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SCE 2015 IEPR Form 6 Incremental Demand-Side Program Methodology

Southern California Edison

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Form 6—Incremental Demand-Side Program Methodology for Southern California Edison

In December 2014, the Energy Commission issued Forms and instruction for Submitting Electricity Demand Forecasts prepared in support of the 2015 Integrated Energy Policy Report (IEPR)[1]. Southern California Edison (SCE) understands that Form 5 Committed Demand-Side Program methodology narrative is no longer required.

Below, please find the Incremental Demand-Side Program Methodology for Efficiency Programs, Demand Response Program Impacts, and Renewable and Distributed Generation Program Impacts.

Efficiency Program Impacts:

Document the estimated incremental load impacts reported in Form 3.2. List any studies or sources used to support these assumptions. Describe the method by which potential load impacts are reconciled with the UDC's demand forecast as reported in Form 1.

Consistent with Form 3 requirements, SCE has provided forecasted energy and coincident peak impacts expected to be achieved by SCE Energy Efficiency (EE) Programs. SCE's load forecast methodology has recently changed requiring data provided in form 3.2 to deviate from past IEPR cycles.

SCE's load forecast methodology now deploys the use of past EE program impacts to estimate future EE savings without using EE savings forecasts, and does not export an unmanaged forecast. As a result all future/forecasted EE savings are incremental to Demand-Side Management (DSM) considerations embedded in SCE's demand forecast.

The EE program savings impacts are provided by market sector data (Agriculture, Commercial, Industrial, and Residential). The following sources of EE savings were used:

1. 2013 reported EE program savings
2. 2014 preliminary EE program savings (final reported savings will not be available until June 2015)
3. 2015 EE program plans
4. 2016-2024 annual incremental EE savings[2]
5. 2025 and 2026 assume savings consistent with the last year of the 2013 EE Potential study

[1] CEC-200-2014-006-SF , December 2014

[2] 2013 California Energy Efficiency Potential and Goals Study Final Report, Navigant Consulting Inc., February 14, 2014 - http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M088/K661/88661468.PDF

EE program demand (in MW) impacts are consistent with the California Public Utilities Commission definition of demand savings promulgated in Decision 06-06-063[3], which defines peak impacts as the average grid level impact for a measure between the hours of 2:00 p.m. and 5:00 p.m. during the three consecutive hottest weekdays of the year.

Demand Response Program Impacts:

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

SCE's Demand Response forecast reflects ex-ante estimates based on the Load Impact Protocols[4]. The protocols governing the development of ex-ante load impacts were designed to help ensure that demand response impact estimates would be directly comparable with other resource alternatives (i.e., other DR resources, energy efficiency, renewables, and generation). The protocols require that the ex-ante load impact estimates be based on analysis of historical data whenever the existing data and characteristics of the program allow for such an approach. Analysis of historical program data is then employed to produce ex-ante load impact estimates that are subsequently used for resource adequacy, cost-effectiveness assessment and, by connection, resource planning.

Ex-ante load impacts reflect the fact that demand response load impacts vary as a function of weather, participant characteristics, changes in the number of program participants and other factors such as switch failure rates in order to provide an appropriate comparison with alternative resources under the same planning paradigm. Put differently, ex-post load impacts for any given year may differ from the load impacts that could be achieved during the low probability, extreme conditions under which many DR resources are likely to be used and for which they provide insurance value.

Describe assumptions about eligible population, participation rates, price elasticities, wholesale market conditions, and prices used to develop the projections.
Describe the method used to develop estimates of nondispatchable program impacts and the extent to which the forecast is consistent with recent program performance.

Statewide and Local DR Program Ex Post and Ex Ante Reports and Model Assumptions:

- Executive Summary: 2015-2025 Demand Response Portfolio of SCE, April 1, 2015
- SCE Final Load Impact Reports for Program Year 2014 (1 of 2), April 1, 2015
    - API, BIP, SDP, DBP, PTR, TOU
- SCE Final Load Impact Reports for Program Year 2014 (2 of 2), April 1, 2015
    - AMP, CBP, CPP, PLS

[3] Ordering Paragraph 1, Page 94

[4] 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).

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

- See Program Triggering Criteria Summary Table (pgs. 5-8, below).

<u>**Renewable and Distributed Generation Program Impacts:**</u>

Discuss how the estimates of energy and peak impacts for each program were derived. Detail the method and data used to project impacts of solar programs. Describe assumptions about eligible population, participation rates, price elasticities, fuel prices, wholesale market conditions, and prices used to develop the projections. Describe what criteria are used in deciding how to model customer decisions to use these facilities in peak shaving or base-load models.

The forecast of bypass co-generation is calculated from two lists of customers operating generating systems interconnected to the SCE grid for the purpose of meeting their own energy requirements: a thermal list and a solar list. Both customer lists identify those customers that have 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 103,500 operational solar systems ranging in size from 1KW to 1030 KW within the SCE service area. The forecast for 2014 includes solar facilities currently in the pipeline. The current forecast reflects SCE's best estimate of customer future adoption of solar distributed generation.

Both lists are used to estimate annual energy production by customer class, which is allocated to the months in the year. For 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 Time of Use (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 by month in order to produce a thermal by-pass consumption variable.

For the solar generation, the annual energy is calculated using the bypass capacity and annual capacity factors. The capacity factors are 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. Annual energy is distributed to the months of the year using a load shape based on daily hours of sunlight. The hourly loads are summed by month in order to produce a solar by-pass consumption variable for use in the econometric models. The monthly thermal and solar by-pass variables are summed for a single by-pass variable suitable for inclusion in the sales forecasting models.

Program Triggering Criteria Summary Table

Program	Type	Program Season	Available Annual Events/Hours	Available Monthly Events/Hours	Available Weekly Events/Hours	Available Daily Events/Hours	Available Trigger Criteria
Agricultural Pumping Interruptible (API)	Day Of	Year Round	Will Not Exceed Per Calendar Year: Interruption of 25 Times Duration of 150 Hours	Will Not Exceed Per Calendar Month: Duration of 40 Hours	Will Not Exceed Per Calendar Week: Interruption of 4 Times	Will Not Exceed Per Day: Interruption of 1 Time Duration of 6 Hours	•CAISO Warning, Stage 1, Stage 2, Stage 3, or Transmission Emergency • SCE Grid Control Center Discretion • Program Evaluation or System Contingencies
Base Interruptible Program (BIP)	Day Of	Year Round	Will Not Exceed Per Calendar Year: Duration of 180 Hours	Will Not Exceed Per Calendar Month: Interruption of 10 Times	N/A	Will Not Exceed Per Day: Interruption of 1 Time Duration of 6 Hours	•CAISO Warning, Stage 1, Stage 2, Stage 3, or Transmission Emergency • SCE Grid Control Center Discretion • Program Evaluation or System Contingencies
Capacity Bidding Program (CBP-DA)	Day Ahead	Year Round	N/A	Will Not Exceed Per Calendar Month: Duration of 30 Hours	N/A	Will Not Exceed Per Day: Interruption of 1 Time Duration of 8 Hours	15,000 Btu/kWh Heat Rate Criterion: High temperatures, Resource limitations, A generating unit outage, Transmission constraints, CAISO Alert or Warning Notice, SCE System Emergency, and/or Test events.

Capacity Bidding Program (CBP-DO)	Day Of	Year Round	N/A	Will Not Exceed Per Calendar Month: Duration of 30 Hours	N/A	Will Not Exceed Per Day: Interruption of 1 Time Duration of 8 Hours	15,000 Btu/kWh Heat Rate Criterion: High temperatures, Resource limitations, A generating unit outage, Transmission constraints, CAISO Alert or Warning Notice, SCE System Emergency, and/or Test events.
Demand Bidding Program (DBP)	Day Ahead	Year Round	N/A	N/A	N/A	Will Not Exceed Per Day: Interruption of 1 Time Duration of 8 Hours (12:00pm – 8:00pm)	At SCE's Discretion: CAISO Alert or Warning Notice, Day-Ahead load and/or price forecast, Extreme or unusual temperature conditions, SCE procurement needs, and/or Test events.
DR Contracts (DRC-DA)	Day Ahead	Varies	Varies by Contract	Varies by Contract	Varies by Contract	Varies by Contract	Varies by Contract
DR Contracts (DRC-DO)	Day Of	Varies	Varies by Contract	Varies by Contract	Varies by Contract	Varies by Contract	Varies by Contract
Save Power Day (SPD)	Day Ahead	Year Round	N/A	N/A	N/A	Will Not Exceed Per Day: Interruption of 1 Time Duration of 4 Hours (2:00pm – 6:00pm)	At SCE's Discretion: National Weather Service maximum recorded temperature at the Downtown Los Angeles site greater than 90 degrees by 2PM, CAISO Alert or Warning Notice, Forecasts of SCE system emergencies, Extreme or unusual temperature conditions, Day-Ahead load and/or price forecast.

Summer Advantage Incentive (SAI)	Day Of	Year Round	There will be 12 CPP Events per calendar year	N/A	N/A	Will Not Exceed Per Day: Interruption of 1 Time Duration of 4 Hours (2:00pm – 6:00pm)	At SCE's Discretion: National Weather Service maximum recorded temperature at the Downtown Los Angeles site greater than 90 degrees by 2PM, CAISO Alert or Warning Notice, Forecasts of SCE system emergencies, Extreme or unusual temperature conditions, Day-Ahead load and/or price forecast.
Summer Discount Plan - Residential (SDP-RES)	Day Of	Year Round	Will Not Exceed Per Calendar Year: Duration of 180 Hours	N/A	N/A	Will Not Exceed Per Day: Duration of 6 Hours	• CAISO Discretion for emergency purposes • SCE Grid Control Center Discretion • SCE's energy operations center discretion in response to high wholesale energy prices • Program Evaluation or System Contingencies • CAISO Alert or Warning Notice
Summer Discount Plan – Commercial (SDP-COM)	Day Of	Year Round	Will Not Exceed Per Calendar Year: Duration of 180 Hours	N/A	N/A	Will Not Exceed Per Day: Duration of 6 Hours	• CAISO Discretion for emergency purposes • SCE Grid Control Center Discretion • SCE's energy operations center discretion in response to high wholesale energy prices

							• Program Evaluation or System Contingencies • CAISO Alert or Warning Notice
Real-Time Pricing (RTP)	Non Dispatchable	Year Round	Hourly prices vary according to day type and temperature	Hourly prices vary according to day type and temperature	Hourly prices vary according to day type and temperature	Hourly prices vary according to day type and temperature	Applicable temperature for each type of day is the prior day's Los Angeles Downtown site maximum temperature as recorded by the National Weather Service.