR participation, to be 100%, as SCE will automatically enroll all residential customers.

Event Awareness. SCE assumed that 50% of residential customers would be knowledgeable of each upcoming PTR event.

- Price Elasticities. SCE used the price elasticity models derived from the Statewide Pricing Pilot. The Statewide Pricing Pilot (SPP) was a pricing research project designed to estimate the average impact of time-varying rates on energy use by rate period for residential and small commercial and industrial customers. An econometric analysis of the SPP dataset has yielded Pricing Impact Simulation Model (PRISM) which SCE used to estimate the PTR demand response impact. The SPP was authorized in D.03-03-036.

- Prices. During PTR events, SCE assumed that customers would earn a rebate of $0.66 / kWh for usage less than their baseline. The rebate amount is based on SCE's adjusted 2006 GRC long run avoided capacity cost of $75 / kW-year.

3. For dispatchable programs, describe what criteria will be used in deciding whether to dispatch and how they will be operated to reduce the peak.

PTR event days may be triggered by CAISO Electrical Emergency Alerts, SCE system emergencies, or SCE system and weather conditions. More specifically, when the predicted temperature for the next day in downtown Los Angeles reaches 90 degrees or hotter, SCE may call a PTR event day. SCE will utilize the forecasted weather and its system load forecast to determine whether a PTR event day is warranted. If system reserves appear adequate (*e.g.*, a low generation "heat-rate" (BTU / kWh)), then SCE may not call an event, even though the temperature trigger threshold has been met. This forecasted temperature trigger provides customers and the media with a simple, reliable method to anticipate PTR events.

4. Discuss and document the different funding sources used and how funds are allocated to programs.

As authorized in Decision 08-09-039, the PTR program will be funded through the Edison SmartConnect Program.

5. Discuss the current status of programs included in the uncommitted forecast.

No funding approved yet. SCE expects to implement the PTR program in Fall 2009. Customer eligibility will be subject to the SmartConnect meter availability and that the meter is ready for billing.

<u>Time-of-Use (SmartConnect)</u>

SCE's Time-of-Use (TOU) tariff is a non-event based rate that will provide customers an incentive to reduce usage during peak periods throughout the year. Eligible customers may opt into TOU from their current five tier rate schedule (i.e., otherwise applicable tariff). Peak periods will be from 2 p.m. to 6 p.m. weekdays, except holidays, and the summer season will be from June 1 to October 1 of each year.

1. Describe how the estimates of peak impacts for each program are derived.

SCE estimated the TOU peak impacts by modeling various input assumptions based on the California Statewide Pricing Pilot, including the participation rate, price elasticities, and TOU rates.

2. Describe assumptions about eligible population, participation rates, price elasticities, wholesale market conditions, and prices used to develop the projections.

- <u>Eligibility</u>. Residential customers will be eligible for TOU on an optional basis.

- <u>Participation Rate</u>. Based on an analysis of bill impacts, SCE estimated that 6% of customers would opt-in to the TOU rate.

- Price Elasticities. SCE used the price elasticity models derived from the Statewide Pricing Pilot.

- Prices. SCE estimated rates assuming an AB1X compliant tiered TOU rate.

3. Discuss and document the different funding sources used and how funds are allocated to programs.

As authorized in Decision 08-09-039, an AB1X compliant tiered TOU tariff will be funded through the Edison SmartConnect Program.

4. Discuss the current status of programs included in the uncommitted forecast.

SCE expects to implement the tiered TOU tariff in Fall 2009. Customer eligibility will be subject to meter availability.

Programmable Communicating Thermostats (SmartConnect)

SCE's Programmable Communicating Thermostat (PCT) program is designed to provide automated load reductions through the Edison SmartConnect meter and the customer's PCT device. The PCT program will provide two-way communication with the PCT devices to transfer temperature set point information, event status, and enable customer overrides during PCT events. The Edison SmartConnect™ meters, through the Home Area Network interface, will be the link between the PCTs and the SCE communication infrastructure. During an event, the PCT settings will be raised 4 degrees through the Edison SmartConnect™ meter. SCE may call up to 15 economic events and 5 reliability events per year, in exchange for an annual incentive credit on the customer's bill. In addition, customers will be allowed to override up to five events per year at a predetermined charge per event.

1. Describe how the estimates of peak impacts for each program are derived.

SCE estimated the PCT peak impacts by modeling various input assumptions based on the California Statewide Pricing Pilot, including the participation rate, diversified load reduction, and the number of air conditioning units per household. SCE's diversified load reduction includes the effects of customer overrides, and the net effect of air conditioner operational duty cycles during the demand response event, which includes inoperative units and units that are running at full load and providing maximum reductions.

2. Describe assumptions about eligible population, participation rates, price elasticities, wholesale market conditions, and prices used to develop the projections.

- Eligibility. Bundled service residential customers with central air conditioning will be eligible for the PCT program, except those customers that are enrolled in SCE's air-conditioning cycling program.

- Participation Rate. SCE expects that it can enroll about 25% of residential customers with central air conditioning and an Edison SmartConnect meter.

- Load Drop Estimate. SCE assumed a 1 kWh per hour (1kW) diversified load reduction per customer, which includes the effects of customer overrides, and the net effect of air conditioner operational duty cycles during the demand response event, which includes inoperative units and units that are running at full load and providing maximum reductions.

- Incentive. Enrolled customers will receive an annual incentive credit on their bill.

3. For dispatchable programs, describe what criteria will be used in deciding whether to dispatch and how they will be operated to reduce the peak.

Events will be called based on any one of the following criteria: (1) upon notification to SCE from the California Independent System Operator (ISO) of the need to implement load reductions in SCE's service territory, or (2) when a declaration by SCE of a Category One, Two, or Three Storm Alert exists that may jeopardize the integrity of SCE's distribution facilities.

4. Discuss and document the different funding sources used and how funds are allocated to programs.

SCE's PCT program will be funded through the DR Application.

5. Discuss the current status of programs included in the uncommitted forecast.

SCE will implement the PCT tariff in Fall 2009. Customer eligibility will be subject to the SmartConnect meter availability, the meter is ready for billing, and PCT device is properly installed, registered, and communicating.

Critical Peak Pricing (SmartConnect)

Critical Peak Pricing (CPP) is an event-based pricing program that will provide for significant charges for usage during peak periods of CPP event days. SCE designed CPP for twelve events per year, although the tariff will provide for a maximum of 15 events per year. Peak periods will be weekdays from 2 p.m. to 6 p.m., except holidays, and customers will be notified of CPP events the day prior to the event's occurrence.

1. Describe how the estimates of peak impacts for each program are derived.

SCE estimated the CPP peak impacts by modeling various input assumptions based on the California Statewide Pricing Pilot, including the participation rate, price elasticities, and CPP charge. Consistent with the SPP results, SCE has not calculated any demand response reductions from its small C&I customers (< 20 kW) because these customers did not provide statistically significant demand response.

2. Describe assumptions about eligible population, participation rates, price elasticities, wholesale market conditions, and prices used to develop the projections.

- Eligibility. Bundled service C&I customers with demands less than 200 kW may opt into CPP.

- Participation Rate. The CPP participation rate for C&I customers with demands between 20 kW and 200 kW was estimated to be 25%.

- Price Elasticities. SCE used the price elasticity models derived from the Statewide Pricing Pilot. The Statewide Pricing Pilot (SPP) was a pricing research project designed to estimate the average impact of time-varying rates on energy use by rate period for residential and small commercial and industrial customers. The SPP was authorized in D.03-03-036.

- Prices. SCE assumed that customers would be charged $0.66 / kWh in addition to their TOU or OAT rate.

3. For dispatchable programs, describe what criteria will be used in deciding whether to dispatch and how they will be operated to reduce the peak.

The event triggering criteria are the same as the Peak Time Rebate program.

4. Discuss and document the different funding sources used and how funds are allocated to programs.

As authorized in Decision 08-09-039, the CPP program for customers with demand less than 200 kW will be funded through the Edison SmartConnect Program.

5. Discuss the current status of programs included in the uncommitted forecast.

SCE expects to implement the CPP program in Fall 2009. Customer eligibility will be subject to the SmartConnect meter availability and that the meter is ready for billing.

Time-of-Use (Commercial and industrial < 200 kW)

SCE will continue to provide Time-Of-Use (TOU) rates for its small and medium commercial and industrial (C&I) customers. The TOU tariffs will provide customers an incentive to reduce usage during peak periods throughout the year. Medium C&I customers (20 kW to 200 kW) will be defaulted to the TOU rate, and will have the choice to opt out into their otherwise applicable tariffs (OAT), while small C&I customers (< 20 kW) will remain on their OAT and have the option of enrolling into a TOU rate.

1. Discuss how the estimates of peak impacts for each uncommitted program were derived.

SCE estimated the TOU peak impacts by modeling various input assumptions based on the California Statewide Pricing Pilot, including the participation rate, price elasticities, and TOU rates. Consistent with the SPP results, SCE has not calculated any demand response reductions from its small C&I customers (< 20 kW) because these customers did not provide statistically significant demand response.

2. Describe assumptions about eligible population, participation rates, price elasticities, wholesale market conditions, and prices used to develop the projections.

- Eligibility. C&I customers with demands between 20 kW and 200 kW will be defaulted to TOU. C&I customers with demands less than 20 KW will have the option of enrolling in a TOU tariff.

- Participation Rate. SCE estimated that 51% of customers with demand between 20 kW and 200 kW would participate in the TOU rate.

- Price Elasticities. SCE used the price elasticity models derived from the Statewide Pricing Pilot.

- Prices. SCE estimated the demand response using estimated TOU rates.

3. Discuss and document the different funding sources used and how funds are allocated to programs.

As authorized in Decision 08-09-039, the TOU tariffs for C&I customers with demand less than 200 kW will be funded through the Edison SmartConnect Program.

4. Discuss the current status of programs included in the uncommitted forecast.

Updated TOU tariffs are part of SCE's 2009 GRC Phase 2 application. SCE expects to implement the revised tariffs in Fall 2009. Customer eligibility will be subject to the meter availability.