BEFORE THE PUBLIC UTILITIES COMMISSION OF THE
STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769.	))))	Rulemaking 14-08-013 (Filed August 14, 2014)
And Related Matters	)))	Application 15-07-002 Application 15-07-003 Application 15-07-006
(NOT CONSOLIDATED)		
In the Matter of the Application of PacifiCorp (U901E) Setting Forth its Distribution Resource Plan Pursuant to Public Utilities Code Section 769.	))))	Application 15-07-005 (Filed July 1, 2015)
And Related Matters	)))	Application 15-07-007 Application 15-07-008

ADDENDA TO REVISED DISTRIBUTED ENERGY RESOURCE ASSUMPTIONS AND FRAMEWORK DOCUMENT OF PACIFIC GAS AND ELECTRIC COMPANY (U 39 E), SAN DIEGO GAS & ELECTRIC COMPANY (U 902 E), AND SOUTHERN CALIFORNIA EDISON COMPANY (U 338 E)

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June 28, 2017

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE
STATE OF CALIFORNIA

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ADDENDA TO REVISED DISTRIBUTED ENERGY RESOURCE ASSUMPTIONS AND FRAMEWORK DOCUMENT OF PACIFIC GAS AND ELECTRIC COMPANY (U 39 E), SAN DIEGO GAS & ELECTRIC COMPANY (U 902 E), AND SOUTHERN CALIFORNIA EDISON COMPANY (U 338 E)

Pursuant to the *Administrative Law Judge's Ruling Requiring Investor-Owned Utilities to File Assumptions and Framework Addendum, and For Parties to File Comments*, dated June 22, 2017, San Diego Gas & Electric Company (U 902 E), on behalf of itself and Pacific Gas and Electric Company (U 39 E) and Southern California Edison Company (U 338 E) (collectively, the "Joint IOUs"), hereby submits, for each of the Joint IOUs, an addendum to the Joint IOUs' Revised Distributed Energy Resource Assumptions and Framework Document filed on June 9, 2017.

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Respectfully submitted,

/s/ Jonathan J. Newlander

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On Behalf of the Joint IOUs: San Diego Gas & Electric Company (U 902 E), Pacific Gas and Electric Company (U 39 E), and Southern California Edison Company (U 338 E).

June 28, 2017

Addendum
San Diego Gas & Electric Company

Response ALJ Ruling to File an Assumptions and Framework Addendum

As directed by the Ruling, San Diego Gas & Electric Company (SDG&E) submits this addendum to the Revised Assumptions and Framework filed June 9, 2017 to provide additional information regarding the methodologies and assumptions used to develop the system-level forecast for those distributed energy resources (DERs) which diverge from the 2016 IEPR Energy Demand (CED 2016) forecast.

SDG&E notes that, as discussed during the DER GS workshops, the methodologies and assumptions used by the CEC in developing the values contained in the CED 2016 forecast are not public nor reviewed with the utilities. SDG&E cannot describe the internal mechanisms of those forecasting models, but rather it can only explain how it utilizes the results of those models in its own DER forecasts.

While SDG&E recognizes the value of consistency of system-level assumptions across all the planning processes, it also believes in the inherent value of planning to the best available information. The system-level assumptions explained below reflect the SDG&E's appreciation of adhering to the CEC's forecasted growth rates while simply adjusting those trajectories to current information that is not evaluated in the off-cycle IEPR years.

Behind-the-Meter Distributed Generation—Solar Photovoltaic (PV):

As mentioned above, SDG&E proposes not to use the values in the CED 2016 forecast because we believe our planning results will be more accurate if we use a 2016 base-year value that represents actual 2016 data.

Installed PV Capacity: SDG&E extracted data from its PV tracking data-base to develop a 2016 base-year value equal to the installed behind-the-meter (BTM) PV capacity interconnected as of December 31, 2016, and then applied the same year-to-year solar PV capacity growth rates as reflected in the CED 2016 forecast to produce a solar PV capacity forecast.

PV capacity at time of SDG&E's system peak: SDG&E uses a representative sample of solar generation meters which are used to derive hourly capacity factors. These capacity factors were then used to create an 8760 annual load shape for each year out to 2028. This information was passed to SDG&E's long-term hourly forecasting model, which produces an 8760 annual load shape for each year through 2028 and identifies when the annual system level peak occurs for each year. The last step in the process was to line up the 8760 load shapes for system load and solar PV generation and choose the solar generation that occurs at the same time as SDG&E's system level annual peak. This solar PV generation amount became the final PV demand at time of forecasted system peak demand. The system peak was then adjusted to reflect the offset of solar PV generation.

Electric Vehicles (EV):

As with SDG&E's PV forecast, SDG&E proposes not to use the values from the CED 2016 forecast because we believe our planning results will be more accurate if we use values that represent 2016 actual EV car stock and 2016 based estimates for vehicle energy use-per-day.

Car Stock: Car stock values were updated using proprietary data[1] for on-road registrations to represent actual EV car stock data through December 31, 2016. SDG&E used the same forecast of EV car stock as the CEC used in CED2016 demand forecast. SDG&E made no changes other than to extend the CEC's end point of forecasted car stock to the year 2028, which is the last year of the 2017 IEPR demand forecast period.

EV load impact at time of SDG&E system peak: To estimate the impact of EVs at the time of SDG&E's system peak, SDG&E used vehicle use-per-day estimates from SDG&E's SB 350 Transportation Electrification Application[2]. SDG&E then used the car stock data and use-per-day factors to develop a forecast of annual EV energy use. SDG&E has its own representative sample of separately-metered electric vehicles from which Smart-Meter data is extracted to develop an EV load profile/use-per-day hourly shape. SDG&E then created an 8760 annual EV hourly load shape for each year out to 2028. This information was passed to SDG&E's long-term hourly forecasting model, which produces an 8760 annual load shape for each year through 2028 and identifies when the annual system level peak occurs for each year. The last step in the process was to line up the 8760 load shapes for system load and the 8760 for EV charging consumption and choose the EV charging load that occurs at the same time as SDG&E's system level annual peak. This EV charging load value became the final EV demand at time of forecasted system peak demand.

Load-Modifying Demand Response:
As mentioned above, SDG&E proposes not to use the values in the CED 2016 forecast because we believe our planning results will be more accurate if we use the most values from the most recent demand response forecast.

Demand Response impact at time of system peak: The CED 2016 forecast is based upon demand response impacts contained in SDG&E's 2014 Portfolio Summary Load Impact Report, filed with the CPUC on April 1, 2015. SDG&E's proposed values for use in the 2017-2018 distribution planning process reflect merely replacing the CEC's estimates of load-modifying demand response impacts with updated impacts from SDG&E's 2016 Portfolio Summary Load Impact Report, filed with the CPUC on April 3, 2017. SDG&Es 2014 and 2016 respective Portfolio Summary Load Impact Reports are both publicly available.

Energy Storage (ES):
Among the five DER technology categories addressed in the Revised Assumptions and Framework document, energy storage is the only one that did not have a value in the CED 2016 forecast. Thus, in the strictest sense, SDG&E is not proposing to use values that diverge from the CED 2016 forecast. However, for the purpose of clarity, an explanation of the methodology and assumptions to develop SDG&E's ES forecast for customer-side energy storage is provided below.

[1] IHS/Polk Data. December 2016

[2] Filed with the CPUC January 20, 2017.

ES at time of SDG&E system peak: SDG&E developed an ES forecast by using the behind-the-meter (BTM) requirements legislated by AB2514. SDG&E used 16 MW, the sum of installed BTM ES projects at the end of 2016 as the starting point, and 30 MW in 2020, which was the AB2514 target for year 2020. A simple linear interpolation was then applied to determine ES values for years 2017, 2018, and 2019.

SDG&E did not extend the forecast beyond 2020 due to a very limited amount of historical data and experience forecasting this technology.

Energy Efficiency (EE):
SDG&E proposes to use CED 2016 forecast values for EE.

Addendum
Pacific Gas and Electric Company

ADDENDUM TO REVISED DER GROWTH SCENARIOS ASSUMPTIONS AND FRAMEWORK DOCUMENT

The following is responsive to the **ADMINISTRATIVE LAW JUDGE'S RULING REQUIRING INVESTOR-OWNED UTILITIES TO FILE ASSUMPTIONS AND FRAMEWORK ADDENDUM, AND FOR PARTIES TO FILE COMMENTS** issued June 22, 2017.

Ruling Directive: *We direct the IOUs to submit an addendum to the document that provides an explanation of any methodologies and assumptions that that are proposed to diverge from the demand forecast. The description of the methodology should explain the steps taken and the inputs used to calculate the system level DER growth forecast.*

PG&E Response: As shown on Table III-A and discussed in Section III-D of the Revised DER Growth Scenarios Assumptions and Framework document submitted on June 09, 2017, PG&E does not propose to diverge from the CEC's adopted 2016 IEPR California Energy Demand Forecast for load or DER adoption assumptions to be used as the basis for its 2017 distribution planning studies.

Addendum
Southern California Edison Company

Southern California Edison
Addendum to the Joint IOUs' Revised Assumptions and Framework Document

Administrative Law Judge Mason's June 22, 2017 Ruling requires that the investor-owned utilities (IOUs) file An Assumptions and Framework Addendum "that provides an explanation of any methodologies and assumptions that are proposed to diverge from the 2016 IEPR demand forecast." Below, in Section II, SCE provides an explanation of any methodologies and assumptions that are proposed to diverge from the 2016 IEPR demand forecast. This description provides an explanation of the steps taken and the inputs used to calculate the system level DER growth forecast. In addition, in Section I, SCE provides additional generalized discussion that is intended to explain its rationale for divergence.

Section I

1. SCE's Annual System level DER Forecast Refresh Occurs Annually in the Fall to Provide the Most Current Information for Facilitation of the Distribution Planning Process

Distributed Energy Resources (DERs) are at various stages of market development and adoption and are heavily influenced by latest policy decisions. SCE's system level DER forecasts are developed annually from September to November in order to provide updated DER forecasts into the distribution planning cycle. This timeframe allows SCE to factor in the latest historical adoption and any changes in policy from the prior forecast while also leveraging the latest IEPR development cycle. SCE's next distribution planning cycle will begin following the summer peak (which has historically occurred in September) and is anticipated to culminate in May 2018 in order to prepare for the following summer. DER forecasts play a critical role in distribution planning and SCE maintains the importance to use the most recent DER forecast within each planning cycle. With the advances of technology innovation and policy enabling increasing DERs adoption on the distribution system, DER forecasts have the potential to vary dramatically from year to year. If the most recent DER forecast is not utilized within each distribution planning cycle, it could result in unidentified grid needs placing the grid at risk.

2. SCE's 2017 Q4 DER forecast seeks to align with the 2017 IEPR rather than the 2016 IEPR

The system level DER forecasts in the 2016 IEPR are largely based on a forecast of DER from the 2015 IEPR and do not factor in the latest policy decisions or market outlook. The 2017 IEPR is currently underway to capture these factors as well as the latest trends in adoption. SCE intends to begin with the latest publicly available forecast (which is SCE's 2017 IEPR submittal) and factor in additional changes which will occur through the 2017 IEPR process rather than seeking to align with the 2016 IEPR. SCE is currently participating in stakeholder workshops and DAWG meetings at the CEC as part of the 2017 IEPR forecast development process where these updates to forecast methodology and assumptions are considered. SCE's updated DER forecasts will be developed from September to November 2017 based on SCE's need to provide timely information to reliably plan its distribution system while being informed by the 2017 IEPR.

3. SCE's System Level DER Forecast Benefits from Review in a Variety of Regulatory Forums

Upon completion, SCE's 2017 Q4 DER forecast will be presented to SCE's Procurement Review Group (PRG) where forecast changes (including assumptions and methodology) will be discussed and the results reviewed to provide transparency and inform stakeholders. SCE's annual system level DER forecasts are utilized in a variety of processes in addition to distribution planning and currently benefit from regulatory and stakeholder review in the following forums:

1) General Rate Case: SCE's annual system level DER forecasts are examined through testimony, workpapers, data requests, and hearings
2) ERRA forecast proceeding: SCE's annual system level DER forecasts are examined through testimony and workpapers
3) FERC Rate Case: SCE's annual system level DER forecasts are examined through workpapers and data requests
4) Integrated Energy Policy Report (IEPR): SCE's annual system level DER forecasts are examined through demand forms (including forecast inputs and outputs) and workpapers, are reconciled with CEC, and inform the final IEPR forecast; SCE's System level DER forecast methodologies are also filed in the demand forms as part of SCE's IEPR submittal
5) Bundled Procurement Plan: SCE's annual system level DER forecasts are examined through testimony, workpapers, and data requests

Section II

1. Load Modifying Demand Response (LMDR):

SCE's proposed source for LMDR assumptions in its upcoming 2017-18 distribution planning cycle is the 2016 Load Impact Protocols Report[1], which is consistent with what SCE filed in its 2017 IEPR submittal. SCE anticipates this source will also be utilized directly by the CEC in the 2017 IEPR. The 2016 Load Impact Protocols Report is developed using consistent methodology as earlier versions of the report but contains more recent assumptions. SCE is providing an overview of the methodology and assumptions below. For further information, a full copy of the report can be found in Attachment 1.

Explanation of Methodologies and Assumptions: The 2016 Load Impact Protocols Report was produced by Nexant. This report summarizes the load reduction capabilities of the Southern California Edison Co. (SCE) portfolio of demand response (DR) programs. It details the load impacts from 2016 events (ex post load impacts) and load reduction capabilities for 2017 through 2027 under normal (1-in-2 year) and extreme (1-in-10 year) system conditions (ex ante load impacts). This report adheres to the April 8, 2010 decision by the California Public Utilities Commission (CPUC) that requires a DR portfolio summary and specifies the format and content of the summary.[2]

SCE's Demand Response forecast reflects ex-ante estimates based on the Load Impact Protocols. 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

[1] The 2016 IEPR utilized the 2014 Load Impact Protocols Report.
[2] Decision (D.) 10-04-006

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.

Further detailed methodology surrounding the development of the LMDR estimates in SCE's 2017 IEPR submittal can be found in Attachment 1 that contains the full report developed by Nexant. Portions of the methodology and evaluation sections of the 2016 Load Impact Protocols Report are included below:

Section 3: Methodology

The 2016 evaluations address two main questions for DR programs: what demand reductions were delivered when resources were dispatched in 2016; and, what is the load reduction capability of each DR program? Ex post impacts reflect the demand reductions attained during actual events, but do not necessarily reflect the load reduction capability of the DR program. Historical ex post results are tied to specific conditions that occurred for that given event, including weather conditions, the number of participants who were dispatched, the mix of customers, and other factors such as switch failure rates. Several programs are dispatched strategically to address congestion in specific zones, test load response capabilities, or for economic reasons. Due to the absence of extreme weather or system emergencies in 2016, emergency resources such as BIP were only dispatched to test load reduction capabilities. In addition, the timing and duration of event dispatch varied across event days for many programs. As a result, the impacts for individual event days are not necessarily representative of the full program capability. Ex ante impacts reflect the load reduction capability of a DR program for each month under a weather conditions associated with standard 1-in-2 and 1-in-10 system peaking conditions. They reflect the reduction that can be attained if all enrolled participants are dispatched under the weather conditions that drive system planning. Whenever possible, ex ante load impacts are grounded in analysis of historical load impact performance. These estimates are used in assessing alternatives for meeting peak demand, cost-effectiveness comparisons, and long-term planning.

Section 3.2 Overview of Evaluation Methods

The methods used to estimate ex post and ex ante load impacts for each of the DR programs in the SCE portfolio are conceptually similar. Nearly all of the 2016 evaluations relied on, or partially relied on, regression analysis to estimate a model reflecting the relationship between customer whole-premise or end-use load and key determinants of the variation in energy use over time, such as weather and time-of-day, day-of-week, and seasonal patterns that reflect the normal pattern of business or household operations. In some cases, a matched control group was used to estimate reference load for the purpose of deriving load impacts. For those, load is not modeled as a function of weather and time-of-day for the purpose of determining reference *load; rather, reference load for the treatment group is simply the observed load of the control group, minus the small difference between treatment and control loads observed on nonevent days. Nevertheless, reference load models are still required even in this setting for the purpose of ex ante load impact estimation. The exception in 2016 is the PLS evaluation, which had a single installed project at the time of the evaluation. The PLS evaluation primarily relies on building simulation modeling to develop ex ante load impacts given further assumptions about the timing, geographic location, project size, and budget for the program across the ex ante forecast horizon.*

Regression models are based on historical hourly or sub-hourly electricity use data for customers who have participated in the DR programs. Each model or set of models is used to estimate the reference load for an average customer enrolled in a program, which represents what customers would be expected to use in the absence of an event on days in which program events either were called (for ex post impact estimation) or have a high probability of being called (for ex ante impact estimation). For RTP, the methods were slightly different. RTP reference loads represent what the average customer would use on a specific day if they faced the otherwise applicable tariff, TOU-8, rather than the RTP tariff.

In most instances, ex post load impacts were estimated by comparing the reference level energy use in each hour with the estimated load with DR in the hour on each event day. For ex ante estimation, predicted energy use in each hour was estimated under the assumption that an event occurred and also under the assumption that it did not occur, while everything else (e.g., weather, day-of-week effects) was held constant at values representative of a typical event day or monthly system peak day.

At a more technical level, three general approaches were used to estimate the regression models:

- *Individual Customer Time Series Regressions: This method works well for event based programs with numerous events and for programs with substantial variation in the drivers of load response or load shifting. This approach is also useful for programs with substantial differences in the magnitude and load patterns of customers, which is more typical among large customers. The coefficients vary at the customer level. The regressions do not necessarily explain individual customer behavior perfectly, but on aggregate they explain most of the program level variation in loads. Importantly, individual customer regressions can be employed to describe the distribution of customer load reductions as well as the distribution of percent load reductions. They can also be used to describe impacts for segments of the participant population. The key limitation to individual customer regressions is that they have no control group, and therefore they have limited ability to account for non-observable variations.*

- *Aggregate Time Series Regressions: Similar to the individual customer regression approach, but rather than estimating reference loads and load impacts for individual customers, estimates are made for groups of customers taken in aggregate.*

- *Panel Regressions: This method is particularly suitable when control groups are available, or sample sizes are sufficient for the territory, but inadequate for smaller segments such as local capacity areas. A key strength of panel regressions is the ability to control for certain omitted or unobservable variables. While panel regressions can* *increase the accuracy of impact estimates for the average customer, they cannot be employed to describe the distribution of impacts among the participant population. Importantly, panel regressions cannot control for customer characteristics that interact with occupancy and or weather unless those variables are explicitly included.*

The regression models used to predict the reference load were developed with the primary goal of accurately predicting average customer load given the time of day, day of week, temperature, and location of each customer and predicting load reductions under different temperature conditions. The focus was on the accuracy of the prediction and the validity of load impact estimates. The regression equations used to model load patterns and estimate load impacts for each program are detailed in Appendix B[3]*.*

2. **Solar Photovoltaics:**
SCE intends to utilize its 2017 Q4 DER forecast, which will be informed by the 2017 IEPR, in its upcoming 2017-18 distribution planning cycle. In developing this forecast, SCE will begin with the 2017 IEPR submittal, and update the forecast to account for additional historical adoption information and any State or Federal policy decisions which may have occurred since the prior forecast. The methodology and assumptions for SCE's 2017 Q4 Forecast will be coordinated with the CEC through the 2017 IEPR process which is currently underway. Given SCE's forecasting timeline, SCE's updated forecast is anticipated to be complete in Q4 of 2017. The methodology and assumptions for Solar PV in SCE's 2017 IEPR submittal, which will serve as the starting point for SCE's updated forecast, are included below.

Explanation of Methodologies and Assumptions

SCE models the residential adoption of solar photovoltaic through a generalized Bass diffusion model. The Bass diffusion model is a standard technology adoption model originally developed in 1969 which describes the process of how new technologies are adopted in a population.[4] The model considers the way in which current and potential adopters interact. Adopters are classified as either innovators or imitators. The Bass Model can be generally described by the following equations:

$$\frac{f(t)}{1-F(t)} = p + qF(t)$$

The hazard function: conditional probability

Rate of adoption by innovators

Rate of adoption by imitators is a function of cumulative adoption

$$Y(t) = mF(t)$$

$$S(t) = pm + (q-p)Y(t) - \left(\frac{q}{m}\right)[Y(t)]^2$$

- f(t) is the density function of time of adoption

[3] Attachment 1 - Appendix B.
[4] Bass, Frank. "A New Product Growth for Model Consumer Durables." Management Science. Vol. 15, Issue 5, 1969.

- F(t) is the cumulative function for time of adoption
- m is the total number of ultimate adopters
- Y(t) is the cumulative adoption function
- S(t) is the per-period adoption function (sales)

SCE utilizes the generalized Bass Model which (1) includes decision variables, (2) has a closed-form solution in the time domain and, (3) reduces to the Bass Model as a special case under plausible regularity conditions for the decision variables.[5] The equations for the generalized Bass diffusion model are:

Mapping function

$$\frac{f(t)}{1-F(t)} = [p + qF(t)]x(t)$$

The hazard function: conditional probability

Rate of adoption by innovators

Rate of adoption by imitators is a function of cumulative adoption

$$Y(t) = mF(t)$$

$$S(t) = x(t)m\frac{\left[\frac{(p+q)^2}{p}\right]e^{-(X(t)-X(0))(p+q)}}{\left(1+\left(\frac{q}{p}\right)e^{-(X(t)-X(0))(p+q)}\right)^2}$$

- Y(t) is the cumulative adoption function
- S(t) is the per-period adoption function (sales)
- X(t) is the cumulative mapping function
- m represents the total number of ultimate adopters
- f(t) is the density function of time of adoption
- F(t) is the cumulative function for time of adoption
- x(t) maps decision and policy variables

SCE's estimates the technical potential based on NREL's "Rooftop Solar Photovoltaic Technical Potential in the United States: A Detailed Assessment," (Jan. 2016) which provides a detailed study of major metropolitan regions including Los Angeles, in order to build a zip code level estimation of technical potential.[6] Based on this assessment 91% of small buildings in SCE territory meet the technical potential. The SCE model uses percentage changes in the price-per-Watt-AC of installation, adjusted for the Federal Investment Tax Credit, as its explanatory variable. Bloomberg New Energy Finance (BNEF) provided SCE's historical and forecast solar installation price series from 2010-2030.[7] The compound monthly growth rate was used to

[5] Bass, Frank M., Trichy V. Krishnan, Dipak C. Jain. "Why the Bass Model Fits Without Decision Variables." Marketing Science. Vol. 13, No. 3, Summer 1994.
[6] Available at http://www.nrel.gov/docs/fy16osti/65298.pdf
[7] "H1 2016 US PV Market Outlook: Boom Without a Bust." Bloomberg New Energy Finance. June 7 2016.

extend this series back to 2000. Residential solar photovoltaic adoption history comes from SCE's internal net energy meter (NEM) database.

As this model is essentially a regression, expected policy changes in the future that are not reflected in the history require post-model adjustment. Changes to building code require that all new houses constructed starting in 2020 be "zero net energy" (ZNE). Additional estimates were performed to account for future PV installation in compliance with this mandate. As some building developers are already starting to implement this mandate, a gradual compliance rate culminating in 90% in 2020 was assumed. SCE's internal new residential meter forecast was used as the basis of the new homes. From 2016 to 2018, the annual incremental adoptions were decreased by 4.55% to reflect the effect of the implementation of a two-tier rate scheme.

SCE's Solar PV forecast is largely dominated by residential sector with the non-residential sector representing ~13% of the incremental growth from 2017-2028. Given the limited impact of the non-residential sector on the overall forecast SCE currently employs a basic approach. For this portion, SCE utilizes historical trend analysis combined with expert judgment to project the non-residential solar PV growth. As this sector grows SCE may move to a more complex model.

3. **Energy Storage:** SCE did not submit a separate BTM energy storage forecast as part of its IEPR submittal and therefore SCE intends to maintain consistency with the current statewide planning assumptions by utilizing the 2017 CPUC ACR containing Assumptions and Scenarios for use in long term planning in 2017 with emphasis on CAISO's 2017-18 Transmission Planning Process. This document contains SCE's currently contracted BTM ES procurement which exceeds the BTM ES targets set forth in AB2514 and is included as Attachment 2.[8] SCE will continue to monitor the status of the contracts below prior to incorporation into its 2017-18 distribution planning cycle.

[8] http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M172/K519/172519400.PDF

Table 6: Locational Information for SCE's Energy Storage Resources

SCE's Energy Storage Projects Locational Information by Busbar & Attributes (MW)						
LCR RFO 264 MW	**Project**	**Storage MW**	**Product Type**	**Locational Information**	**Bus ID**	
	Ice Bear	28.64	ES BTM PLS (customer-side)	N/A (Distributed)		
	AES	100	IFOM (distribution)	**Point of Interconnection:** 230kV bus at the Alamitos A-Bank Substation **Bus Name:** ALMITOSW **Bus Number:** 24007		
	Stem	85	ES BTM (customer-sde)	N/A (Distributed)		
	Hybrid Electric	50	ES BTM (customer-sde)	N/A (Distributed)		
2016 ACES RFO/RFP	**Project**	**Storage MW**	**Product Type**	**Locational Information**		
	Powin	2	IFOM (distribution)	**Point of Interconnection:** 12kV Virgo Distribution line (Santiago A Bank Substation)	66 kV +H11:H35Bus Name: SANTIAGO 66 kV Bus Number: 24133	*No bus number for 12 kV Bus. 66 kV bus where B-station that feeds circuit is located used
	Western Grid [2]	5	IFOM (distribution)	**Point of Interconnection:** Wakefield Petit 16 kV Distribution line (Santa Clara A Bank Substation)	66 kV Bus Name: S.CLARA 66 kV Bus Number: 24127	
	AltaGas	20	IFOM (distribution)	**Point of Interconnection:** Ganesha Simpson 66kV line Distribution line (Chino A Bank Substation)	66 kV Bus Name: CHINO 66 kV Bus Number: 24024	*No bus number for 66 kV Transmission Line Tap. Chino 66 kV bus utilized
	Project	**Storage MW**	**Product Type**	**Locational Information**		
2016 ACES DBT	Tesla	20	IFOM (distribution)	**Point of Interconnection:** Mira Loma A Bank Substation	66 kV Bus Name: MIRALOMW 66 kV Bus Number: 24210	
PRP 2	**Project**	**Storage MW**	**Product Type**	**Locational Information**		
	AMS CTEC 1-5	40	ES BTM (customer-sde)	N/A (Distributed)		
	Convergent OCES 1-3	35	IFOM (Transmission)	**Point of Interconnectio:** Chestnut 66kV bus out of Johanna 220/66kV substation	66 kV Bus Name: JOHANNA 66 kV Bus Number: 24207	
	Nextera OCES 1	8.5	ES BTM (customer-sde)	N/A (Distributed)		
	Nextera OCES 2	1.5	ES BTM (customer-sde)	N/A (Distributed)		
	SEF1	5	ES BTM (customer-sde)	N/A (Distributed)		
	Valencia Energy Storage	10	IFOM (distribution)	**Point of Interconnection:** Aquarius 12 kV circuit Santiago 220/66kV substation	66 kV Bus Name: SANTIAGO 66 kV Bus Number: 24133	*No bus number for 12 kV Bus. 66 kV bus where B-station that feeds circuit is located used
	HEJF1-2	15	IFOM (distribution)	**Point of Interconnection:** 12 kV bus at the Johanna substation	66 kV Bus Name: JOHANNA 66 kV Bus Number: 24207	*No bus number for 12 kV Bus. 66 kV bus where B-station that feeds circuit is located used
	NRG Hybrid 1-5 [1]	10	ES BTM (customer-sde)	N/A (Distributed)		
Bilateral	**Project**	**Storage MW**	**Product Type**	**Locational Information**		
	SCE EGT - Grapeland	10	IFOM (Transmission)	**Point of Interconnection:** Integrated with SCE's Grapeland Peaker	66 kV Bus Name: ETIWANDA 66 kV Bus Number: 24055 13.8 kV Bus Name: ETWPKGEN 13.8 kV Bus Number 29305 Project will share same 13.8 kV Bus where exsting peaker is located.	
	SCE EGT - Center	10	IFOM (Transmission)	**Point of Interconnection:** Integrated with SCE's Center Peaker	66 kV Bus Name: CENTER 66 kV Bus Number: 24203 13.8 kV Bus Name: CTRPKGEN 13.8 kV Bus Number 29308 Project will share same 13.8 kV Bus where exsting peaker is located.	
ES RFO 16.3 MW	**Project**	**Storage MW**	**Product Type**	**Locational Information**		
	Stanton Energy Reliability Center	1.3	RA Only (distribution)	**Point of Interconnection:** Barre Substation **Bus Name:** BARRE **Bus Number:** 24201		
	Western Grid	10	RA Only (distribution)	**Point of Interconnection:** Wakefield Petit 16 kV Distribution line (Santa Clara A Bank Substation) **Bus Name:** S.CLARA **Bus Number:** 24127		
		5	RA Only (distribution)			

4. **Electric Vehicles:** SCE intends to utilize its most recent forecast which will be informed by the 2017 IEPR in its upcoming 2017-18 distribution planning cycle. Given SCE's forecasting timeline, this forecast is anticipated to be complete in Q4 of 2017. The methodology and assumptions for Electric Vehicles in SCE's 2017 IEPR submittal, which will serve as the starting point for SCE's updated forecast are included below.

Explanation of Methodologies and Assumptions

SCE forecasts future transportation electrification load growth for light duty EV load. As a nascent and dynamic market affected by several exogenous variables such as manufacturer supply, local, state, and federal policy, and technology advancement, plug-in electric vehicle (PEV) forecasting is treated separately as a positive load contributor in SCE's system DER forecast.

For light duty SCE obtained three forecasts from Navigant (conservative, base, and high) specific to SCE's territory. The forecasts contain EMission FACtors (EMFAC) categories for light-duty automobiles (LDA) and light-duty trucks (LDT1, LDT2). These forecasts were adjusted downward by approximately 20,000 to align with historical adoption numbers through 2016 using Polk/DMV registration data. The forecast in SCE's 2017 IEPR submittal is the resulting adjusted conservative case from Navigant. Once population numbers are determined for each year, several variables are then applied to determine hourly, daily, and annual electricity load shapes.[9] The Navigant report materials provided in Attachments 3a and 3b provide further explanation of the detailed methodology and assumptions utilized.

5. **Energy Efficiency:** As inputs into its upcoming 2017-18 distribution planning cycle SCE's methodology requires a two-pronged approach that uses both C&S and EE savings. For C&S, intends to directly utilize the CEC's AAEE Codes and standards savings consistent with the 2016 IEPR.[10] For EE programs, SCE intends to start with the CPUC's 2015 EE Potential and Goals Study (P&G Study) consistent with SCE's 2017 IEPR submittal. SCE also intends to evaluate the 2017 EE Potential and Goals Study for use in the upcoming distribution planning cycle pending availability of the final study.

   The P&G Study supports four related efforts:
   1. Inform the CPUC as it proceeds to adopt goals and targets, providing guidance for the next IOU energy efficiency portfolios.
   2. Guide the IOUs in portfolio planning and the state' principal energy agencies in forecasting for procurement, including the planning efforts of the CPUC, California Energy Commission (CEC), and California Independent System Operator (CAISO).
   3. Inform strategic contributions to greenhouse gas reduction targets.
   4. Develop metrics for the CPUC's Energy Efficiency Strategic Plan update.

   CPUC Decision 15-10-028 supplied EE program goals to California's IOU's directly using the output of the P&G Study. Using this decision, SCE's team of EE experts designed a portfolio of EE program savings that met or exceed these goals. Since SCE's EE Programs are designed and built to meet or exceed the CPUC's EE Goals, and not AAEE, SCE strongly believes that the EE Potential and Goals study is the best starting point to appropriately reflect SCE's anticipated EE Program Savings.

   Explanation of Methodologies and Assumptions for EE Savings

   SCE's 2017 IEPR submittal contained forecasted energy and the coincident peak impacts captured (2015) or expected to be captured by SCE EE Programs. The source documentation for SCE's EE Program savings was the 2015 EE Potential and Goals Study. As the study culminated in 2024, 2025 through 2028 values were estimated using the CAGR from 2020-2024.

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[9] SCE develops assumptions for electric vehicle miles traveled per day (eVMT), vehicle-type mix (e.g., battery electric, plug-in hybrid 15, plug-in hybrid 40), vehicle and charger efficiencies, customer TOU adoption, and customer charging behavior.

[10] SCE will evaluate the ability to utilize the 2017 IEPR AAEE C&S numbers in the 2017 Q4 Forecast pending their ability

The 2015 EE Potential and Goals Study was conducted by the Navigant team on behalf of the CPUC. The study analyzed the energy and demand savings potential in SCE service territory during the post 2015 EE portfolio planning cycle and includes results for SCE. The full 2015 EE Potential and Goals Study is included in Attachment 4. Excerpts from the report detailing the purpose and modeling assumptions are included below.

2.1 Modeling

The primary purpose of the 2015 Study is to provide the CPUC with information and analytical tools to engage in goal setting for the next IOU energy efficiency portfolio. In addition, this study informs forecasts used for procurement planning. The model itself does not establish any regulatory requirements. This section provides a brief overview of the modeling methodology used for the 2015 Potential and Goals Study. The modeling methodology remains the same as that used in the 2013 Study. For more information on the specific methodology for different parts of the model, please reference the 2013 Study report.

The 2015 model forecasts potential energy savings from a variety of sources within six distinct sectors: Residential, Commercial, Agricultural, Industrial, Mining, and Street Lighting. Within some or all of the sectors, sources of savings include:

- *» Emerging Technology – Emerging technologies were examined for the Residential, Commercial, and Street-lighting sectors. These sectors are modeled using individual measures for specific applications.*
- *» Behavior - For the purposes of this study, the Navigant team defines behavior-based initiatives as those providing information about energy use and conservation actions, rather than financial incentives, equipment, or services.*
- *» Financing - Financing has the potential to break through a number of market barriers that have limited the widespread market adoption of cost-effective energy efficiency measures. The PG Model estimates the incremental effects of introducing energy efficiency financing on energy efficiency market potential and how shifting assumptions about financing affect the potential energy savings.*
- *» Whole Building - In the case of whole-building initiatives, the “measure” is characterized for the building retrofit or house retrofit rather than for specific technology or end uses. Whole building initiatives are modeled for the Residential and Commercial sectors.*
- *» Low Income – The methodology for the low-income sector remains unchanged from the 2013 Study. Data was updated to reflect the most recent information available from the CPUC regarding savings per participant and forecasted participants.*
- *» Codes and Standards - Codes and standards are implemented and enforced either by federal or state governmental agencies. Codes regulate building design, requiring builders to incorporate high-efficiency measures. Standards set minimum efficiency levels for newly manufactured appliances. The Navigant team assessed energy savings potentials for three types of C&S:*
    - *o Federal appliance standards*
    - *o Title 20 appliance standards*
    - *o Title 24 building energy efficiency codes*

Consistent with the 2013 Study, the 2015 PG Model forecasts three levels of energy efficiency potential (technical, economic, and market) as described earlier in section 1.3 To estimate the market potential for the Residential, Commercial, Mining, and Street Lighting sectors, the model employs a bottom-up dynamic Bass Diffusion approach to simulate market adoption of efficient measures. The Navigant team calculated energy efficiency potential in the industrial and agricultural sectors using a top-down supply curve approach as detailed in the 2013 Study report. Like the 2013 PG model, the 2015 model was developed in the Analytica software platform. The inputs and user interface are designed for customizability and ease of use.

Attachment 1

SCE 2016 Compliance Filing Pursuant to

Load Impact Protocol Filing Requirements

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Order Instituting Rulemaking To Enhance The Role Of Demand Response In Meeting The State's Resource Planning Needs And Operational Requirements.	R.13-09-011 (Filed September 19, 2013)

SOUTHERN CALIFORNIA EDISON COMPANY'S (U 338-E) COMPLIANCE FILING PURSUANT TO LOAD IMPACT PROTOCOL FILING REQUIREMENTS

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Dated: **April 3, 2017**

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Order Instituting Rulemaking To Enhance The Role Of Demand Response In Meeting The State's Resource Planning Needs And Operational Requirements.	R.13-09-011 (Filed September 19, 2013)

SOUTHERN CALIFORNIA EDISON COMPANY'S (U 338-E) COMPLIANCE FILING PURSUANT TO LOAD IMPACT PROTOCOL FILING REQUIREMENTS

Pursuant to the Rules of Practice and Procedure of the California Public Utilities Commission (Commission), as well as the load impact protocol requirements adopted in Commission Decision (D.)08-04-050, as modified by D.10-04-006, Southern California Edison Company (SCE) hereby submits for filing[1] the executive summary report of its annual study of demand response (DR) activities and accompanying summary tables. D.08-04-050, as modified by D.10-04-006, directs the California investor-owned utilities (IOUs) to file and serve the executive summaries of their reports, along with summary tables of each DR activity, annually on April 1 of each year.[2] The executive summary and accompanying summary tables for SCE's April 1, 2016 DR load impact reports, entitled "Southern California Edison's 2016 Demand Response Portfolio Summary Report" (Executive Summary), are attached hereto as **Appendix A**.

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1 Pursuant to the March 13, 2014 Email Ruling of ALJ Hymes directing the utilities to file their annual load impact reports in R.13-09-011 as the successor proceeding to R.07-01-041.

2 D.10-04-006, Ordering Paragraph (OP) 1, modifying OP 4 of D.08-04-050.

SCE has posted the public versions[3] of the final load impact reports and supporting tables for the SCE-specific DR programs on its website. In addition to these SCE-specific DR programs, SCE has posted the public versions of the final reports for the statewide DR programs, as required by OP 11 of D. 12-04-045. Because the files for these reports are quite large and voluminous, SCE is serving a Notice of Availability (NOA) for both the SCE-specific and statewide reports and tables on the Service List for this proceeding, as well as the members of the Demand Response Measurement Evaluation Committee (DRMEC). A copy of the NOA is attached hereto as **Appendix B**.[4] SCE's NOA contains the titles of the individual program reports, with instructions for accessing the documents on SCE's website and/or requesting a physical copy of the documents from SCE.

In addition to serving this filing on the Service List and members of the DRMEC, SCE is also providing the Commission's Energy Division with a copy of the complete reports, as required by D. 08-04-050, as modified by D.10-04-006. The confidential version of the complete reports provided to the Commission and Commission Staff, as well as the Energy Division, will include a Confidentiality Declaration in compliance with D.16-08-024 that provides a general description of the information that is confidential, the location of the confidential information, and the basis for confidential treatment. A copy of this Confidentiality Declaration is attached hereto as **Appendix C**.

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[3] SCE notes that some of the information contained in certain reports or supporting tables (for both the SCE-specific and Statewide reports) is confidential. For the public versions of such reports and tables, documents that are confidential in-part will be redacted, and documents that are wholly confidential will be replaced with a "placeholder" document.

[4] SCE notes that D.08-04-050, as modified by D.10-04-006, does not require the IOUs to file the individual reports with the CPUC. The "summary tables" required to be filed in compliance with OP 4 of D. 08-04-050, as modified by D.10-04-006, are attached as appendices to the Executive Summary, and are part of **Appendix A** hereto.

Respectfully submitted,

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April 3, 2017

Appendix A

Southern California Edison Company's PY2016 Demand Response Portfolio Summary Report

Southern California Edison 2016 Demand Response Portfolio Summary Report

April 1, 2017

Prepared for
Southern California Edison Co.

Prepared by
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CALMAC Study ID SCE0410

Confidential information is redacted and denoted with black highlighting: [redacted]

Table of Contents

1 Introduction

This report summarizes the load reduction capabilities of the Southern California Edison Co. (SCE) portfolio of demand response (DR) programs. It details the load impacts from 2016 events (ex post load impacts) and load reduction capabilities for 2017 through 2027 under normal (1-in-2 year) and extreme (1-in-10 year) system conditions (ex ante load impacts). This report adheres to the April 8, 2010 decision by the California Public Utilities Commission (CPUC) that requires a DR portfolio summary and specifies the format and content of the summary.[1]

SCE's DR portfolio is comprised of 15 DR resources listed in Table 1-1. Two programs listed in the CPUC decision are not included in this report. Optional Binding Mandatory Curtailment (OBMC) is a program of last resort, triggered immediately prior to rolling blackouts and is not considered a DR program by SCE. The Scheduled Load Reduction Program (SLRP) is also not included because there are no participants in the program and no enrollments are projected for future years.

Table 1-1: Categorization of SCE DR Programs

Emergency	Price-responsive	Demand Response Aggregator-managed	SmartConnect®-enabled	Nonevent Based
▪ Base Interruptible Program with 15-minute advance notice (BIP-15)	▪ Summer Discount Plan – Commercial (SDP-C)	▪ Capacity Bidding Program with Day-ahead Notification (CBP-DA)	▪ Save Power Day (SPD) - with enabling technology	▪ Real Time Pricing (RTP)
▪ Base Interruptible Program with 30-minute advance notice (BIP-30)	▪ Summer Discount Plan - Residential (SDP-R)	▪ Capacity Bidding Program with Day-of Notification (CBP-DO)		▪ Permanent Load Shifting (PLS)
▪ Agricultural and Pumping Interruptible Program (AP-I)	▪ Default Critical Peak Pricing (CPP) - Large	▪ Aggregator Managed Programs (AMP)		
	▪ Default Critical Peak Pricing (CPP) - Medium			
	▪ Default Critical Peak Pricing (CPP) - Small			
	▪ Demand Bidding Program (DBP)			

[1] Decision (D.) 10-04-006

The following reports from the 2016 program evaluations for all of SCE's DR resources were filed with the CPUC by SCE on April 3, 2017 in accordance with the CPUC Load Impact Protocols[2] (Protocols):

- Collins, Cummings, and Bell. 2016 Load Impact Evaluation of Southern California Edison's Agriculture and Pumping Interruptible Program. Final Report. April 1, 2017.
- Potter and Ciccone. 2016 Load Impact Evaluation of California Statewide Base Interruptible Program. Final Report. April 1, 2017.
- Bell, Blundell, Ciccone, Cummings. 2016 Load Impact Evaluation of California's Statewide Nonresidential Critical Peak Pricing Program and SCTD Commercial Thermostats. Final Report. April 1, 2017.
- Nguyen, Duer, Parmenter, Marrin. 2016 Statewide Load Impact Evaluation of California Aggregator Demand Response Programs: Ex Post and Ex Ante Load Impacts. April 1, 2017.
- Hansen and Huegerich. 2016 Load Impact Evaluation of California Statewide Demand Bidding Programs (DBP) for Non-Residential Customers: Ex-Post and Ex-Ante Report. April 1, 2017.
- Schellenberg, Collins, and Flaherman. 2016 Load Impact Evaluation of Southern California Edison's Peak Time Rebate Program. Final Report. April 1, 2017.
- Schellenberg, Collins, and Stansell. 2016 Load Impact Evaluation of Southern California Edison's Summer Discount Plan. Final Report. April 1, 2017.
- Bell and Gai. 2016 Load Impact Evaluation of the California Statewide Permanent Load Shifting Program. Final Report. April 1, 2017.

Ex post load impacts are summarized for all programs that experienced an event in 2016. Ex post load impacts determine what happened over an historical period, based on the conditions that were in effect during that time. Because historical performance is tied to past conditions such as weather, price levels, and dispatch strategy (e.g., localized dispatches), ex post load impacts may not reflect the full option value of a DR resource.

Ex ante load impacts are summarized for each program and for SCE's DR portfolio as a whole. Portfolio impacts summarize the load reduction that can be expected from all of SCE's DR programs if jointly dispatched. In other words, they avoid double counting load impacts from dually enrolled customers. Ex ante load impacts are forward-looking and are designed to reflect the load reduction capability of a DR resource under a standard set of conditions. Ex ante load impacts are estimated under normal (1-in-2 year) and extreme (1-in-10 year) weather conditions. Estimates have also been developed for two sets of weather conditions, one based on SCE-specific peaking conditions and one based on CAISO system peaking conditions. Estimates contained in the main body of this report are based on SCE-specific conditions. Estimates based on CAISO-specific peaking conditions are contained in the appendices.

This report begins with a description of the SCE DR programs covered in this executive summary, including current and forecasted program enrollment. The program overview section

[2] See CPUC Rulemaking 07-01-041, D.08-04-050, "Adopting Protocols for Estimating Demand Response Load Impacts" and Attachment A, "Protocols."

is followed by a summary of the methods employed in analyzing the ex post and ex ante load impacts for each program. The next two sections summarize the ex post and ex ante results for each program as well as the portfolio of programs collectively. The final section summarizes the recommendations contained in the 2016 program evaluation reports. Appendix A shows the proxy days used to develop ex ante weather conditions for SCE. Appendix B describes the regression specifications that were used in modeling customer load or estimating load impacts for each program evaluation. Appendices C through J contain the ex ante load impact tables that must be included in this portfolio summary. Finally, Appendix K presents SCE's demand response program capacity that can be used as reliability-based resources in years 2017 through 2027, as calculated per guidelines established by CPUC D.10-06-034.

2 Overview of Demand Response Programs

SCE's current programs can be assigned to one of five categories: reliability; price responsive; demand response aggregator managed; SmartConnect® -enabled programs; and nonevent based programs. In general, reliability programs are called when operating reserves are limited, either immediately prior to or during system emergencies. Price responsive programs can be called based on market conditions defined by market prices, generator heat rates, temperature, or other indicators. Price responsive in this context does not necessarily mean that customers in these programs face time-varying prices—it means that these programs can be dispatched in response to economic conditions in the wholesale market. In aggregator-managed programs, aggregators contract with commercial and industrial customers and deliver load reductions to the utility. Each aggregator forms a portfolio of individual customer accounts and nominates specific accounts for either an existing DR program such as the Capacity Bidding Program or for meeting contractual load reduction obligations. Nonevent based programs are not dispatchable, but provide explicit incentives or time-varying pricing to customers who shift or reduce loads during peak periods. SmartConnect®-enabled programs refer to programs that are tied to SCE's rollout of smart meters.

2.1 Reliability Programs

Reliability programs are called when operating reserves are limited, either immediately prior to or during system emergencies.

2.1.1 Base Interruptible Program

Each of California's three electric investor-owned utilities (IOUs) offer the Base Interruptible Program (BIP). BIP is a tariff-based, emergency-triggered demand response program that CAISO can dispatch for system emergencies. The IOUs can also dispatch BIP for local emergencies or on a measurement and evaluation event basis to verify the program's load reduction capability. The program can be dispatched both for instances when electricity system demand approaches installed generation capacity (a resource shortage) or in response to emergencies due to transmission and generation outages. Customers enrolled in BIP receive incentive payments in exchange for committing to reduce their electricity demand to a contractually-established level referred to as the Firm Service Level (FSL). Participants who fail to reduce load to the FSL are subject to a financial penalty assessed on a kWh basis. SCE differentiates BIP payment levels based on the timing in which the customer responds to dispatch notification; customers can commit to providing load reductions within 15 or 30 minutes of notification. The load impacts for both options are summarized in this report. BIP was integrated into the CAISO wholesale market in 2015.

2.1.2 Agricultural and Pumping Interruptible Program

The Agricultural and Pumping Interruptible (AP-I) program provides a monthly credit to eligible agricultural and pumping customers for allowing SCE to temporarily interrupt electric service to their pumping equipment during CAISO or other system emergencies. Agricultural and pumping customers with a measured demand of 37 kW or greater, or with at least 50 horsepower of connected load per service account, are eligible to participate in the AP-I program. Participating customers must already be served under an agricultural and pumping rate schedule. When an interruption is deemed necessary and is allowed under the terms of the tariff, SCE sends a signal to the load control device installed on a customer's pumping equipment. The signal automatically turns off the equipment for the entire duration of the interruption event. The number of interruptions cannot exceed 1 per day, 4 per week, and 25 per calendar year. The duration of an interruption cannot exceed 6 hours and the total hours of interruption cannot exceed 40 per calendar month or 150 per calendar year. In exchange for allowing SCE to interrupt pumping service during emergencies, AP-I customers receive a monthly credit. For customers on time-of-use (TOU) rates, the credit is based on measured peak and mid-peak electricity demand. For customers that are not on a TOU rate, the credit is based on monthly usage. AP-I was integrated into the CAISO wholesale market in 2015.

2.2 Price Responsive Programs

The distinguishing feature of price-responsive programs is that they are dispatched based on economic criteria rather than solely for emergency conditions. SCE has the option of dispatching these programs when economic conditions—defined by market prices, generation heat rates, temperature, or other market indicators—are met.

2.2.1 Summer Discount Plan – Commercial

The Summer Discount Plan—Commercial (SDP-C)—is a central air conditioning (CAC) direct load control program for commercial customers. SCE began to operate SDP-C as a price-responsive program in 2013. During high system peak hours or emergency conditions, a signal is sent to control devices that limit the operation of the CAC unit. Participants can elect the level of load control—the cycling strategy. SDP-C has three plan options. The Maximum Comfort plan allows SCE to control CAC units up to nine minutes of every half hour, up to six hours a day. The Good Value plan offers CAC control up to 15 minutes of every half hour, up to 6 hours a day. The Maximum Savings plan offers complete CAC curtailment for up to six hours a day. The program is available year-round, can be called for up to six hours per day, and can be dispatched up to 180 hours per year, per participant. The load impacts and enrollment forecasts in this report are summarized across all options of the program for commercial customers. SDP-C was integrated into the CAISO wholesale market in 2015.

2.2.2 Summer Discount Plan – Residential

The Summer Discount Plan—Residential (SDP-R) program—is a CAC direct load control program for residential customers. SCE began to operate SDP-R as a price-responsive program in 2012. During high system peak hours or emergency conditions, a signal is sent to control devices that limit the operation of the CAC unit. The program is available year-round and for all hours of the day, but can only be called up to 6 hours per day and up to 180 hours a year for each participant. As with the SDP-C program, participants choose a cycling strategy. The Maximum Comfort plan offers CAC control up to 15 minutes of every half hour, up to 6 hours a day. The Maximum Savings plan offers complete CAC curtailment up to six hours a day. Both residential plans have an override option. In exchange for receiving a lower incentive, customers can press a button on the load control device, which allows the customer to override up to five event days per calendar year. For customers who have an outdoor CAC and no programmable communicating thermostat (PCT), the override option is only available if their CAC is located on the ground. The load impacts and enrollment forecasts in this report are summarized across all options of the program for residential customers. SDP-R was integrated into the CAISO wholesale market in 2015.

2.2.3 Critical Peak Pricing

Critical Peak Pricing (CPP) is a dynamic pricing program for both residential and nonresidential customers on a time-of-use rate. In 2010, SCE's large customers with demands over 200 kW were defaulted onto CPP. In 2016, mostly large customers with peak demands exceeding 200 kW received service under CPP except for some voluntary small and medium business customers. SCE will default small and medium commercial customers with demands below 200 kW, in addition to large pumping and agricultural customers, to CPP in 2018. Residential customers may opt-in to CPP. Under this rate option, higher prices on critical peak days are offset by a reduction in off-peak prices or demand charges. CPP events occur on nonholiday weekdays between 2 to 6 PM. There are 12 CPP events each calendar year.

2.2.4 Demand Bidding Program

The Demand Bidding Program (DBP) is a voluntary demand reduction program that provides enrolled customers with the opportunity to receive bill credits for load reductions on event days. The program is designed to allow commercial and industrial facilities, of any size, to provide load reduction without firm commitments or participant risk. Because a firm commitment is not required, participants can decide whether or not to bid in load reduction on an event-by-event basis and even if they bid, there is no penalty for not providing the committed reduction. As such, the mix of event participants (versus enrolled participants) and magnitude of load reduction varies from event to event. DBP will be retired at the end of 2017.

2.3 Demand Response Aggregator Managed Programs

Aggregator managed programs are also price-responsive demand response (DR) resources, but they are given a separate category because customers typically, participate in these DR programs through a third party DR aggregator. In aggregator-managed programs, DR aggregators contract with commercial and industrial customers and deliver the aggregated load reduction to the utility. Each DR aggregator forms a portfolio of individual customer accounts and nominates specific accounts for either an existing demand response program such as the Capacity Bidding Program (CBP) or for meeting contractual load reduction obligations. The DR aggregator assumes responsibility for managing relationships with individual customers, arranging for load reductions on event days, receiving incentive payments, and paying penalties (if warranted) to the utility. Customers receive their incentives directly from the DR aggregator. SCE currently has two aggregator-managed programs: CBP and the Aggregator-managed Portfolio (AMP) program.

2.3.1 Capacity Bidding Program

CBP is an aggregator-managed DR program offered by all three IOUs. CBP provides aggregators with monthly capacity payments, paid on a per kW basis, based on the aggregator’s load reduction commitments for each month, plus additional energy payments, paid on a per kWh basis, based on actual electricity demand reductions during events. Each month, aggregators may adjust their nominated load reduction and the mix of customers that provide load reduction for the different event options (e.g., day-ahead or day-of notifications, and event durations of either one-to-four hours, two-to-six hours, or four-to-eight hours). CBP events may be called on nonholiday weekdays, between the hours of 11 AM and 7 PM. CBP day-ahead (CBP-DA) and day-of (CBP-DO) resources are summarized separately in this report. SCE integrated most of its CBP portfolio into the CAISO wholesale energy market beginning June 18, 2015.

2.3.2 Aggregator Managed Portfolio Program

AMP is very similar to the CBP program but is not a statewide program. The primary difference between AMP and CBP is that AMP consists of CPUC-approved bilateral contracts, also known as demand response power purchase agreements, which are individually negotiated and span a specified period of time. Like CBP, AMP aggregators contract with commercial and industrial customers to act on their behalf with respect to all aspects of the program, including receiving notices from the utility, arranging for load reductions on event days, receiving incentive payments, and paying penalties to the utility (if warranted). Each AMP aggregator forms a portfolio of individual customer accounts so that their aggregated load meets or exceeds the DR contract capacity commitment and penalty risk is mitigated. SCE integrated most of its AMP portfolio into the CAISO wholesale energy market by July 2015.

2.4 SmartConnect®-enabled Programs

This report also provides ex post and ex ante load impact estimates for one program in the SmartConnect®-enabled category, which is a segment of demand response programs tied to SCE's rollout of smart meters.

Save Power Day (SPD) is a peak time rebate (PTR) program for bundled residential customers. In 2012 and 2013, SCE residential customers, regardless of whether or not they had opted-in for alert notification, were eligible to receive SPD bill credits. In 2014, SCE began to provide bill credits only to those accounts that opted-in for alert notifications. The Save Power Day program is a voluntary, behavior-based demand response program open to bundled-only SCE residential customers with SmartConnect® meters. The program has three types of customers: opt-in PTR, third party managed PTR+PCT (programmable communicating thermostat), and PTR+IHD (in-home display). Opt-in PTR customers voluntarily enroll to receive event day notifications by phone, text message, or e-mail. PTR+PCT customers have programmable communicating thermostats, which controls HVAC load, that can be controlled by a third party on event days. PTR+IHD customers received in-home displays with similar capabilities as the PCT. SPD provides bill credits to customers based on their specific load reduction on event days when high energy prices are anticipated, and both PTR+IHD and PTR+PCT customers are eligible to earn additional bill credits for utilizing enabling technology. SPD events occur on nonholiday weekdays between 2 to 6 PM.

2.5 Nonevent Based Programs

Nonevent based programs are not dispatchable, but provide load reduction or load shifting on a daily basis. These DR programs provide explicit incentives or time-varying pricing to customers that shift or reduce loads during peak periods.

2.5.1 Real Time Pricing

Real-time pricing (RTP) is a dynamic pricing tariff that charges participants for the electricity they consume based on hourly prices that vary according to day type and temperature. It attempts to incorporate time-varying components of energy costs and generation capacity costs. The RTP tariff consists of nine hourly pricing profiles that vary by season, day type, and daily maximum temperature as measured by the Los Angeles Civic Center weather station. The tariff is available to commercial and agricultural customers. Because the rate schedules are linked to variation in weather, participants experience higher prices on hotter days and a greater number of high-price days during extreme weather years than in normal weather years.

2.5.2 Permanent Load Shifting

The Permanent Load Shifting (PLS) program provides a one-time incentive payment ($875/kW shifted) to customers who install qualifying PLS-Thermal Energy Storage (TES) technology on typical central air conditioning units or process cooling equipment. Incentives are determined based on the designed load shift capability of the system and the project must undergo a feasibility study prepared by a licensed engineer. The load shift is typically accomplished through shifting of daytime chiller load to overnight hours. All electric customers on time-of-use electricity rates are eligible for the program, including residential, commercial, industrial, agricultural, direct access, and Community Choice Aggregation customers. To qualify for the PLS program incentive payment, customers must go through a program application, approval, and verification process. The total incentive amount is determined using a customer’s peak load shift on their maximum cooling demand day (based on on-peak hours). The incentive payments are intended to offset a portion of the cost of installation, thereby making the system more attractive financially. Customers are required to shift load by running the TES system on weekdays during summer months, but program participants are also encouraged to shift load during nonsummer months to maximize their energy bill savings.

2.6 Program Enrollment

Table 2-1 summarizes the SCE DR enrollment forecasts for 2017 through 2027 reported at the portfolio level. Of the five program types, the largest enrollment growth is expected in the SmartConnect-enabled category. SPD with Tech is expected to grow from about 25,000 participants in 2017 to about 130,000 participants in 2027. Overall enrollment in the emergency, price responsive, and aggregator-managed program categories is expected to decline, and enrollment in nonevent based programs is forecast to increase slightly.

Within the emergency category, BIP-30, BIP-15, and AP-I are all expected to shrink by about 10% over the course of the forecast horizon. Within the price-responsive program category, CPP enrollment is expected to grow from about 3,400 participants in 2017 to over 103,000 participants in 2027 due to the default pricing option’s expansion to medium and small customers. Enrollments in the CAC load control programs, SDP-C and SDP-R are expected to decline significantly, by approximately 60% and 40%, respectively, as SCE is planning to implement a new direct load control program. These declining SDP enrollments are counteracted in part by CPP Small and CPP Medium, amounting to a reduction of about 11,000 price-responsive program participants by 2027. Overall, enrollment in SCE DR programs is expected to grow by 28% from about 303,000 participants in 2017 to about 395,000 in 2027.

Table 2-1: SCE DR Portfolio Projected Enrollments for 2017–2027 by Program (Values Reflect Expected Enrollment in August)

Program Type	Program	Forecast Year										
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Emergency	BIP 15-minute	58	57	56	55	54	53	53	53	53	53	53
	BIP 30-minute	522	512	501	491	481	472	472	472	472	472	472
	AP-I	1,177	1,159	1,139	1,121	1,103	1,085	1,085	1,085	1,085	1,085	1,085
Price-responsive	SDP-C	10,503	9,747	9,014	8,307	7,646	7,029	6,452	5,913	5,408	4,937	4,497
	SDP-R	259,776	246,682	234,636	223,108	212,076	201,519	191,417	181,749	172,497	163,643	155,171
	CPP-Large	2,326	2,333	2,340	2,347	2,354	2,361	2,368	2,375	2,382	2,389	2,396
	CPP - Medium	508	508	35,306	35,306	14,430	14,432	14,434	14,435	14,437	14,438	14,440
	CPP - Small	522	522	215,730	215,730	86,609	86,610	86,612	86,613	86,615	86,617	86,618
	DBP	629	0	0	0	0	0	0	0	0	0	0
Demand Response Aggregator-managed	CBP-DA	30	90	90	90	90	90	90	90	90	90	90
	CBP-DO	814	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250
	AMP	1,276	0	0	0	0	0	0	0	0	0	0
SmartConnect®-enabled	SPD with Tech.	24,984	39,167	49,167	59,167	69,167	79,167	89,167	99,167	109,167	119,167	129,167
Nonevent Based	PLS	5	6	8	9	10	11	11	12	12	12	12
	RTP	150	150	150	150	150	150	150	150	150	150	150
Portfolio Total		**303,281**	**302,184**	**549,387**	**547,132**	**395,421**	**394,232**	**393,563**	**393,366**	**393,619**	**394,305**	**395,403**

3 Methodology

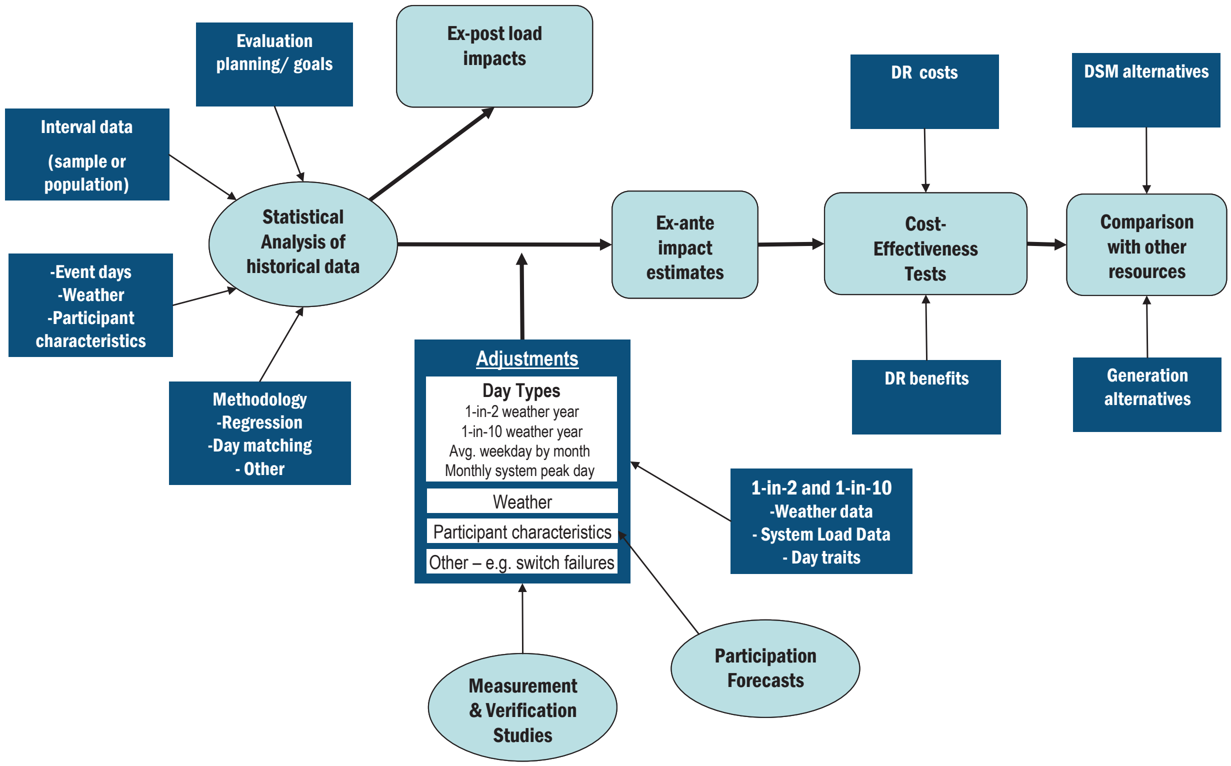
The 2016 evaluations address two main questions for DR programs: what demand reductions were delivered when resources were dispatched in 2016; and, what is the load reduction capability of each DR program?

Ex post impacts reflect the demand reductions attained during actual events, but do not necessarily reflect the load reduction capability of the DR program. Historical ex post results are tied to specific conditions that occurred for that given event, including weather conditions, the number of participants who were dispatched, the mix of customers, and other factors such as switch failure rates. Several programs are dispatched strategically to address congestion in specific zones, test load response capabilities, or for economic reasons. Due to the absence of extreme weather or system emergencies in 2016, emergency resources such as BIP were only dispatched to test load reduction capabilities. In addition, the timing and duration of event dispatch varied across event days for many programs. As a result, the impacts for individual event days are not necessarily representative of the full program capability.

Ex ante impacts reflect the load reduction capability of a DR program for each month under a weather conditions associated with standard 1-in-2 and 1-in-10 system peaking conditions. They reflect the reduction that can be attained if all enrolled participants are dispatched under the weather conditions that drive system planning. Whenever possible, ex ante load impacts are grounded in analysis of historical load impact performance. These estimates are used in assessing alternatives for meeting peak demand, cost-effectiveness comparisons, and long-term planning.

Figure 3-1 shows the connection between ex post load impacts, ex ante impacts, cost-effectiveness analysis, and resource planning. Analysis of historical program data is employed to produce ex ante load impact estimates that are subsequently used for resource adequacy, cost-effectiveness assessment and, by connection, resource planning.

Figure 3-1: Summary of Ex Post and Ex Ante Analysis Process and Connections



3.1 Selection of Ex Ante Weather Conditions

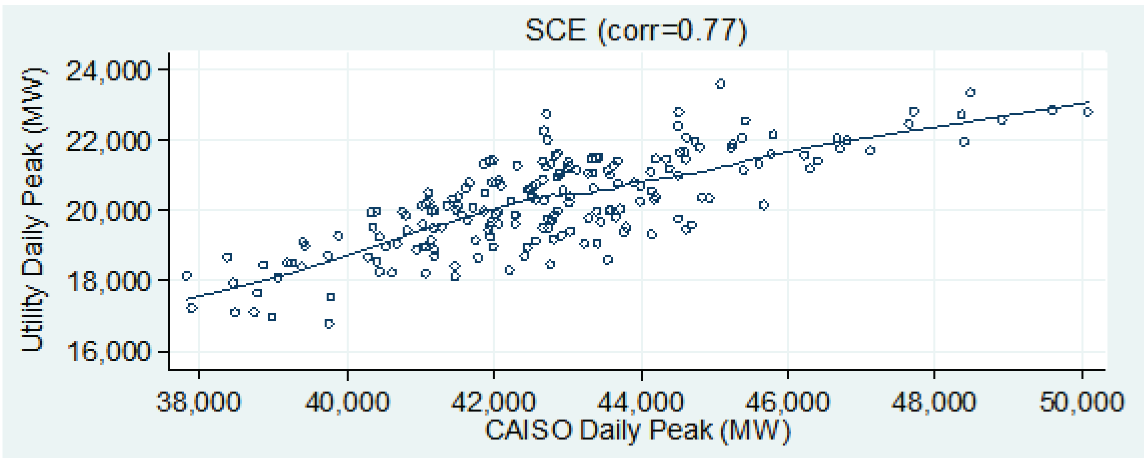
The Protocols require that ex ante load impacts be estimated assuming weather conditions associated with both normal and extreme utility operating conditions. Normal conditions are defined as those that would be expected to occur once every 2 years (1-in-2 conditions) and extreme conditions are those that would be expected to occur once every 10 years (1-in-10 conditions). From 2008 to 2013, SCE has based ex ante weather on system operating conditions specific to their own system. However, ex ante weather conditions could alternatively reflect 1-in-2 and 1-in-10 year operating conditions for the California Independent System Operator (CAISO) rather than the operating conditions for SCE. While the Protocols are silent on this issue, a letter from the CPUC Energy Division to the three California electric investor-owned utilities dated October 21, 2014 directed them to provide impact estimates under two sets of operating conditions starting with the April 1, 2015 filings: one reflecting operating conditions for each utility and one reflecting operating conditions for the CAISO system.

In order to meet this new requirement, the utilities developed ex ante weather conditions based on the peaking conditions for each utility and for the CAISO system. The previous ex ante weather conditions for each utility were developed in 2009 and were updated along with the development of the new CAISO-based conditions. Both sets of estimates used a common methodology, which was documented in a report delivered to the utilities.[3]

[3] See *Statewide Demand Response Ex Ante Weather Conditions*. Nexant, Inc. January 30, 2015.

The extent to which utility-specific ex ante weather conditions differ from CAISO ex ante weather conditions is related to the correlation between individual utility and CAISO peak loads. Figure 3-2 shows the correlations between SCE peaks and CAISO system wide daily peaks. Because the focus is on peaking conditions, the graph includes the 25 days with the highest CAISO loads in each year from 2006–2013 (25 days per year for 8 years, providing 200 observations per utility).

Figure 3-2: Relationship between CAISO and SCE Peak Loads CAISO Top 25 Peak Days per Year (2006–2013)



SCE peak loads are more closely related to CAISO peak loads than are PG&E or SDG&E peak loads. Part of the explanation is simply that SCE constitutes a larger share of CAISO load than do the other two utilities, and therefore SCE has more influence on the overall CAISO loads. However, there are additional reasons for the differences. PG&E's northern California service territory experiences different weather systems and is more likely to peak earlier in the year than the overall CAISO system. SDG&E weekday loads and weather patterns are also unique. A larger share of SDG&E's load is residential and less of it is industrial. Temperatures peak earlier in the day than load does at SDG&E and the diurnal swing between overnight and peak temperatures is smaller.

While IOU and CAISO loads do not peak at the same time all the time, the relationship between CAISO loads and utility peaking conditions has been weakest when CAISO loads have been below 45,000 MW. For example, CAISO loads often reach 43,000 MW when Southern California loads are extreme but Northern California loads are moderate (or vice-versa). However, whenever CAISO loads have exceeded 45,000 MW, loads typically have been high across all three IOUs.

Table 3-1 shows the values for each weather scenario, weather year, and month for a variable equal to the average temperature from midnight to 5 PM (referred to as *mean17*) for each day type. For the typical event day, the CAISO weather is hotter on average than the utility-specific weather for SCE for 1-in-2 and is nearly equal under 1-in-10 year weather conditions.

Table 3-1: SCE Sales-weighted Ex Ante Weather Values (mean17) on Monthly Peak Days

Month	1-in-2		1-in-10	
	Utility-specific	CAISO	Utility-specific	CAISO
5	69.4	68	77.7	76.3
6	71.8	72.7	76.3	76.9
7	75.5	78.8	79.8	79.1
8	79.2	78.4	81.5	80.8
9	75.5	77.9	82	82.5
10	74.2	70.6	76.7	76.9
Avg. (May-Oct)	74.3	74.4	79	78.7

3.2 Overview of Evaluation Methods

The methods used to estimate ex post and ex ante load impacts for each of the DR programs in the SCE portfolio are conceptually similar. Nearly all of the 2016 evaluations relied on, or partially relied on, regression analysis to estimate a model reflecting the relationship between customer whole-premise or end-use load and key determinants of the variation in energy use over time, such as weather and time-of-day, day-of-week, and seasonal patterns that reflect the normal pattern of business or household operations. In some cases, a matched control group was used to estimate reference load for the purpose of deriving load impacts. For those, load is not modeled as a function of weather and time-of-day for the purpose of determining reference load; rather, reference load for the treatment group is simply the observed load of the control group, minus the small difference between treatment and control loads observed on nonevent days. Nevertheless, reference load models are still required even in this setting for the purpose of ex ante load impact estimation. The exception in 2016 is the PLS evaluation, which had a single installed project at the time of the evaluation. The PLS evaluation primarily relies on building simulation modeling to develop ex ante load impacts given further assumptions about the timing, geographic location, project size, and budget for the program across the ex ante forecast horizon.

Regression models are based on historical hourly or sub-hourly electricity use data for customers who have participated in the DR programs. Each model or set of models is used to estimate the reference load for an average customer enrolled in a program, which represents what customers would be expected to use in the absence of an event on days in which program events either were called (for ex post impact estimation) or have a high probability of being called (for ex ante impact estimation). For RTP, the methods were slightly different. RTP reference loads represent what the average customer would use on a specific day if they faced the otherwise applicable tariff, TOU-8, rather than the RTP tariff.

In most instances, ex post load impacts were estimated by comparing the reference level energy use in each hour with the estimated load with DR in the hour on each event day. For ex ante estimation, predicted energy use in each hour was estimated under the assumption that an event occurred and also under the assumption that it did not occur, while everything else (e.g., weather, day-of-week effects) was held constant at values representative of a typical event day or monthly system peak day.

At a more technical level, three general approaches were used to estimate the regression models:

- **Individual Customer Time Series Regressions:** This method works well for event-based programs with numerous events and for programs with substantial variation in the drivers of load response or load shifting. This approach is also useful for programs with substantial differences in the magnitude and load patterns of customers, which is more typical among large customers. The coefficients vary at the customer level. The regressions do not necessarily explain individual customer behavior perfectly, but on aggregate they explain most of the program level variation in loads. Importantly, individual customer regressions can be employed to describe the distribution of customer load reductions as well as the distribution of percent load reductions. They can also be used to describe impacts for segments of the participant population. The key limitation to individual customer regressions is that they have no control group, and therefore they have limited ability to account for non-observable variations.
- **Aggregate Time Series Regressions:** Similar to the individual customer regression approach, but rather than estimating reference loads and load impacts for individual customers, estimates are made for groups of customers taken in aggregate.
- **Panel Regressions:** This method is particularly suitable when control groups are available, or sample sizes are sufficient for the territory, but inadequate for smaller segments such as local capacity areas. A key strength of panel regressions is the ability to control for certain omitted or unobservable variables.[4] While panel regressions can increase the accuracy of impact estimates for the average customer, they cannot be employed to describe the distribution of impacts among the participant population. Importantly, panel regressions cannot control for customer characteristics that interact with occupancy and or weather unless those variables are explicitly included.

The regression models used to predict the reference load were developed with the primary goal of accurately predicting average customer load given the time of day, day of week, temperature, and location of each customer and predicting load reductions under different temperature conditions. The focus was on the accuracy of the prediction and the validity of load impact

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[4] Panel regressions can account for omitted variables that are unique to customers and relatively time invariant over the analysis time frame (fixed effects) such as household income. Panel regressions can also account for omitted variables that are common across the participant population but unique to specific time periods (time effects). They cannot, however, account for omitted variables that vary both by participant and by time period or for household characteristics (e.g., central air conditioning) that interact with variables that vary over time, such as weather and occupancy.

estimates. The regression equations used to model load patterns and estimate load impacts for each program are detailed in Appendix B.

3.3 Program-specific Analysis Methods

Table 3-2 summarizes the analysis methodology for each program. It describes the general approach used for load impact estimation and details key assumptions required in the analysis. The specific methodology chosen for each program was based on the available data, event dispatch patterns, and the strengths and weakness of each available analysis approach.

Table 3-2: Summary of Analysis Methodologies by Program

Program	Method	Evaluation Description	Key Assumptions
Base Interruptible Program (BIP-15 and BIP-30)	Regression models - individual customer	Ex post hourly load impacts were estimated using regression equations applied to customer-level hourly load data. Ex ante impacts were estimated as the reference load under 1-in-2 and 1-in-10 system peak conditions minus the firm service level, with adjustments based on historical over- or under-performance.	▪ Customers will continue to perform relative to their FSL in the future as they have in the past ▪ Enrollment growth is expected to slightly decline until 2022 and hold steady throughout the remainder of the forecast horizon.
Agricultural Pumping Interruptible Program (AP-I)	Regression models - individual customer	Agricultural pump loads were modeled as a function of time of day, day of week, temperature, and other factors. Estimates of switch activation success rates were developed based on the 10/19/16 event and applied to reference loads in the ex ante analysis.	▪ Pump loads are fully shut down when switch activation is successful. ▪ Switch activation success rates are assumed to improve through 2020 due to an effort to identify and fix communication and switch failures. ▪ A small decrease in enrollment is expected through 2022, and enrollment will hold steady thereafter.
Summer Discount Plan - Commercial (SDP-C)	Statistically-matched control group	Propensity score matching was used to select a control group. A difference-in-differences approach was used by subtracting the difference between treatment and control customers on hot nonevent days from the difference between the groups on event days. A same-day adjustment was also applied to the reference load based on the treatment group's load during the four hours prior to the event.	▪ Ex ante estimates assume that participants' characteristics such as CAC tonnage and SEER rating do not change. ▪ Changes in program enrollment will reflect the current distribution of SDP customers. ▪ Enrollment is expected to decline by about 60% by 2027 as SCE prepares to launch a new direct load control program.

Program	Method	Evaluation Description	Key Assumptions
Summer Discount Plan - Residential (SDP-R)	Statistically-matched control group	Propensity score matching was used to select a control group. A difference-in-differences approach was used by subtracting the difference between treatment and control customers on hot nonevent days from the difference between the groups on event days. A same-day adjustment was also applied to the reference load based on the treatment group's load during the four hours prior to the event.	▪ Changes in program enrollment will reflect the current distribution of SDP customers. ▪ Ex ante estimates assume that participants' characteristics such as CAC tonnage and SEER rating do not change. ▪ Enrollment is expected to decline by about 40% between 2017 and 2027 as SCE prepares to launch a new direct load control program.
Critical Peak Pricing (CPP)	Statistically-matched control group and individual customer regressions	Ex post load impacts are estimated using load data for CPP customers and a statistically matched control group of non-CPP customers; individual customer regressions were used for certain customer groups for whom the matched control group approach was not possible. Ex ante load impacts were estimated by modeling reference load and percentage load impacts a function of weather for persistent CPP customers (customers who participated in CPP in both 2015 and 2016).	▪ Future load impacts will have a similar relationship to weather as observed 2016. ▪ CPP-L participation will grow slowly; CPP-M and CPP-S will grow many-fold in 2020 , resulting in 100,000 more customers enrolled on the rate by 2027.
Demand Bidding Program (DBP)	Regression models - individual customer	Ex post hourly load impacts were estimated using regression equations applied to customer-level hourly load data. Ex ante load impacts were estimated using percentage load impacts directly calculated from 2014-2016 ex post results and applied to 1-in-2 and 1-in-10 weather reference loads.	▪ Future bidding behavior will be similar to current bidding behavior; future load impacts for each customer will be similar to historical performance in 2014, 2015, and 2016. ▪ The program will be terminated at the end of 2017.

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Program	Method	Evaluation Description	Key Assumptions
Capacity Bidding Program (CBP-DA and CPB-DO)	Regression models - individual customer	Ex post hourly load impacts were estimated using regression equations applied to customer-level hourly load data. Ex ante load impacts were estimated using percentage load impacts directly calculated from 2016 ex post results (for each customer enrolled in the program at the end of the 2016 cycle) and applied to 1-in-2 and 1-in-10 weather reference loads.	▪ Future load impacts for each customer will be similar to historical performance in 2016. ▪ Customer mix at SCE will be similar to that of the 2016 participants. ▪ CBP-DA enrollment will triple by 2018; CBP-DO will grow by more than 50% in 2018; no growth predicted 2018 to 2027.
Aggregator-managed Portfolios (AMP)	Regression models - individual customer	Ex post hourly load impacts were estimated using regression equations applied to customer-level hourly load data. Ex ante load impacts were estimated using percentage load impacts directly calculated from 2016 ex post results and applied to 1-in-2 and 1-in-10 weather reference loads.	▪ Future load impacts for each customer will be similar to historical performance in 2016. ▪ Customer mix at SCE will be similar to that of the 2016 participants. ▪ Enrollment is expected to drop to 0 in 2018.
Save Power Day (SPD)	Statistically-matched control group	Ex post load impacts are estimated using load data for SPD customers and a statistically matched control group of non-SPD customers; load impacts are calculated using a difference-in-differences approach. Ex ante load impacts are estimated by modeling 2016 load impacts as a function of weather, and using the estimated model to predict load impacts for ex ante weather conditions.	▪ SPD notification program will terminate and only the direct load control program will remain, effective at the end of 2017. ▪ SPD participants currently enrolled in the PCT program are representative of future participants on the program. ▪ SPD participants with enabling technology will dramatically increase to about 130,000 customers in 2027.

Program	Method	Evaluation Description	Key Assumptions
Real-time Pricing (RTP)	Regression models - individual customer	Customer load was modeled as a function of time of day, day of week, weather (for some customers) and hourly price schedules using 2016 hourly data. The impacts were estimated as the difference between customer loads under RTP and estimated hourly loads under the otherwise applicable tariff prices based on individual customer price response.	▪ Customers will continue to respond to prices as they have in the past. ▪ The three large customers who have been on the program for three or more years are not projected to leave RTP during the forecast horizon; customers who enroll will be similar to the average customer. ▪ RTP enrollment is expected to be constant over the forecast horizon. ▪ RTP will be available to TOU-8 customers; future RTP and TOU-8 rates will be similar to present rates.
Permanent Load Shifting (PLS)	Individual customer regression and building simulation modeling combined with assumptions regarding unidentified projects	Ex ante impacts were forecast for three different types of projects—operational, identified (those for which customers have completed an application) and unidentified (applications that are expected to be submitted by the end of 2022). Impacts for the operational customer were based on their individual regression model. Load impacts for identified and unidentified projects were developed using building simulation models. Impacts for identified projects were allocated to LCAs based on the expected project installation date. The allocation of impacts for unidentified projects were estimated based on key assumptions from the PLS program manager and M&E staff.	▪ The number of unidentified installations assumes that 60% of remaining incentive budget will be spent; unidentified projects are assumed to come online through 2024. ▪ Expected size of unidentified projects is 675 kW. ▪ It is assumed that 25% of projects that reach the application stage will drop out of the program prior to project installation. ▪ PLS load impacts are projected to degrade by 2.5% per annum after five years in service due to expected losses in system efficiency. ▪ Unidentified projects are distributed by LCA, proportional to the distribution of the large C&I population across LCAs.

4 Ex Post Load Impact Estimates

This section summarizes the load impacts in 2016 for event-based programs. Ex post load impacts are based on modeling electricity use patterns and load impacts over a historical period. All evaluations involve electricity usage data from program participants; for some programs, usage data from control customers who do not participate in the program is also used. Control data is used to estimate reference load for the hours prior to, during, and after DR events. In general, ex post load impacts estimate what happened based on the conditions that were in effect during the time of each event. While historical load patterns and impacts are critical for understanding the magnitude of load reduction resources, they have limitations. Because historical performance is tied to past conditions such as weather, price levels, and dispatch strategy (e.g., localized dispatches), ex post load impacts may not reflect the full option value of a DR resource. For example, a test event for a highly weather-sensitive program such as SDP-C may yield lower impacts than what the program can provide because future events might occur at hotter temperatures when air conditioning loads are higher. Likewise, resources such as CBP or AMP may be dispatched partially—one product line is called—in which case ex post events may not necessarily reflect the program load reduction capability.

4.1 Summary of 2016 Events

In 2016, SCE DR resources were dispatched based on program rules and need. The event days and event hours differed across programs and, sometimes, within programs. Table 4-1 summarizes the events called in 2016 by date and program. RTP and PLS no not appear in the table because they are not event-based programs. SDP, CBP, and SPD were dispatched most frequently of the event-based programs.

As noted earlier, several programs are dispatched strategically to address congestion in specific zones, to test load response capabilities, or for economic reasons. For CBP and AMP, different combinations of program products and/or aggregators (if applicable) were dispatched for each individual event in 2016. As a result, the impacts for individual event days are not necessarily representative of the resources available should SCE solicit demand reductions from all aggregator resources at once.

Table 4-1: Summary of 2016 SCE Demand Response Events by Date and Program

Date	AMP	AP-I	BIP	CBP-DO	CBP-DA	DBP	CPP	SDP-C	SDP-R	SPD
2/29/2016									6:00PM - 7:00PM	
10/19/2016		01:30PM - 4:30PM								
4/1/2016				06:00PM - 07:00PM						
4/6/2016				06:00PM - 07:00PM					7:00PM - 8:00PM	
5/2/2016					06:00PM- 07:00PM					
5/12/2016				06:00PM - 07:00PM	06:00PM - 07:00PM				6:00PM - 8:00PM / 7:00PM - 8:00PM	
5/26/2016	1:00 PM - 3:00 PM									
6/3/2016				03:00PM - 07:00PM / 04:00PM - 07:00PM / 05:00PM - 07:00PM / 06:00PM - 07:00PM	03:00PM- 07:00PM / 04:00PM - 07:00PM / 05:00PM - 07:00PM / 06:00PM - 07:00PM				7:00PM - 8:00PM	
6/8/2016				06:00PM - 07:00PM	06:00PM - 07:00PM					

Date	AMP	AP-I	BIP	CBP-DO	CBP-DA	DBP	CPP	SDP-C	SDP-R	SPD
6/20/2016	3:00 PM - 6:00 PM			03:00PM - 07:00PM	03:00PM - 07:00PM	12:00PM - 8:00PM	2:00PM - 6:00PM	4:00PM - 5:00PM / 4:00PM - 6:00PM / 4:00PM - 8:00PM	4:00PM - 8:00PM	2:00PM - 6:00PM
6/21/2016				03:00PM - 07:00PM / 04:00PM - 07:00PM	03:00PM - 07:00PM / 04:00PM - 07:00PM	12:00PM - 8:00PM	2:00PM - 6:00PM	4:00PM - 5:00PM	4:00PM - 5:00PM	2:00PM - 6:00PM
6/22/2016				03:00PM - 04:00PM / 03:00PM - 05:00PM	03:00PM - 04:00PM / 03:00PM - 05:00PM					
6/27/2016				03:00PM - 07:00PM / 04:00PM - 07:00PM	03:00PM - 07:00PM	12:00PM - 8:00PM	2:00PM - 6:00PM	4:00PM - 5:00PM / 6:00PM - 8:00PM / 4:00PM - 8:00PM	4:00PM - 5:00PM / 4:00PM - 8:00PM / 6:00PM - 8:00PM	2:00PM - 6:00PM
6/28/2016				05:00PM - 06:00PM	03:00PM - 07:00PM / 04:00PM - 07:00PM	12:00PM - 8:00PM	2:00PM - 6:00PM			2:00PM - 6:00PM
6/29/2016										2:00PM - 6:00PM
6/30/2016	2:00 PM - 4:00 PM			05:00PM - 06:00PM	05:00PM - 06:00PM					
7/12/2016				02:00PM - 03:00PM	02:00PM - 03:00PM					

Date	AMP	AP-I	BIP	CBP-DO	CBP-DA	DBP	CPP	SDP-C	SDP-R	SPD
7/13/2016				01:00PM - 03:00PM / 02:00PM - 03:00PM	01:00PM - 03:00PM / 02:00PM - 03:00PM					
7/14/2016				04:00PM - 07:00PM / 06:00PM - 07:00PM	04:00PM - 07:00PM / 06:00PM - 07:00PM					
7/20/2016				04:00PM - 07:00PM	04:00PM - 07:00PM			7:00PM - 8:00PM		
7/21/2016				03:00PM - 07:00PM	03:00PM - 07:00PM		2:00PM - 6:00PM	4:00PM - 5:00PM / 6:00PM - 8:00PM / 4:00PM - 8:00PM	4:00PM - 5:00PM / 4:00PM - 8:00PM / 6:00PM - 8:00PM	
7/22/2016				03:00PM - 07:00PM / 04:00PM - 07:00PM	03:00PM - 07:00PM / 04:00PM - 07:00PM	12:00PM - 8:00PM	2:00PM - 6:00PM	4:00PM - 5:00PM / 6:00PM - 8:00PM / 4:00PM - 8:00PM / 4:00PM - 7:00PM / 7:00PM - 8:00PM	4:00PM - 5:00PM / 4:00PM - 8:00PM / 7:00PM - 8:00PM	2:00PM - 6:00PM
7/25/2016				03:00PM - 07:00PM / 04:00PM - 07:00PM	03:00PM - 07:00PM / 04:00PM - 07:00PM	12:00PM - 8:00PM	2:00PM - 6:00PM	6:00PM - 8:00PM / 7:00PM - 8:00PM	6:00PM - 8:00PM / 7:00PM - 8:00PM	2:00PM - 6:00PM
7/26/2016				04:00PM - 07:00PM / 06:00PM - 07:00PM	04:00PM - 07:00PM / 06:00PM - 07:00PM	12:00PM - 8:00PM	2:00PM - 6:00PM	6:00PM - 8:00PM / 7:00PM - 8:00PM		2:00PM - 6:00PM

Date	AMP	AP-I	BIP	CBP-DO	CBP-DA	DBP	CPP	SDP-C	SDP-R	SPD
7/27/2016				03:00PM - 07:00PM	03:00PM - 07:00PM	12:00PM - 8:00PM		4:00PM - 8:00PM	4:00PM - 8:00PM / 5:00PM - 8:00PM	2:00PM - 6:00PM
7/28/2016	4:00 PM - 5:00 PM			03:00PM - 07:00PM / 06:00PM - 07:00PM	03:00PM - 07:00PM / 06:00PM - 07:00PM	12:00PM - 8:00PM		5:00PM - 8:00PM / 6:00PM - 7:00PM	6:00PM - 8:00PM / 6:00PM - 7:00PM	2:00PM - 6:00PM
7/29/2016	4:00 PM - 5:00 PM			03:00PM - 07:00PM / 04:00PM - 06:00PM / 04:00PM - 07:00PM	03:00PM - 07:00PM / 04:00PM - 06:00PM / 04:00PM - 07:00PM	12:00PM - 8:00PM				2:00PM - 6:00PM
8/1/2016				06:00PM - 07:00PM	03:00PM - 07:00PM		2:00PM - 6:00PM			
8/2/2016				06:00PM - 07:00PM	06:00PM - 07:00PM					
8/3/2016							2:00PM - 6:00PM			
8/4/2016				06:00PM - 07:00PM	06:00PM - 07:00PM					
8/12/2016				06:00PM - 07:00PM	06:00PM - 07:00PM					
8/15/2016	1:00 PM - 2:00 PM / 3:00 PM - 6:00 PM			02:00PM - 06:00PM / 03:00PM - 07:00PM / 04:00PM - 07:00PM	04:00PM - 07:00PM	12:00PM - 8:00PM	2:00PM - 6:00PM	5:00PM - 8:00PM	6:00PM - 8:00PM	2:00PM - 6:00PM
8/16/2016				04:00PM - 07:00PM	04:00PM - 07:00PM	12:00PM - 8:00PM	2:00PM - 6:00PM	5:00PM - 8:00PM	6:00PM - 8:00PM	2:00PM - 6:00PM

Date	AMP	AP-I	BIP	CBP-DO	CBP-DA	DBP	CPP	SDP-C	SDP-R	SPD
8/17/2016				05:00PM - 07:00PM / 06:00PM - 07:00PM	05:00PM - 07:00PM / 06:00PM - 07:00PM	12:00PM - 8:00PM		3:12PM - 5:40PM	3:10PM - 5:40PM	2:00PM - 6:00PM
8/18/2016				04:00PM - 07:00PM / 05:00PM - 07:00PM	04:00PM - 07:00PM / 05:00PM - 07:00PM			6:00PM - 7:00PM		
8/19/2016				06:00PM - 07:00PM	06:00PM - 07:00PM					
8/30/2016				06:00PM - 07:00PM	06:00PM - 07:00PM					
8/31/2016	5:00 PM - 7:00 PM			04:00PM - 07:00PM	04:00PM - 07:00PM					
9/7/2016				06:00PM - 07:00PM	06:00PM - 07:00PM					
9/26/2016	3:00 PM - 5:00 PM / 3:00 PM - 6:00 PM			04:00PM - 07:00PM	06:00PM - 07:00PM			6:00PM - 8:00PM	6:00PM - 8:00PM	
9/27/2016				05:00PM - 07:00PM	05:00PM - 07:00PM					
9/28/2016				06:00PM - 07:00PM	06:00PM - 07:00PM					
10/6/2016				06:00PM - 07:00PM	06:00PM - 07:00PM			7:00PM - 8:00PM	7:00PM - 8:00PM	
10/7/2016				05:00PM - 07:00PM / 06:00PM - 07:00PM	05:00PM - 07:00PM / 06:00PM - 07:00PM			7:00PM - 8:00PM	7:00PM - 8:00PM	

Date	AMP	AP-I	BIP	CBP-DO	CBP-DA	DBP	CPP	SDP-C	SDP-R	SPD
10/10/2016				06:00PM - 07:00PM	06:00PM - 07:00PM					
10/17/2016				06:00PM - 07:00PM	06:00PM - 07:00PM					
10/18/2016				06:00PM - 07:00PM	06:00PM - 07:00PM					
10/19/2016		1:30PM - 4:30PM	12:55PM - 4:00PM	05:00PM - 07:00PM / 06:00PM - 07:00PM	05:00PM - 07:00PM / 06:00PM - 07:00PM					
10/20/2016				05:00PM - 07:00PM	05:00PM - 07:00PM					
10/21/2016				05:00PM - 07:00PM / 06:00PM - 07:00PM	05:00PM - 07:00PM / 06:00PM - 07:00PM					
10/24/2016				06:00PM - 07:00PM	06:00PM - 07:00PM					
10/25/2016				06:00PM - 07:00PM	06:00PM - 07:00PM					
10/26/2016				06:00PM - 07:00PM	06:00PM - 07:00PM					
10/27/2016				05:00PM - 07:00PM / 06:00PM - 07:00PM	05:00PM - 07:00PM / 06:00PM - 07:00PM					
10/31/2016	2:00 PM - 4:00 PM				06:00PM - 07:00PM					

Date	AMP	AP-I	BIP	CBP-DO	CBP-DA	DBP	CPP	SDP-C	SDP-R	SPD
11/7/2016				05:00PM - 07:00PM / 06:00PM - 07:00PM						
11/8/2016				04:00PM - 07:00PM / 06:00PM - 07:00PM						
11/9/2016				04:00PM - 07:00PM / 05:00PM - 07:00PM / 06:00PM - 07:00PM						
11/10/2016				04:00PM - 07:00PM / 05:00PM - 06:00PM / 05:00PM - 07:00PM						

Interpreting the average event impact across events can be difficult because multiple factors can vary across event days, including temperature, the normal pattern of energy use, enrollment, the number of customers called, dispatch strategy, and number of event hours. For programs such as large customer DBP and CPP with stable participation, fixed event windows, less weather-sensitive customers, and universal dispatch for all events, the average event impacts can provide meaningful and insightful data about program performance. However, for resources that do not have those characteristics, the average event impacts provide limited insight and can be misleading. In short, ex post load impacts may not reflect the full option value of a DR resource and should be interpreted with caution. In the case of CBP and AMP, not only was a subset of customers called for each event, but the customers called for each event were not necessarily representative of the overall program.

Table 4-2 summarizes the average event impacts across all events for each of SCE's programs that had an event in 2016. A total row at the bottom is not provided because these are different types of programs that were dispatched at different times in 2016, as shown in Table 4-1.

Table 4-2: 2016 Ex Post Load Impacts for the Average Event by Event-based Program

Program	Reference Load (kW)	Load with DR (kW)	Load Impact per Customer (kW)	% Load Impact	Aggregate Impact (MW)	Accounts Called	Number of Events
AP-I	33	4	29	88%	35	1,192	1
BIP 15-minute	3,112	263	2,849	92%	165	58	1
BIP 30-minute	1,175	309	867	74%	461	532	1
SDP-C	17	15	2	10%	6	3,384	30
SDP-R	3	2	1	31%	83	105,236	26
CPP-Large	234	220	14	6%	34	2,545	12
DBP	904	772	132	15%	101	765	13
CBP-DA*	[redacted]						
CBP-DO*							
AMP	239	181	58	24%	92	1,571	7
SPD without Tech.	2	2	0	4%	25	324,681	14
SPD with PCT	2	2	1	34%	2.08	2,682	12

*Redacted to protect confidential customer information

5 Ex Ante Load Impacts

The portfolio ex ante load impact estimates summarize the load reduction that can be expected from all of SCE's DR programs if they are called simultaneously. They are based on a common event window and the weather conditions underlying 1-in-2 and 1-in-10 monthly system peak days. The weather conditions further vary according to whether or not the program is assumed to be called on a SCE monthly system peak day or a CAISO monthly system peak day. The ex ante estimates provide a projection of the resources available under conditions that are linked to the need for investment in additional capacity. The load impact estimates for each program align with the peak period used for resource adequacy planning, 1 to 6 PM in April through October and 4 to 9 PM in November through March.

Portfolio-adjusted load reductions reflect the assignment of load impacts from dually enrolled accounts to a single program in order to avoid double counting impacts. Dual participation is allowed for many of SCE's DR programs. The largest overlaps in the nonresidential programs (which can exceed 30% or even 40% of program enrollment) occur among DBP participants who dually enroll in either BIP or AMP in addition to AMP customers who dually enroll in CBP. There is also significant amount of dual enrollment between the residential programs, SPD and SDP-R; more than 20% of SPD participants dually enroll in SDP-R. The load impacts of customers enrolled in both an emergency program and a price-responsive program are attributed to the emergency response program for portfolio-adjusted reporting.

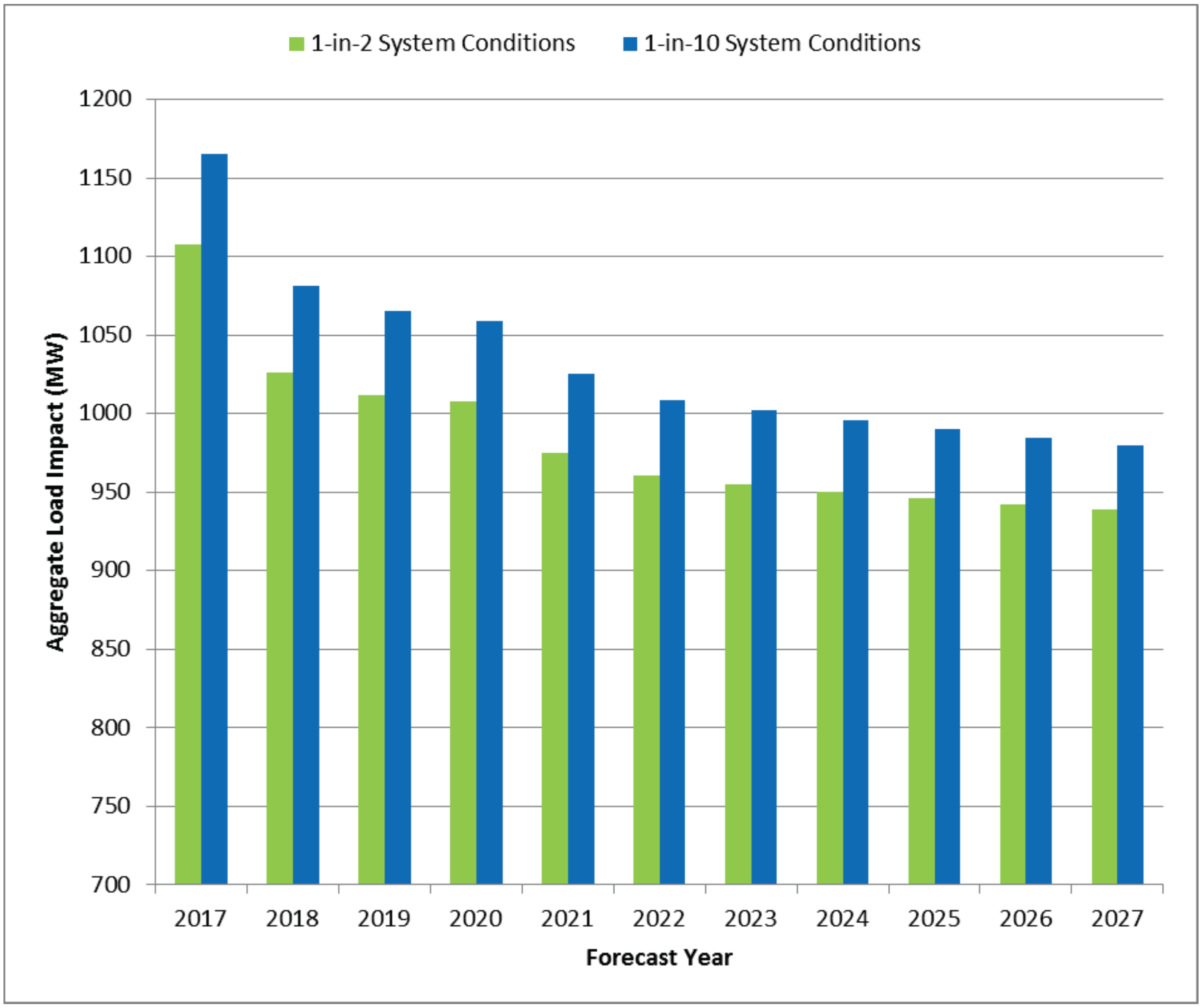
The remainder of this section summarizes the ex ante load impact estimates for SCE's portfolio of DR programs. The discussion focuses on high-level portfolio aggregate impacts by forecast year, month, and program type and assumes SCE-specific monthly peaking conditions. The remainder of the portfolio-adjusted and program-specific estimates that are required to be included in this executive summary by the Protocols can be found in Appendices C through J. Appendices C through F present ex ante load impacts assuming SCE-specific peaking conditions while Appendices G through J present ex ante load impacts assuming CAISO peaking conditions.

5.1 Projected Change in Portfolio Load Impacts from 2017–2027

Figure 5-1 presents the portfolio-adjusted aggregate load impact estimates for the August system peak day under 1-in-2 and 1-in-10 SCE-specific system conditions by forecast year. The estimated aggregate load reduction is highest in 2017 and declines every year through the end of the forecast horizon in 2027. Under 1-in-2 system conditions, SCE's DR portfolio is projected to fall 15%, from 1,104[5] MW in 2017 to 940 MW in 2027. Under 1-in-10 system conditions, SCE's DR portfolio is expected to deliver 1,161* MW for the 1-in-10 August system peak day in 2017, declining 16% to 980 MW by 2027.

[5] 2017 load impacts for Permanent Load Shifting (PLS) are not included in this sum, since they are confidential.

Figure 5-1: Portfolio Aggregate Ex Ante Load Impact Estimates (MW) for the August System Peak Day by 1-in-2 and 1-in-10 SCE-specific System Conditions and Year

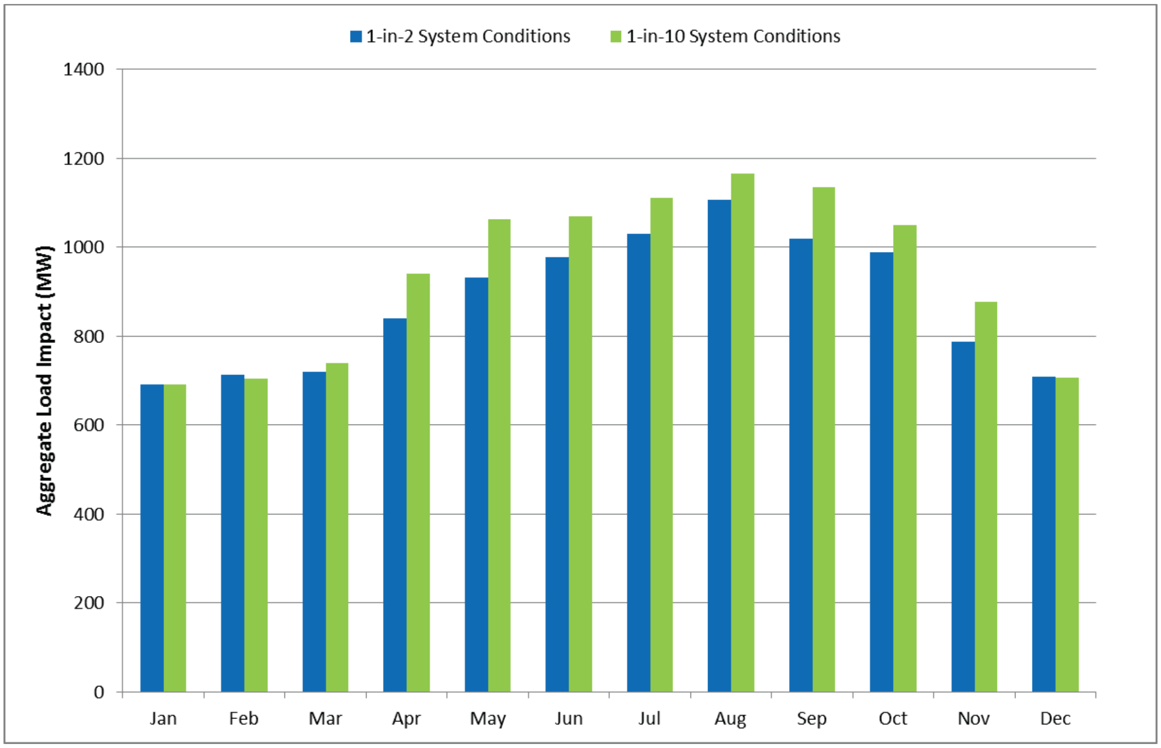


5.2 2017 Portfolio Aggregate Load Impacts by Month

Figure 5-2 shows how the 2017 portfolio load impacts vary by month under 1-in-2 and 1-in-10 SCE-specific system conditions. In 2017, SCE's DR portfolio is projected to be capable of delivering up to 1,161* MW of load reduction during the August monthly system peak day under 1-in-10 system conditions. The July and September load impacts under 1-in-10 system conditions are similar, at 1,107* and 1,131* MW, respectively. The portfolio load impacts during non-summer months are substantially lower, largely due to the fact that SDP-C and SDP-R only provide load impacts during the summer months when cooling loads are available for curtailment.

*2017 load impacts for Permanent Load Shifting (PLS) are not included in this sum, since they are confidential.

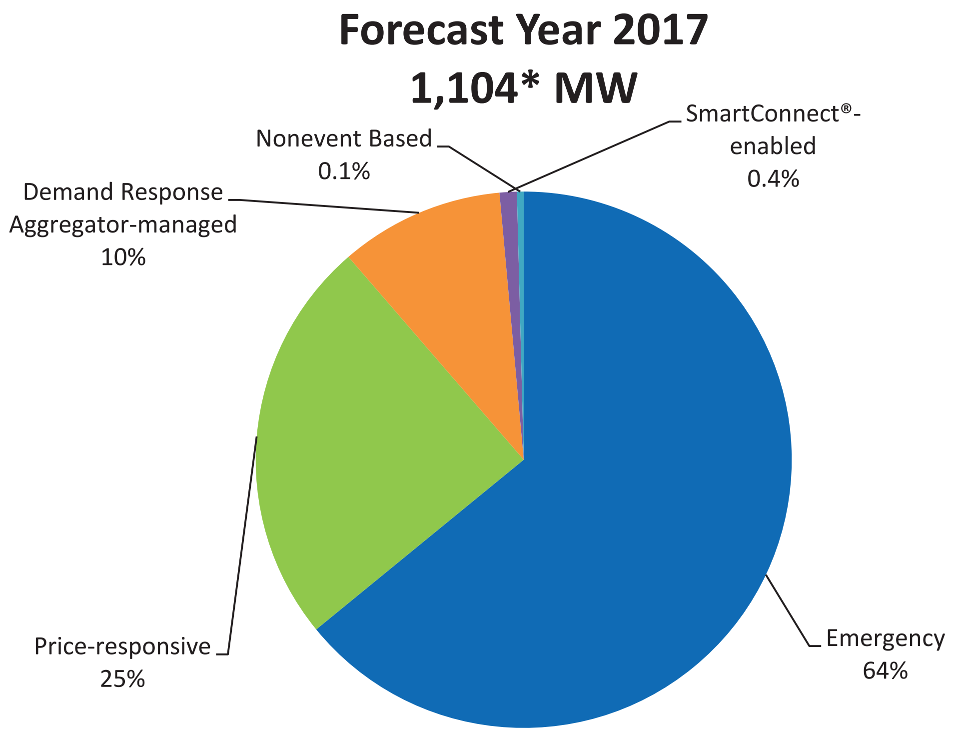
Figure 5-2: 2017 Portfolio Aggregate Ex Ante Load Impact Estimates (MW) by 1-in-2 and 1-in-10 SCE-specific System Conditions and Monthly System Peak Day



5.3 Portfolio Load Impacts by Program Type

SCE has moved in recent years towards a more balanced DR portfolio by program type with fewer emergency response resources. Figure 5-3 shows the distribution of portfolio aggregate load impacts by program type in 2017. Load impacts from emergency response programs are forecast to comprise 64% of SCE's DR portfolio during this period. Most of the remaining load impacts are forecast to come from aggregator-managed programs (10%) and price-responsive programs (25%). Figure 5-4 shows the distribution of portfolio aggregate load impacts by program type for the year 2027. A greater percentage of load impacts are projected to come from SmartConnect-enabled and emergency programs by 2027, with a smaller share of load impacts expected to be delivered by aggregator-managed and price-responsive programs.

Figure 5-3: Distribution of Portfolio Aggregate Load Impacts by Program Type 2017 August System Peak Day under 1-in-2 SCE-specific System Conditions



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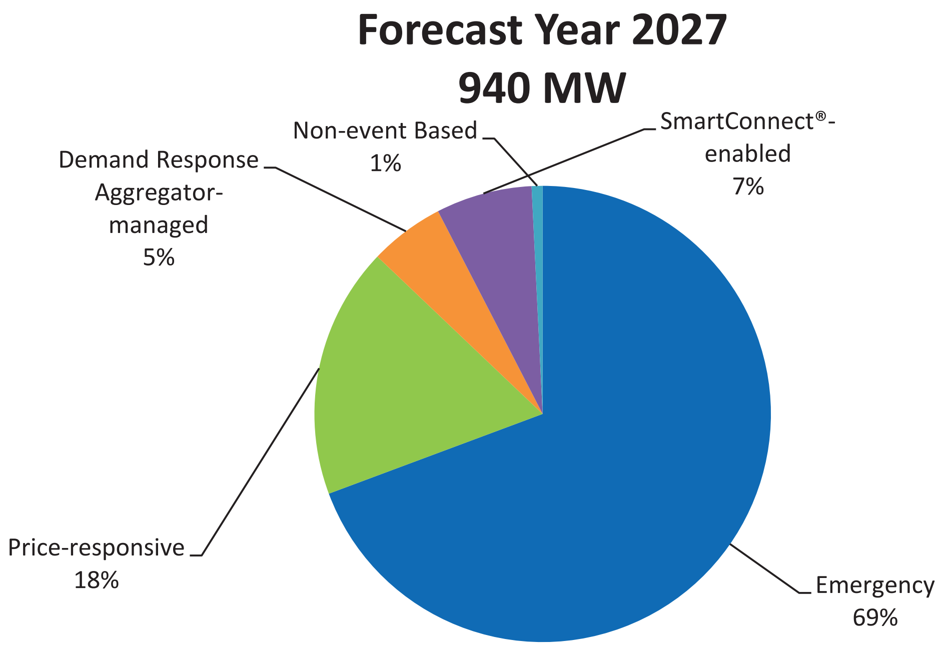
7 *2017 load impacts for Permanent Load Shifting (PLS) are not included in this sum, since they are confidential.

Figure 5-4: Distribution of Portfolio Aggregate Load Impacts by Program Type 2027 August System Peak Day under 1-in-2 SCE-specific System Conditions



5.4 Portfolio Load Impacts by Program

Table 5-1 summarizes the portfolio load impacts by program by month for 2017 through 2027 under 1-in-2 system peak conditions. As indicated in the above discussion of Figure 5-1, load impacts from SCE's DR portfolio are projected to fall by 15% from 2017 to 2027.

Tables 5-2 and 5-3 show the monthly variation in portfolio aggregate load impacts in 2017 for 1-in-2 and 1-in-10 SCE-specific system peaking conditions. Similar tables are presented in Appendices C through F for each forecast year from 2017 through 2027, for 1-in-2 and 1-in-10 SCE-specific system conditions and for both portfolio-adjusted and program-specific assumptions. Appendices G through J present the same tables but under 1-in-2 and 1-in-10 CAISO peaking conditions.

Table 5-1: Portfolio Aggregate Load Impact Estimates (MW) for the August System Peak Day Under 1-in-2 SCE-specific System Conditions by Program and Forecast Year

Program Type	Program	Forecast Year										
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Emergency	BIP-15	149	148	147	145	140	140	140	140	140	140	140
	BIP-30	511	501	489	479	470	462	462	462	462	462	462
	AP-I	50	50	51	50	50	49	49	49	49	49	49
	SUB-TOTAL	**710**	**699**	**686**	**675**	**660**	**650**	**650**	**650**	**650**	**650**	**651**
Price-responsive	SDP-C	36	34	31	29	26	24	22	20	19	17	16
	SDP-R	213	202	192	183	174	165	157	149	141	134	127
	CPP-Large	17	17	17	17	17	17	17	17	17	17	17
	CPP-Medium	0	0	4	11	4	4	4	4	4	4	4
	CPP-Small	0	0	1	8	3	3	3	3	3	3	3
	DBP	6	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**272**	**253**	**245**	**247**	**224**	**213**	**203**	**193**	**184**	**175**	**167**
Demand Response Aggregator-managed	CBP-DA	2	5	5	5	5	5	5	5	5	5	5
	CBP-DO	29	45	45	45	45	45	45	45	45	45	45
	AMP	79	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**110**	**50**	**50**	**50**	**50**	**50**	**50**	**50**	**50**	**50**	**50**
SmartConnect®-enabled	SPD with Tech.	11	19	24	29	34	39	44	49	54	59	64
	SUB-TOTAL	**11**	**19**	**24**	**29**	**34**	**39**	**44**	**49**	**54**	**59**	**64**
Non-event Based	RTP	1	1	1	1	1	1	1	1	1	1	1
	PLS	0*	4	6	6	6	7	7	7	7	7	7
	SUB-TOTAL	**1**	**5**	**7**	**7**	**7**	**8**	**8**	**8**	**8**	**8**	**8**
PORTFOLIO TOTAL		**1,104**	**1,026**	**1,012**	**1,008**	**975**	**960**	**955**	**950**	**946**	**942**	**940**

*Load impacts are redacted to protect confidential customer information

Table 5-2: 2017 Portfolio Aggregate Ex Ante Load Impact Estimates for SCE-specific 1-in-2 System Conditions

Program Type	Program	Monthly System Peak											
		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Emergency	BIP-15	109	121	129	120	136	147	148	149	149	150	142	123
	BIP-30	432	437	433	469	502	490	489	511	486	500	453	433
	AP-I	22	25	31	43	49	53	52	50	40	37	28	26
	SUB-TOTAL	**563**	**583**	**593**	**631**	**687**	**691**	**689**	**710**	**675**	**687**	**623**	**581**
Price-responsive	SDP-C	9	10	10	21	23	25	29	36	32	30	15	8
	SDP-R	0	0	0	53	86	122	171	213	164	123	28	0
	CPP-Large	8	8	8	17	17	17	16	17	17	18	8	8
	CPP-Medium	0	0	0	0	0	0	0	0	0	0	0	0
	CPP-Small	0	0	0	0	0	0	0	0	0	0	0	0
	DBP	3	3	3	3	5	6	6	6	6	6	4	3
	SUB-TOTAL	**20**	**21**	**21**	**93**	**132**	**170**	**222**	**272**	**219**	**177**	**55**	**19**
Demand Response Aggregator-managed	CBP-DA	1	1	1	1	1	1	2	2	2	2	1	1
	CBP-DO	24	25	24	26	23	28	28	29	33	32	24	23
	AMP	82	82	82	82	80	78	77	79	77	77	83	83
	SUB-TOTAL	**107**	**108**	**107**	**109**	**104**	**107**	**107**	**110**	**112**	**111**	**108**	**108**
SmartConnect®-enabled	SPD with Tech.	0	0	-1	6	7	8	10	11	10	10	0	1
	SUB-TOTAL	**0**	**0**	**-1**	**6**	**7**	**8**	**10**	**11**	**10**	**10**	**0**	**1**
Nonevent Based	RTP	0	0	0	0	0	-1	-1	1	-1	0	0	0
	PLS	0*	0*	0*	0*	0*	0*	0*	0*	0*	0*	0*	0*
	SUB-TOTAL	**0**	**0**	**0**	**0**	**0**	**-1**	**-1**	**1**	**-1**	**0**	**0**	**0**
PORTFOLIO TOTAL		**690**	**713**	**720**	**840**	**929**	**974**	**1,026**	**1,104**	**1,016**	**985**	**787**	**708**

*Load impacts are redacted to protect confidential customer information

Table 5-3: 2017 Portfolio Aggregate Ex Ante Load Impact Estimates for SCE-specific 1-in-10 System Conditions

Program Type	Program	Monthly System Peak											
		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Emergency	BIP-15	106	117	132	123	137	147	149	149	149	149	143	121
	BIP-30	435	433	434	473	515	506	495	518	499	506	460	435
	AP-I	24	25	34	48	54	55	53	53	43	42	33	25
	SUB-TOTAL	**565**	**575**	**600**	**645**	**706**	**708**	**697**	**720**	**691**	**697**	**636**	**581**
Price-responsive	SDP-C	7	9	14	29	34	32	35	40	41	34	20	7
	SDP-R	0	0	6	126	183	189	231	256	245	168	97	0
	CPP-Large	8	8	8	18	17	16	15	16	17	18	9	8
	CPP-Medium	0	0	0	0	0	0	0	0	0	0	0	0
	CPP-Small	0	0	0	0	0	0	0	0	0	0	0	0
	DBP	3	3	3	4	6	6	6	6	6	6	4	3
	SUB-TOTAL	**18**	**20**	**32**	**177**	**241**	**243**	**288**	**318**	**310**	**226**	**130**	**18**
Demand Response Aggregator-managed	CBP-DA	1	1	1	1	1	1	2	2	2	2	1	1
	CBP-DO	24	25	25	26	23	28	28	29	33	32	24	23
	AMP	83	82	82	82	80	78	77	79	77	77	83	83
	SUB-TOTAL	**108**	**108**	**109**	**109**	**104**	**107**	**107**	**110**	**112**	**111**	**108**	**108**
SmartConnect®-enabled	SPD with Tech.	1	1	0	8	10	10	11	12	13	11	1	1
	SUB-TOTAL	**1**	**1**	**0**	**8**	**10**	**10**	**11**	**12**	**13**	**11**	**1**	**1**
Nonevent Based	RTP	0	0	0	2	0	-1	4	1	6	2	1	0
	PLS	0*	0*	0*	0*	0*	0*	0*	0*	0*	0*	0*	0*
	SUB-TOTAL	**0**	**0**	**0**	**2**	**0**	**-1**	**4**	**1**	**6**	**2**	**1**	**0**
PORTFOLIO TOTAL		**692**	**705**	**740**	**940**	**1,060**	**1,065**	**1,107**	**1,161**	**1,131**	**1,047**	**877**	**708**

*Load impacts are redacted to protect confidential customer information

6 Recommendations

The 2016 DR program evaluations contain recommendations for each program. The recommendations provide steps to improve the measurement and evaluation of DR resources and to improve program performance. This section summarizes the recommendations for each program.

6.1 Emergency Programs

Overall, emergency programs are infrequently used, but substantial load reductions are linked to both automated control technology and contractual agreements with substantial penalties for nonperformance. Their importance and infrequent dispatch make it critical to understand the electricity use patterns of participants, call test events, and measure the extent to which communications work well. The following summarizes the recommendations for the emergency programs:

- **Continue to call at least one BIP event each year**, especially in light of the fact that the mix of customers on the program can and does change from year to year. When calling a test event, consider the event conditions that are being simulated. If a BIP test event is meant to simulate a generation supply shortage, give at least one day notice, but not the exact timing of the event. If a BIP test event is meant to simulate a transmission or distribution outage, day-ahead notice is not appropriate.
- **Improve the AP-I switch success rate.** This is an iterative process that will take several years and require continuous adjustment to meet stated goals. Improvement requires the following steps:
    1. **Run tests or actual events during the summer, when pumps are on.** Ideally, the test event would occur during peak hours and last long enough to determine whether pumps that were operating immediately before the event ramped down when the event signal was sent to the switches. Calling events facilitates the ability to identify pumps that are not providing load reduction and improve the switch success rates to work toward SCE's goal of improving AP-I switch success rates to 93%.
    2. **Analyze the 15-minute interval data to identify units that were on immediately prior to the event but were not activated.** The criteria for determining activation must take into account that some pumps ramp down over five minutes and that additional loads not controlled by switches are measured by the same meter for a small fraction of participants.
    3. **Target the identified accounts for a switch activation inspection and repair, as appropriate.**

6.2 Price-responsive Programs

Price responsive programs are dispatched more frequently based on economic criteria rather than solely for emergency conditions. The following recommendations were made for price response programs:

- Consider the flexibility of the SDP in assessing the value of the program. Ex ante load impacts for 1 to 6 PM may not reflect the overall value of the program, which can be dispatched locally and can meet the need for system resources during the late afternoon and early hours.

- When choosing the dates for SDP-C events, factor in the school calendar, since schools can deliver a large fraction of SDP-C's potential impact.

6.3 Aggregator-managed Programs

- Continue to offer AutoDR enrollment. It has incrementally higher impacts.
- Consider customer mix, as larger customers have higher impacts.

6.4 SmartConnect®-enabled Programs

Consider redesigning program hours for the SPD PCT program. The PCT program is dispatched from 2 to 6 PM, whereas the resource adequacy peak hours are from 1 to 6 PM. The PCTs precool during the hour before the program event, the first hour of the RA window, resulting in a significant negative load impact during the first hour of the RA window calculation. The difference in the average hourly load impact between the program event window and the RA window is 0.26 kW. This difference results in a 33% lower average hourly impact for the RA window directly attributable to the timing of the program event hours relative to the RA hours.

6.5 Nonevent Based Programs

- **Recruit more large customers into RTP.** Future aggregate load impacts are closely tied to the size and price responsiveness of specific RTP participants.
- **Assess the incremental improvement of different pricing schedule selection rules for RTP.**
- **Each utility should have a process in place to collect and store post-installation operation data. Pre-installation data should be collected.** As more PLS customers come online, it may be possible to relax data collection requirements, but in this early phase it is important to have complete system data, both pre and post-installation.

Appendix A Ex Ante Weather Proxy Days

Table A-1 shows the proxy days selected for SCE-peaking conditions for monthly system peak days coincident with SCE's monthly system peaking conditions. Table A-2 presents the proxy days selected for CAISO-peaking conditions for monthly system peak days coincident with CAISO's monthly system peaking conditions.

Table A-1: SCE Proxy Days in Monthly System Peak Day Selection

Weather Year	Month											
	Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
1-in-10	1/29/2002	2/8/2006	3/20/2006	4/30/1996	5/28/1997	6/5/2002	7/28/1995	8/5/1997	9/1/1998	10/7/1996	11/3/1997	12/18/2006
	1/4/2005	2/27/2007	3/12/2007	4/26/2004	5/3/2004	6/28/2006	7/16/1998	8/29/1998	9/4/2007	10/1/2008	11/7/2006	12/18/2007
	1/16/2007	2/4/2008	3/24/2008	4/28/2008	5/19/2008	6/20/2008	7/25/2006	8/31/2007	9/27/2010	10/13/2011	11/14/2007	12/17/2008
	1/23/2008	2/9/2009	3/31/2011	4/21/2009	5/13/2013	6/28/2013	7/16/2010	8/10/2012	9/5/2013	10/1/2012	11/4/2010	12/9/2013
1-in-2	1/4/1995	2/19/1997	3/15/1999	4/21/1997	5/29/2002	6/23/1995	7/12/1999	8/11/2000	9/5/1995	10/8/1999	11/12/1996	12/21/1998
	1/22/1996	2/23/2000	3/6/2000	4/27/2007	5/20/2005	6/26/2000	7/8/2002	8/10/2004	9/28/1999	10/1/2001	11/1/1999	12/10/2001
	1/26/1999	2/21/2002	3/19/2001	4/1/2011	5/7/2009	6/21/2005	7/13/2005	8/27/2009	9/12/2000	10/7/2002	11/8/2001	12/29/2004
	1/12/2009	2/15/2012	3/10/2005	4/20/2012	5/31/2012	6/29/2007	7/26/2007	8/30/2013	9/14/2012	10/24/2007	11/3/2009	12/19/2012

Table A-2: CAISO Proxy Days in Monthly System Peak Day Selection

Weather Year	Month											
	Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
1-in-10	1/29/2002	2/26/1996	3/19/1997	4/30/1996	5/28/2003	6/22/2001	7/27/1995	8/5/1997	9/3/2007	10/1/2001	11/3/1997	12/18/2006
	1/15/2007	2/21/2002	3/29/2004	4/26/2004	5/3/2004	6/29/2006	7/29/1996	8/31/2007	9/3/2009	10/1/2008	11/29/2006	12/17/2007
	1/24/2008	2/27/2007	3/20/2006	4/28/2008	5/16/2008	6/20/2008	7/3/2001	8/25/2010	9/27/2010	10/1/2010	11/14/2007	12/17/2008
	1/14/2013	2/4/2008	3/12/2007	4/21/2009	5/13/2013	6/28/2013	7/24/2006	8/13/2012	9/7/2011	10/1/2012	11/4/2010	12/8/2009
1-in-2	1/11/2001	2/9/1999	3/16/1999	4/24/1995	5/30/1995	6/30/1996	7/17/1998	8/25/1999	9/4/2003	10/7/1996	11/1/1999	12/12/2000
	1/5/2004	2/23/2000	3/6/2000	4/21/1997	5/29/2002	6/29/1999	7/12/1999	8/14/2003	9/7/2004	10/16/1997	11/5/2001	12/18/2002
	1/5/2009	2/2/2004	3/3/2009	4/21/1998	5/17/2006	6/5/2002	7/16/2003	8/26/2005	9/14/2012	10/7/2004	11/19/2002	12/1/2004
	1/10/2011	2/28/2012	3/7/2013	4/29/2013	5/18/2009	6/29/2009	7/21/2005	8/28/2009	9/6/2013	10/13/2005	11/30/2011	12/13/2010

Appendix B Regression Specifications

B.1 Base Interruptible Program

Ex post:

$$kW_t = A + \sum_{i=1}^{24} B_i \times Hour_i \times BIP\_Eventday_t + \sum_{i=1}^{24} C_i \times Hour_i \times CPP\_Eventday_t + \sum_{i=1}^{24} D_i \times Hour_i \times DBP\_Eventday_t + \sum_{i=1}^{24} E_i \times Hour_i \times \text{morningload} + \sum_{i=1}^{5} F_i \times DOW_t + + \sum_{i=1}^{24} G_i \times Hour_i \times \text{Monday} + \sum_{i=1}^{24} H_i \times Hour_i \times \text{Summer} + \sum_{i=1\text{ s}}^{24} I_i \times Hour_i \times \text{Summer } \times \text{CDH\_MA3} + \sum_{i=1}^{24} J_i \times Hour_i \times \text{Winter } \times \text{CDH60} + \sum_{i=1}^{24} K_i \times Hour_i \times \text{Winter } \times \text{HDH60} + \sum_{i=1}^{24} L_i \times Hour_i \times \text{Winter } \times \text{mean17} + \sum_{i=1}^{24} M_i \times Hour_i \times \text{Friday } + \sum_{m=1}^{12} N_i \times\ Month_m\ if\ year == 2016$$

Variable	Description
kW_t	hourly BIP customer load at time t
A	estimated constant term
$B - O$	estimated parameters
CDD_t	cooling degree days (base 60)
CDH_t	cooling degree hours (base 60)
CDH_t	cooling degree hours (base 60) per day
HDH_t	heating degree hours (base 60) per day
$MorningLoad$	average customer load between 12 AM and 9 AM
$OvernightCDH$	total number of cooling degree hours (base 60) between 12am and 10am
$DayType_j$	series of binary variables representing five different day types (Mon., Tues.-Thurs., Fri., Sat., Sun./Holiday)
$Month_j$	series of binary variables for each month
$Hour_i$	series of binary variables for each hour, which is interacted with all of the remaining variables because each has an impact that varies by hour
$CDH_{MA3\,t}$	moving average of 3 prior cooling degree hours (base 60)
$CPP\_Eventday_t$, $BIP\_Eventday_t$, $DBP\_Eventday_t$, $DRC\_Eventday_t$	binary variable representing each program event day if customer is also enrolled in that program
$Summer_t, Winter_t$	binary variables that indicate if month is between May and October for each hour
e_t	error term

B.2 Agricultural and Pumping Interruptible Program

$$kW_t = A + \sum_{i=1}^{24}\sum_{j=1}^{12} B_{ij} \times Hour_i \times Month_j + \sum_{i=1}^{24}\sum_{j=1}^{3} C_{ij} \times Hour_i \times DayType_j +$$
$$\sum_{i=1}^{24} D_i \times Hour_i \times TotalCDH_t + \sum_{i=1}^{24} E_i \times Hour_i \times TotalCDHsqr_t +$$
$$\sum_{i=1}^{24} F_i \times Hour_i \times TotalHDH_t + \sum_{i=1}^{24} G_i \times Hour_i \times TotalHDHsqr_t +$$
$$\sum_{i=1}^{24} H_i \times Hour_i \times Eventday + \sum_{i=1}^{12} I_i \times Month_i \times TotalCDH_t +$$
$$\sum_{i=1}^{24} J_i \times Hour_i \times MorningLoad \; + \; \varepsilon_t$$

Variable	Definition
kW_t	average hourly demand (kW) for each time period
A	estimated constant term
B_{ij} through J_i	regression model parameters
$Hour_i$	series of binary variables for each hour, which account for the basic hourly load shape of the customer after other factors such as weather and prices are accounted for
$DayType_j$	series of binary variables representing three different day types (Monday, Tuesday-Thursday, and Friday); weekends are excluded from the model
$Month_j$	series of binary variables for each month designed to reflect seasonality in loads
$TotalCDH_t$	sum of cooling degree hours (base 60) for the day
$TotalCDHsqr_t$	$TotalCDH_t$ squared
$TotalHDH_t$	sum of heating degree hours (base 60) for the day
$TotalHDHsqrt$	$TotalHDH_t$ squared
$EventDay_t$	binary variable representing an AP-I event day
$MorningLoad$	average kW between 12 AM and 12 PM for each customer and day
e_t	error term

B.3 Critical Peak Pricing

Matched control group regression:

$$kW_{i,t,h} = a * treat_i * eday_t * eperiod_h + \sum_{cust=1}^{customers} b_{cust} * customer_{cust\ i} + \sum_{hr=1}^{hours} c_{hr} * hour_{hr\ h}$$
$$+ \sum_{date=1}^{days} d_{date} * day_{date\ t} + e * eday_t * eperiod_h + f * treat_i * eperiod_h$$
$$+ g * treat_i * eday_t + u_{ith}$$

Variable	Description
kW	average demand
treat	indicates whether a customer is a participant (treat=1) or a control group member (treat =0)
eday	indicates whether a given day was an event (eday=1) or not (eday=0)
eperiod	indicates whether a given hour was an event hour (eperiod=1) or not (eperiod=0)
customer	a set of indicator variables that equal one if cust=i
hour	a set of indicator variables that equal one if hr=h
day	a set of indicator variables that equal one if date=t
a	estimated effect of the treatment
b, c, d	estimated fixed effects
e, f, g	estimated parameters
i	indexes customers
t	indexes the days
h	indexes hours

Ex post, individual event

$$kwh_{it} = a + b * mean17_{i,t} + c * mean17_{i,t}^2 + e_{i,t}$$

Variable	Description
A	a is an estimated constant
b, c, and d	b, c, and d are estimated parameters
mean17	mean temperature from midnight until 5 PM
e	error term

12 models tested:

Model #	Specification
1	$P(CPP_i) = \Phi\left(a + \sum_{h=12}^{21} b_h * kW_{hi} + e_i\right)$
2	$P(CPP_i) = \Phi\left(a + \sum_{h=12}^{21} b_h * kW_{hi} + c * Avg\ Summer\ Day\ kWh_i + e_i\right)$
3	$P(CPP_i) = \Phi\left(a + \sum_{h=12}^{21} b_h * kW_{hi} + c * Avg\ Proxy\ Day\ kWh_i + e_i\right)$
4	$P(CPP_i) = \Phi\left(a + \sum_{h=12}^{21} b_h * kW_{hi} + c * Avg\ Summer\ Day\ kWh_i + d * Proxy\ Day\ Percent\ Peak\ Usage_i + e_i\right)$
5	$P(CPP_i) = \Phi\left(a + \sum_{h=12}^{21} b_h * kW_{hi} + c * Avg\ Proxy\ Day\ kWh_i + d * Proxy\ Day\ Percent\ Peak\ Usage_i + e_i\right)$
6	$P(CPP_i) = \Phi\left(a + \sum_{h=15}^{18} b_h * kW_{hi} + e_i\right)$
7	$P(CPP_i) = \Phi\left(a + \sum_{h=15}^{18} b_h * kW_{hi} + c * Avg\ Summer\ Day\ kWh_i + e_i\right)$
8	$P(CPP_i) = \Phi\left(a + \sum_{h=15}^{18} b_h * kW_{hi} + c * Avg\ Proxy\ Day\ kWh_i + e_i\right)$

Model #	Specification
9	$P(CPP_i) = \Phi\left(a + \sum_{h=15}^{18} b_h * kW_{hi} + c * Avg\ Summer\ Day\ kWh_i + d * Proxy\ Day\ Percent\ Peak\ Usage_i + e_i\right)$
10	$P(CPP_i) = \Phi\left(a + \sum_{h=15}^{18} b_h * kW_{hi} + c * Avg\ Proxy\ Day\ kWh_i + d * Proxy\ Day\ Percent\ Peak\ Usage_i + e_i\right)$
11	$P(CPP_i) = \Phi(a + b * Avg\ Summer\ Day\ kWh_i + c * Proxy\ Day\ Percent\ Peak\ Usage_i + e_i)$
12	$P(CPP_i) = \Phi(a + b * Avg\ Summer\ Day\ kWh_i + c * Proxy\ Day\ Percent\ Peak\ Usage_i + e_i)$

Variable	Description
kW	energy usage in each hourly interval h averaged over proxy days
Avg Summer Day kWh	total energy usage for all hours in a day averaged over nonevent summer days
Avg Proxy Day kWh	total energy usage for all hours in a day averaged over proxy days
Proxy Day Percent Peak Usage	percentage of total energy occurring in peak hours averaged over proxy days

B.4 Demand Bidding Program

Ex post:

$$Q_t = a + \sum_{Evt=1}^{E} \sum_{i=1}^{24} (b_{i,Evt}^{DBP} \times h_{i,t} \times DBP_t) + \sum_{i=1}^{24} (b_i^{MornLoad} \times h_{i,t} \times MornLoad_{i,t})$$
$$+ \sum_{DR} \sum_{i=1}^{24} (b_i^{DR} \times h_{i,t} \times OtherEvt^{DR}{}_{i,t}) + \sum_{i=1}^{24} (b_i^{Weather} \times h_{i,t} \times Weather_t) + \sum_{i=2}^{24} (b_i^{MON} \times h_{i,t} \times MON_t)$$
$$+ \sum_{i=2}^{24} (b_i^{FRI} \times h_{i,t} \times FRI_t) + \sum_{i=2}^{24} (b_i^{SUMMER} \times h_{i,t} \times SUMMER_t) + \sum_{i=2}^{24} (b_i^{h} \times h_{i,t})$$
$$+ \sum_{i=2}^{5} (b_i^{DTYPE} \times DTYPE_{i,t}) + \sum_{i=6}^{10} (b_i^{MONTH} \times MONTH_{i,t}) + e_t$$

Variable	Description
Q_t	demand in hour t for a customer enrolled in DBP prior to the last event date
b's	estimated parameters
$h_{i,t}$	dummy variable for hour i
DBP_t	indicator variable for program event days
$Weather_t$	weather variables selected in the model screening process
E	number of event days that occurred during the program year
$MornLoad_t$	variable equal to the average of the day's load in hours 1 through 10
$OtherEvt_{i,t}^{DR}$	equals one on the event days of other demand response programs in which the customer is enrolled
MON_t	dummy variable for Monday
FRI_t	dummy variable for Friday
$SUMMER_t$	dummy variable for the summer pricing season[8]
$DTYPE_{i,t}$	series of dummy variables for each day of the week
$MONTH_{i,t}$	series of dummy variables for each month
e_t	error term

The ex ante model specifications used for estimating summer loads are the same as the ex post specifications, with the following exceptions:

- The $MornLoad_{i,t}$ term and the E term are not included in the ex ante model specification; and
- A cooling degree hour (base 60 °F) variable is used in the ex ante model specification rather than the $Weather_t$ term.

8 The SCE summer pricing season is June through September.

- The ex ante model specification used for estimating non-summer loads follows, which uses the same variable naming convention as in the ex post regression model specification, with the addition of the HDH_t and HDD_t variables, heating degree hours, and heating degree days, base 60 °F.

$$
\begin{aligned}
Q_t &= a + \sum_{Evt=1}^{E} \sum_{i=1}^{24} (b_{i,Evt}^{DBP} \times h_{i,t} \times DBP_t) + \sum_{DR} \sum_{i=1}^{24} (b_i^{DR} \times h_{i,t} \times OtherEvt^{DR}{}_{i,t}) \\
&+ \sum_{i=1}^{24} (b_i^{CDH} \times h_{i,t} \times CDH_t) + \sum_{i=1}^{24} (b_i^{CDD} \times h_{i,t} \times CDD_t) + \sum_{i=1}^{24} (b_i^{HDH} \times h_{i,t} \times HDH_t) \\
&+ \sum_{i=1}^{24} (b_i^{HDD} \times h_{i,t} \times HDD_t) + \sum_{i=2}^{24} (b_i^{MON} \times h_{i,t} \times MON_t) + \sum_{i=2}^{24} (b_i^{FRI} \times h_{i,t} \times FRI_t) + \sum_{i=2}^{24} (b_i^{h} \times h_{i,t}) \\
&+ \sum_{i=2}^{5} (b_i^{DTYPE} \times DTYPE_{i,t}) + \sum_{i=2-5,10-12} (b_i^{MONTH} \times MONTH_{i,t}) + e_t
\end{aligned}
$$

B.5 Capacity Bidding Program and Aggregator Managed Programs

Approximately 35 regression model specifications were tested for each customer, where 25 include terms that account for weather-sensitive loads and 10 do not, for customers with electric loads that are not weather-sensitive. Each of the 35 models used different combinations of the explanatory variables described in the table below. The best model was selected for each customer on the basis of out-of-sample testing, using mean absolute percent error and mean percent error as points of comparison.

Variable Name	Variable Description
$Weather_{i,d}$	weather-related variables including average daily temperature, multiple cooling degree hour (CDH) terms with base values of 75, 70, and 65 depending on service territory, and lagged versions of various weather related variables
$Month_{i,d}$	series of indicator variables for each month
$DayOfWeek_{i,d}$	series of indicator variables for each day of the week
$Year_{i,d}$	indicator for the year 2016
$OtherEvt_{i,d}$	binary variable that equals one on event days of other demand response programs in which the customer is enrolled
$MornLoad_{i,d}$	average of each day's load in hours 5 am through 10 am
$P_{i,d}$	indicator for aggregator program event days
$P * Month_{i,d}$	indicator variable for aggregator program event days interacted with the month
$P * Year_{i,d}$	indicator variable for aggregator program event days interacted with the year 2016
$P*NonTypEvent_{i,d}$	indicator variable for aggregator program event days interacted with an indicator for non-typical event windows (outside of HE 16-19)

B.6 Save Power Day

Ex ante:

$$Impact = a + b \cdot mean17 \ + \boldsymbol{\varepsilon}$$

Variable	Description
$Impact$	per customer ex post load impact (kW) for each event day, averaged over the event period
a	estimated constant
b	estimated parameter coefficient
$mean17$	average temperature from 12 AM to 5 PM
$\boldsymbol{\varepsilon}$	error term, assumed to be mean zero and uncorrelated with any of the independent variables

B.7 Real Time Pricing

$$\begin{aligned} kW_t = A &+ \sum_{i=13}^{22} B_i \times Hour_i \times Price_t + \sum_{i=13}^{22} C_i \times Hour_i \times PriceSQR_t \\ &+ \sum_{i=1}^{12} D_i \times Hour_i \times PriceRatio_t + \sum_{i=23}^{24} E_i \times Hour_i \times PriceRatio_t \\ &+ \sum_{i=1}^{24} \sum_{j=1}^{3} F_{ij} \times Hour_i \times DayType_j + \sum_{i=1}^{24} \sum_{j=1}^{12} G_{ij} \times Hour_i \times Month_j + e_t \end{aligned}$$

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

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

Variable	Description
A	estimated constant
$B - J$	estimated parameter coefficients
$Hour$	indicator variables representing the hours of the day, designed to estimate the effect of daily schedules on usage behavior and event impacts
$Month$	indicator variable for the month
$Price$	RTP price in effect for each hour
$PriceSQR$	RTP price squared
$PriceRatio$	ratio between the RTP price in effect for each hour and the maximum price for the day, which captures load shifting to hours when prices are relatively low

Variable	Description
$DayType$	series of binary variables representing three different day types (Monday, Tuesday through Thursday, and Friday)
$TotalCDH$	total number of cooling degree hours (base 70) per day
$TotalHDH$	total number of heating degree hours (base 70) per day
e_t	error term

B.8 Permanent Load Shifting

$$kW_t = A + \sum_{i=1}^{24}\sum_{j=1}^{12} B_{ij} \times Hour_i \times Month_j + \sum_{i=1}^{24}\sum_{j=1}^{5} C_{ij} \times Hour_i \times DOW_j +$$
$$\sum_{i=1}^{24} D_i \times Hour_i \times CDD_t + \sum_{i=1}^{24} E_i \times Hour_i \times CDDsqr_t +$$
$$\sum_{i=1}^{24} F_i \times Hour_i \times CDH_t + \sum_{i=1}^{24} G_i \times Hour_i \times CDHsqr_t +$$
$$\sum_{i=1}^{24} H_i \times Hour_i \times Summer + \sum_{i=1}^{3} I_i \times Year_{it} +$$
$$J_i \times PLS_t + \varepsilon_t$$

Variable	Definition
kW_t	average hourly demand (kW) for each time period
A	estimated constant term
B_{ij} through J_i	regression model parameters
$Hour_i$	series of binary variables for each hour, which account for the basic hourly load shape of the customer after other factors such as weather and prices are accounted for
DOW_j	series of binary variables representing weekdays (Mon-Fri); weekends and holidays are excluded from the model. Energy use immediately before or after a weekend may be different compared to load in the middle of the week.
$Month_j$	series of binary variables for each month designed to reflect seasonality in loads
CDD_t	cooling degree day – the maximum of zero and the mean temperature of the day of the hourly observation less a base value 60 °F
$CDDsqr_t$	CDD_t squared
CDH_t	cooling degree hour – the maximum of zero and the hourly temperature less a base value 60 °F

Variable	Definition
$CDHsqr_t$	CDH_t squared
$Summer_t$	binary variable reflecting summer months of July through October
PLS_t	binary variable reflecting when the TES system is operational
e_t	error term

Appendix C Portfolio Aggregate Ex Ante Load Impact Estimates for 1-in-2 SCE-specific System Conditions by Month and Forecast Year

Table C-1: 2017 Portfolio Aggregate Ex Ante Load Impact Estimates for 1-in-2 SCE-specific System Conditions

Program Type	Program	Monthly System Peak											
		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Emergency	BIP-15	109	121	129	120	136	147	148	149	149	150	142	123
	BIP-30	432	437	433	469	502	490	489	511	486	500	453	433
	AP-I	22	25	31	43	49	53	52	50	40	37	28	26
	SUB-TOTAL	**563**	**583**	**593**	**631**	**687**	**691**	**689**	**710**	**675**	**687**	**623**	**581**
Price-responsive	SDP-C	9	10	10	21	23	25	29	36	32	30	15	8
	SDP-R	0	0	0	53	86	122	171	213	164	123	28	0
	CPP-Large	8	8	8	17	17	17	16	17	17	18	8	8
	CPP-Medium	0	0	0	0	0	0	0	0	0	0	0	0
	CPP-Small	0	0	0	0	0	0	0	0	0	0	0	0
	DBP	4	4	4	5	5	5	5	5	5	5	5	4
	SUB-TOTAL	**21**	**22**	**22**	**95**	**132**	**169**	**221**	**271**	**219**	**176**	**56**	**20**
Demand Response Aggregator-managed	CBP-DA	1	1	1	1	1	1	2	2	2	2	1	1
	CBP-DO	24	25	24	26	23	28	28	29	33	32	24	23
	AMP	82	82	82	82	80	78	77	79	77	77	83	83
	SUB-TOTAL	**107**	**108**	**107**	**109**	**104**	**107**	**107**	**110**	**112**	**111**	**108**	**108**
SmartConnect®-enabled	SPD with Tech.	0	0	-1	6	7	8	10	11	10	10	0	1
	SUB-TOTAL	**0**	**0**	**-1**	**6**	**7**	**8**	**10**	**11**	**10**	**10**	**0**	**1**
Nonevent Based	RTP	0	0	0	0	0	-1	-1	1	-1	0	0	0
	PLS	0*	0*	0*	0*	0*	0*	0*	0*	0*	0*	0*	0*
	SUB-TOTAL	**0**	**0**	**0**	**0**	**0**	**-1**	**-1**	**1**	**-1**	**0**	**0**	**0**
PORTFOLIO TOTAL		**691**	**714**	**721**	**841**	**929**	**974**	**1,025**	**1,103**	**1,015**	**984**	**788**	**709**

*Load impacts are redacted to protect confidential customer information

Table C-2: 2018 Portfolio Aggregate Ex Ante Load Impact Estimates for 1-in-2 SCE-specific System Conditions

Program Type	Program	Monthly System Peak											
		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Emergency	BIP-15	126	139	136	126	138	147	148	148	148	149	141	122
	BIP-30	433	436	430	465	496	484	482	501	477	491	445	425
	AP-I	22	26	32	44	50	54	52	50	41	38	28	26
	SUB-TOTAL	**581**	**601**	**598**	**635**	**684**	**685**	**683**	**699**	**665**	**678**	**613**	**572**
Price-responsive	SDP-C	8	9	10	19	22	24	27	34	30	27	14	7
	SDP-R	0	0	0	50	82	116	162	202	155	117	27	0
	CPP-Large	8	8	8	17	17	17	16	17	17	18	8	8
	CPP-Medium	0	0	0	0	0	0	0	0	0	4	1	1
	CPP-Small	0	0	0	0	0	0	0	0	0	1	0	0
	DBP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**16**	**17**	**17**	**86**	**121**	**156**	**205**	**252**	**203**	**167**	**51**	**16**
Demand Response Aggregator-managed	CBP-DA	3	3	3	3	3	4	5	5	6	6	3	3
	CBP-DO	37	38	37	40	35	43	43	45	51	49	36	36
	AMP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**40**	**42**	**40**	**43**	**38**	**47**	**48**	**50**	**56**	**54**	**40**	**39**
SmartConnect®-enabled	SPD with Tech.	1	1	-2	11	12	14	16	19	17	17	0	1
	SUB-TOTAL	**1**	**1**	**-2**	**11**	**12**	**14**	**16**	**19**	**17**	**17**	**0**	**1**
Nonevent Based	RTP	0	0	0	0	0	-1	-1	1	-1	0	0	0
	PLS	0	0	0	0	3	3	4	4	4	4	0	0
	SUB-TOTAL	**0**	**0**	**0**	**0**	**3**	**2**	**2**	**5**	**3**	**4**	**0**	**0**
PORTFOLIO TOTAL		**638**	**661**	**654**	**775**	**858**	**904**	**954**	**1,026**	**945**	**919**	**704**	**629**

Table C-3: 2019 Portfolio Aggregate Ex Ante Load Impact Estimates for 1-in-2 SCE-specific System Conditions

Program Type	Program	Monthly System Peak											
		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Emergency	BIP-15	125	138	135	125	137	147	148	146	147	147	139	121
	BIP-30	424	427	422	455	484	472	469	489	465	478	434	414
	AP-I	22	26	32	44	50	54	53	51	41	38	28	26
	SUB-TOTAL	**571**	**591**	**590**	**624**	**671**	**674**	**671**	**686**	**653**	**664**	**601**	**561**
Price-responsive	SDP-C	8	9	9	18	20	22	25	31	28	25	13	7
	SDP-R	0	0	0	47	78	110	154	192	148	111	25	0
	CPP-Large	8	8	8	17	17	17	16	17	17	18	8	8
	CPP-Medium	1	1	1	3	3	4	4	4	4	9	4	3
	CPP-Small	0	0	0	1	1	1	1	1	1	6	4	4
	DBP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**17**	**18**	**18**	**86**	**119**	**153**	**200**	**245**	**197**	**170**	**55**	**22**
Demand Response Aggregator-managed	CBP-DA	3	3	3	3	3	4	5	5	6	6	3	3
	CBP-DO	37	38	37	40	35	43	43	45	51	49	36	36
	AMP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**40**	**42**	**40**	**43**	**38**	**47**	**48**	**50**	**56**	**54**	**40**	**39**
SmartConnect®-enabled	SPD with Tech.	1	1	-2	14	16	18	21	24	22	21	0	1
	SUB-TOTAL	**1**	**1**	**-2**	**14**	**16**	**18**	**21**	**24**	**22**	**21**	**0**	**1**
Nonevent Based	RTP	0	0	0	0	0	-1	-1	1	-1	0	0	0
	PLS	0	0	0	0	5	5	5	6	6	5	0	0
	SUB-TOTAL	**0**	**0**	**0**	**0**	**5**	**3**	**4**	**6**	**4**	**5**	**0**	**0**
PORTFOLIO TOTAL		**629**	**652**	**646**	**767**	**848**	**895**	**943**	**1,012**	**933**	**914**	**695**	**623**

Table C-4: 2020 Portfolio Aggregate Ex Ante Load Impact Estimates for 1-in-2 SCE-specific System Conditions

Program Type	Program	Monthly System Peak											
		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Emergency	BIP-15	124	137	134	124	136	146	147	145	146	146	135	116
	BIP-30	414	415	412	445	474	464	461	479	456	469	425	406
	AP-I	22	26	32	44	50	54	52	50	40	38	28	26
	SUB-TOTAL	**560**	**578**	**578**	**613**	**660**	**664**	**661**	**675**	**642**	**653**	**587**	**548**
Price-responsive	SDP-C	7	8	8	16	19	20	23	29	25	23	12	6
	SDP-R	0	0	0	45	74	105	147	183	141	106	24	0
	CPP-Large	8	8	8	17	17	17	16	17	18	18	8	8
	CPP-Medium	3	3	3	8	8	9	10	11	10	4	1	1
	CPP-Small	4	4	4	5	5	6	7	8	7	2	2	2
	DBP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**22**	**23**	**23**	**91**	**124**	**157**	**202**	**246**	**200**	**153**	**48**	**17**
Demand Response Aggregator-managed	CBP-DA	3	3	3	3	3	4	5	5	6	6	3	3
	CBP-DO	37	38	37	40	35	43	43	45	51	49	36	36
	AMP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**40**	**42**	**40**	**43**	**38**	**47**	**48**	**50**	**56**	**54**	**40**	**39**
SmartConnect®-enabled	SPD with Tech.	1	1	-3	17	19	21	25	29	26	25	0	2
	SUB-TOTAL	**1**	**1**	**-3**	**17**	**19**	**21**	**25**	**29**	**26**	**25**	**0**	**2**
Nonevent Based	RTP	0	0	0	0	0	-1	-1	1	-1	0	0	0
	PLS	0	0	0	0	5	5	6	6	6	5	0	0
	SUB-TOTAL	**0**	**0**	**0**	**0**	**5**	**4**	**4**	**7**	**5**	**5**	**0**	**0**
PORTFOLIO TOTAL		**624**	**645**	**639**	**764**	**846**	**893**	**940**	**1,007**	**929**	**891**	**675**	**606**

Table C-5: 2021 Portfolio Aggregate Ex Ante Load Impact Estimates for 1-in-2 SCE-specific System Conditions

Program Type	Program	Monthly System Peak											
		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Emergency	BIP-15	119	133	130	120	131	142	142	140	141	141	133	115
	BIP-30	405	408	404	436	466	455	452	470	447	460	417	399
	AP-I	22	26	31	44	49	53	52	50	40	37	27	25
	SUB-TOTAL	**546**	**566**	**566**	**599**	**646**	**649**	**646**	**660**	**628**	**637**	**577**	**539**
Price-responsive	SDP-C	7	7	7	15	17	18	21	26	23	22	11	6
	SDP-R	0	0	0	43	71	100	139	174	134	100	23	0
	CPP-Large	8	8	8	17	17	17	16	17	18	18	8	8
	CPP-Medium	1	1	1	3	3	4	4	4	4	4	1	1
	CPP-Small	2	2	2	2	2	3	3	3	3	2	2	2
	DBP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**17**	**18**	**18**	**80**	**110**	**141**	**183**	**224**	**181**	**146**	**46**	**16**
Demand Response Aggregator-managed	CBP-DA	3	3	3	3	3	4	5	5	6	6	3	3
	CBP-DO	37	38	37	40	35	43	43	45	51	49	36	36
	AMP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**40**	**42**	**40**	**43**	**38**	**47**	**48**	**50**	**56**	**54**	**40**	**39**
SmartConnect®-enabled	SPD with Tech.	2	2	-3	20	22	25	29	34	30	30	0	2
	SUB-TOTAL	**2**	**2**	**-3**	**20**	**22**	**25**	**29**	**34**	**30**	**30**	**0**	**2**
Nonevent Based	RTP	0	0	0	0	0	-1	-1	1	-1	0	0	0
	PLS	0	0	0	0	5	6	6	6	6	6	0	0
	SUB-TOTAL	**0**	**0**	**0**	**0**	**5**	**4**	**5**	**7**	**5**	**6**	**0**	**0**
PORTFOLIO TOTAL		**606**	**628**	**622**	**742**	**822**	**867**	**911**	**976**	**901**	**873**	**662**	**597**

Table C-6: 2022 Portfolio Aggregate Ex Ante Load Impact Estimates for 1-in-2 SCE-specific System Conditions

Program Type	Program	Monthly System Peak											
		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Emergency	BIP-15	118	131	129	118	129	140	141	140	140	141	133	115
	BIP-30	397	401	397	427	457	447	443	462	440	453	411	394
	AP-I	22	25	31	43	49	52	51	49	39	36	27	25
	SUB-TOTAL	**537**	**557**	**556**	**587**	**635**	**639**	**634**	**650**	**620**	**630**	**571**	**534**
Price-responsive	SDP-C	6	7	7	14	16	17	19	24	21	20	10	5
	SDP-R	0	0	0	41	67	95	132	165	127	95	22	0
	CPP-Large	8	8	8	17	17	17	16	17	18	18	9	8
	CPP-Medium	1	1	1	3	3	4	4	4	4	4	1	1
	CPP-Small	2	2	2	2	2	3	3	3	3	2	2	2
	DBP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**17**	**18**	**18**	**77**	**105**	**135**	**175**	**213**	**173**	**140**	**44**	**16**
Demand Response Aggregator-managed	CBP-DA	3	3	3	3	3	4	5	5	6	6	3	3
	CBP-DO	37	38	37	40	35	43	43	45	51	49	36	36
	AMP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**40**	**42**	**40**	**43**	**38**	**47**	**48**	**50**	**56**	**54**	**40**	**39**
SmartConnect®-enabled	SPD with Tech.	2	2	-4	23	26	29	33	39	35	34	0	2
	SUB-TOTAL	**2**	**2**	**-4**	**23**	**26**	**29**	**33**	**39**	**35**	**34**	**0**	**2**
Nonevent Based	RTP	0	0	0	0	0	-1	-1	1	-1	0	0	0
	PLS	0	0	0	0	6	6	7	7	7	6	0	0
	SUB-TOTAL	**0**	**0**	**0**	**0**	**6**	**5**	**5**	**7**	**5**	**6**	**0**	**0**
PORTFOLIO TOTAL		**596**	**618**	**611**	**730**	**809**	**854**	**895**	**960**	**889**	**864**	**655**	**591**

Table C-7: 2023 Portfolio Aggregate Ex Ante Load Impact Estimates for 1-in-2 SCE-specific System Conditions

Program Type	Program	Monthly System Peak											
		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Emergency	BIP-15	118	131	129	118	129	140	141	140	140	141	133	115
	BIP-30	394	397	393	425	455	445	443	462	440	453	411	394
	AP-I	22	25	31	43	48	52	51	49	39	36	27	25
	SUB-TOTAL	**533**	**553**	**553**	**586**	**633**	**637**	**634**	**650**	**620**	**630**	**571**	**534**
Price-responsive	SDP-C	6	6	6	13	14	16	18	22	20	18	9	5
	SDP-R	0	0	0	39	64	90	126	157	121	91	21	0
	CPP-Large	8	8	8	17	17	17	16	17	18	18	9	8
	CPP-Medium	1	1	1	3	3	4	4	4	4	4	1	1
	CPP-Small	2	2	2	2	2	3	3	3	3	2	2	2
	DBP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**16**	**17**	**17**	**74**	**101**	**129**	**167**	**203**	**165**	**133**	**42**	**15**
Demand Response Aggregator-managed	CBP-DA	3	3	3	3	3	4	5	5	6	6	3	3
	CBP-DO	37	38	37	40	35	43	43	45	51	49	36	36
	AMP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**40**	**42**	**40**	**43**	**38**	**47**	**48**	**50**	**56**	**54**	**40**	**39**
SmartConnect®-enabled	SPD with Tech.	2	2	-4	25	29	32	38	44	39	38	0	2
	SUB-TOTAL	**2**	**2**	**-4**	**25**	**29**	**32**	**38**	**44**	**39**	**38**	**0**	**2**
Nonevent Based	RTP	0	0	0	0	0	-1	-1	1	-1	0	0	0
	PLS	0	0	0	0	6	6	7	7	7	6	0	0
	SUB-TOTAL	**0**	**0**	**0**	**0**	**6**	**5**	**6**	**8**	**6**	**6**	**0**	**0**
PORTFOLIO TOTAL		**592**	**614**	**606**	**728**	**806**	**850**	**892**	**955**	**885**	**862**	**653**	**591**

Table C-8: 2024 Portfolio Aggregate Ex Ante Load Impact Estimates for 1-in-2 SCE-specific System Conditions

Program Type	Program	Monthly System Peak											
		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Emergency	BIP-15	118	131	129	118	129	140	141	140	140	141	133	115
	BIP-30	394	397	393	425	455	445	443	462	440	453	411	394
	AP-I	22	25	31	43	48	52	51	49	39	36	27	25
	SUB-TOTAL	**533**	**553**	**553**	**586**	**633**	**637**	**634**	**650**	**620**	**630**	**571**	**534**
Price-responsive	SDP-C	5	6	6	12	13	14	16	20	18	17	9	4
	SDP-R	0	0	0	37	61	85	119	149	115	86	20	0
	CPP-Large	8	8	8	17	17	17	16	17	18	18	9	8
	CPP-Medium	1	1	1	3	3	4	4	4	4	4	1	1
	CPP-Small	2	2	2	2	2	3	3	3	3	2	2	2
	DBP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**16**	**17**	**16**	**71**	**97**	**123**	**159**	**193**	**157**	**127**	**40**	**15**
Demand Response Aggregator-managed	CBP-DA	3	3	3	3	3	4	5	5	6	6	3	3
	CBP-DO	37	38	37	40	35	43	43	45	51	49	36	36
	AMP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**40**	**42**	**40**	**43**	**38**	**47**	**48**	**50**	**56**	**54**	**40**	**39**
SmartConnect®-enabled	SPD with Tech.	2	2	-4	28	32	36	42	49	43	42	0	3
	SUB-TOTAL	**2**	**2**	**-4**	**28**	**32**	**36**	**42**	**49**	**43**	**42**	**0**	**3**
Nonevent Based	RTP	0	0	0	0	0	-1	-1	1	-1	0	0	0
	PLS	0	0	0	0	6	6	7	7	7	6	0	0
	SUB-TOTAL	**0**	**0**	**0**	**0**	**6**	**5**	**6**	**8**	**6**	**7**	**0**	**0**
PORTFOLIO TOTAL		**592**	**614**	**605**	**728**	**805**	**848**	**888**	**951**	**882**	**860**	**651**	**591**

Table C-9: 2025 Portfolio Aggregate Ex Ante Load Impact Estimates for 1-in-2 SCE-specific System Conditions

Program Type	Program	Monthly System Peak											
		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Emergency	BIP-15	118	131	129	118	129	140	141	140	140	141	133	115
	BIP-30	394	397	393	425	455	445	443	462	440	453	411	394
	AP-I	22	25	31	43	48	52	51	49	39	36	27	25
	SUB-TOTAL	**533**	**553**	**553**	**586**	**633**	**637**	**634**	**650**	**620**	**630**	**571**	**534**
Price-responsive	SDP-C	5	5	5	11	12	13	15	19	17	15	8	4
	SDP-R	0	0	0	35	57	81	113	141	109	82	19	0
	CPP-Large	8	8	8	17	17	17	16	17	18	18	9	8
	CPP-Medium	1	1	1	3	3	4	4	4	4	4	1	1
	CPP-Small	2	2	2	2	2	3	3	3	3	2	2	2
	DBP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**16**	**16**	**16**	**68**	**92**	**117**	**151**	**184**	**150**	**121**	**38**	**15**
Demand Response Aggregator-managed	CBP-DA	3	3	3	3	3	4	5	5	6	6	3	3
	CBP-DO	37	38	37	40	35	43	43	45	51	49	36	36
	AMP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**40**	**42**	**40**	**43**	**38**	**47**	**48**	**50**	**56**	**54**	**40**	**39**
SmartConnect®-enabled	SPD with Tech.	3	3	-5	31	35	40	46	54	48	46	0	3
	SUB-TOTAL	**3**	**3**	**-5**	**31**	**35**	**40**	**46**	**54**	**48**	**46**	**0**	**3**
Nonevent Based	RTP	0	0	0	0	0	-1	-1	1	-1	0	0	0
	PLS	0	0	0	0	6	6	7	7	7	6	0	0
	SUB-TOTAL	**0**	**0**	**0**	**0**	**6**	**5**	**5**	**8**	**6**	**6**	**0**	**0**
PORTFOLIO TOTAL		**592**	**614**	**604**	**728**	**804**	**846**	**885**	**946**	**879**	**859**	**649**	**591**

Table C-10: 2026 Portfolio Aggregate Ex Ante Load Impact Estimates for 1-in-2 SCE-specific System Conditions

Program Type	Program	Monthly System Peak											
		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Emergency	BIP-15	118	131	129	118	129	140	141	140	140	141	133	115
	BIP-30	394	397	393	425	455	445	443	462	440	453	411	394
	AP-I	22	25	31	43	48	52	51	49	39	36	27	25
	SUB-TOTAL	**533**	**553**	**553**	**586**	**633**	**637**	**634**	**650**	**620**	**630**	**571**	**534**
Price-responsive	SDP-C	4	5	5	10	11	12	14	17	15	14	7	4
	SDP-R	0	0	0	33	54	77	107	134	103	77	18	0
	CPP-Large	8	8	8	17	17	17	16	17	18	18	9	8
	CPP-Medium	1	1	1	3	3	4	4	4	4	4	1	1
	CPP-Small	2	2	2	2	2	3	3	3	3	2	2	2
	DBP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**15**	**16**	**16**	**65**	**88**	**112**	**144**	**175**	**143**	**116**	**37**	**14**
Demand Response Aggregator-managed	CBP-DA	3	3	3	3	3	4	5	5	6	6	3	3
	CBP-DO	37	38	37	40	35	43	43	45	51	49	36	36
	AMP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**40**	**42**	**40**	**43**	**38**	**47**	**48**	**50**	**56**	**54**	**40**	**39**
SmartConnect®-enabled	SPD with Tech.	3	3	-5	34	39	44	51	59	52	50	0	3
	SUB-TOTAL	**3**	**3**	**-5**	**34**	**39**	**44**	**51**	**59**	**52**	**50**	**0**	**3**
Nonevent Based	RTP	0	0	0	0	0	-1	-1	1	-1	0	0	0
	PLS	0	0	0	0	6	6	7	7	7	6	0	0
	SUB-TOTAL	**0**	**0**	**0**	**0**	**6**	**5**	**5**	**7**	**5**	**6**	**0**	**0**
PORTFOLIO TOTAL		**592**	**613**	**603**	**729**	**804**	**844**	**882**	**942**	**876**	**857**	**648**	**591**

Table C-11: 2027 Portfolio Aggregate Ex Ante Load Impact Estimates for 1-in-2 SCE-specific System Conditions

Program Type	Program	Monthly System Peak											
		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Emergency	BIP-15	118	131	129	118	129	140	141	140	140	141	133	115
	BIP-30	394	397	393	425	455	445	443	462	440	453	411	394
	AP-I	22	25	31	43	48	52	51	49	39	36	27	25
	SUB-TOTAL	**533**	**553**	**553**	**586**	**633**	**637**	**634**	**650**	**620**	**630**	**571**	**534**
Price-responsive	SDP-C	4	4	4	9	10	11	12	16	14	13	7	3
	SDP-R	0	0	0	31	52	73	102	127	98	73	17	0
	CPP-Large	8	8	8	17	17	17	16	17	18	18	9	8
	CPP-Medium	1	1	1	3	3	4	4	4	4	4	1	1
	CPP-Small	2	2	2	2	2	3	3	3	3	2	2	2
	DBP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**15**	**15**	**15**	**63**	**85**	**107**	**138**	**167**	**136**	**111**	**35**	**14**
Demand Response Aggregator-managed	CBP-DA	3	3	3	3	3	4	5	5	6	6	3	3
	CBP-DO	37	38	37	40	35	43	43	45	51	49	36	36
	AMP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**40**	**42**	**40**	**43**	**38**	**47**	**48**	**50**	**56**	**54**	**40**	**39**
SmartConnect®-enabled	SPD with Tech.	3	3	-6	37	42	47	55	64	56	55	0	3
	SUB-TOTAL	**3**	**3**	**-6**	**37**	**42**	**47**	**55**	**64**	**56**	**55**	**0**	**3**
Nonevent Based	RTP	0	0	0	0	0	-1	-1	1	-1	0	0	0
	PLS	0	0	0	0	6	6	6	7	7	6	0	0
	SUB-TOTAL	**0**	**0**	**0**	**0**	**6**	**4**	**5**	**7**	**5**	**6**	**0**	**0**
PORTFOLIO TOTAL		**592**	**613**	**603**	**729**	**803**	**842**	**879**	**939**	**874**	**856**	**646**	**591**

Appendix D Portfolio Aggregate Ex Ante Load Impact Estimates for 1-in-10 SCE-specific System Conditions by Month and Forecast Year

Table D-1: 2017 Portfolio Aggregate Ex Ante Load Impact Estimates for 1-in-10 SCE-specific System Conditions

Program Type	Program	Monthly System Peak											
		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Emergency	BIP-15	106	117	132	123	137	147	149	149	149	149	143	121
	BIP-30	435	433	434	473	515	506	495	518	499	506	460	435
	AP-I	24	25	34	48	54	55	53	53	43	42	33	25
	SUB-TOTAL	**565**	**575**	**600**	**645**	**706**	**708**	**697**	**720**	**691**	**697**	**636**	**581**
Price-responsive	SDP-C	7	9	14	29	34	32	35	40	41	34	20	7
	SDP-R	0	0	6	126	183	189	231	256	245	168	97	0
	CPP-Large	8	8	8	18	17	16	15	16	17	18	9	8
	CPP-Medium	0	0	0	0	0	0	0	0	0	0	0	0
	CPP-Small	0	0	0	0	0	0	0	0	0	0	0	0
	DBP	4	4	4	5	5	5	5	6	6	5	5	4
	SUB-TOTAL	**19**	**21**	**33**	**178**	**240**	**242**	**287**	**317**	**309**	**225**	**131**	**20**
Demand Response Aggregator-managed	CBP-DA	1	1	1	1	1	1	2	2	2	2	1	1
	CBP-DO	24	25	25	26	23	28	28	29	33	32	24	23
	AMP	83	82	82	82	80	78	77	79	77	77	83	83
	SUB-TOTAL	**108**	**108**	**109**	**109**	**104**	**107**	**107**	**110**	**112**	**111**	**108**	**108**
SmartConnect®-enabled	SPD with Tech.	1	1	0	8	10	10	11	12	13	11	1	1
	SUB-TOTAL	**1**	**1**	**0**	**8**	**10**	**10**	**11**	**12**	**13**	**11**	**1**	**1**
Nonevent Based	RTP	0	0	0	2	0	-1	4	1	6	2	1	0
	PLS	0*	0*	0*	0*	0*	0*	0*	0*	0*	0*	0*	0*
	SUB-TOTAL	**0**	**0**	**0**	**2**	**0**	**-1**	**4**	**1**	**6**	**2**	**1**	**0**
PORTFOLIO TOTAL		**693**	**706**	**741**	**942**	**1,059**	**1,065**	**1,106**	**1,160**	**1,130**	**1,046**	**878**	**709**

*Load impacts are redacted to protect confidential customer information

Table D-2: 2018 Portfolio Aggregate Ex Ante Load Impact Estimates for 1-in-10 SCE-specific System Conditions

Program Type	Program	Monthly System Peak											
		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Emergency	BIP-15	123	134	140	129	139	147	149	148	148	148	142	120
	BIP-30	435	433	432	470	509	499	488	508	490	498	451	427
	AP-I	24	26	34	49	55	55	53	54	43	42	33	25
	SUB-TOTAL	**582**	**593**	**606**	**648**	**703**	**702**	**690**	**710**	**681**	**688**	**626**	**572**
Price-responsive	SDP-C	7	9	13	27	32	29	32	37	38	31	19	7
	SDP-R	0	0	6	119	174	179	220	243	233	159	93	0
	CPP-Large	8	8	8	18	17	16	15	16	17	18	9	8
	CPP-Medium	0	0	0	0	0	0	0	0	0	4	2	1
	CPP-Small	0	0	0	0	0	0	0	0	0	1	0	0
	DBP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**14**	**16**	**27**	**165**	**223**	**225**	**268**	**296**	**288**	**213**	**122**	**16**
Demand Response Aggregator-managed	CBP-DA	3	3	3	3	3	4	5	5	6	6	3	3
	CBP-DO	37	38	39	40	35	43	43	45	51	49	36	36
	AMP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**40**	**42**	**42**	**43**	**38**	**47**	**48**	**50**	**56**	**54**	**40**	**39**
SmartConnect®-enabled	SPD with Tech.	1	1	0	15	17	17	19	21	22	19	2	1
	SUB-TOTAL	**1**	**1**	**0**	**15**	**17**	**17**	**19**	**21**	**22**	**19**	**2**	**1**
Nonevent Based	RTP	0	0	0	2	0	-1	4	1	6	2	1	0
	PLS	0	0	0	0	4	4	4	4	5	4	0	0
	SUB-TOTAL	**0**	**0**	**0**	**2**	**4**	**2**	**8**	**5**	**10**	**6**	**1**	**0**
PORTFOLIO TOTAL		**638**	**652**	**675**	**872**	**985**	**993**	**1,032**	**1,081**	**1,057**	**979**	**791**	**629**

Table D-3: 2019 Portfolio Aggregate Ex Ante Load Impact Estimates for 1-in-10 SCE-specific System Conditions

Program Type	Program	Monthly System Peak											
		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Emergency	BIP-15	122	133	139	128	138	147	149	146	147	147	140	119
	BIP-30	426	424	424	460	497	487	476	496	478	485	440	416
	AP-I	24	26	35	49	55	56	53	54	43	42	33	25
	SUB-TOTAL	**573**	**583**	**597**	**637**	**690**	**690**	**678**	**697**	**668**	**674**	**614**	**561**
Price-responsive	SDP-C	6	8	12	25	30	27	30	34	35	29	17	6
	SDP-R	0	0	6	114	165	171	209	231	221	152	88	0
	CPP-Large	8	8	8	18	17	16	15	16	17	18	9	8
	CPP-Medium	1	1	1	4	4	4	4	4	4	9	4	3
	CPP-Small	0	0	0	1	1	1	1	1	1	6	5	4
	DBP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**15**	**17**	**28**	**161**	**217**	**219**	**259**	**287**	**279**	**214**	**123**	**22**
Demand Response Aggregator-managed	CBP-DA	3	3	3	3	3	4	5	5	6	6	3	3
	CBP-DO	37	38	39	40	35	43	43	45	51	49	36	36
	AMP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**40**	**42**	**42**	**43**	**38**	**47**	**48**	**50**	**56**	**54**	**40**	**39**
SmartConnect®-enabled	SPD with Tech.	2	2	0	19	22	21	24	26	27	23	2	2
	SUB-TOTAL	**2**	**2**	**0**	**19**	**22**	**21**	**24**	**26**	**27**	**23**	**2**	**2**
Nonevent Based	RTP	0	0	0	2	0	-1	4	1	6	2	1	0
	PLS	0	0	0	0	5	5	6	6	6	5	0	0
	SUB-TOTAL	**0**	**0**	**0**	**2**	**5**	**4**	**9**	**6**	**12**	**7**	**1**	**0**
PORTFOLIO TOTAL		**630**	**644**	**666**	**862**	**971**	**980**	**1,018**	**1,065**	**1,042**	**973**	**779**	**623**

Table D-4: 2020 Portfolio Aggregate Ex Ante Load Impact Estimates for 1-in-10 SCE-specific System Conditions

Program Type	Program	Monthly System Peak											
		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Emergency	BIP-15	121	132	138	127	137	146	148	145	145	146	136	115
	BIP-30	416	412	413	450	487	479	467	486	468	475	431	408
	AP-I	24	26	35	49	55	55	53	54	43	42	33	25
	SUB-TOTAL	**562**	**571**	**585**	**626**	**679**	**680**	**668**	**685**	**657**	**663**	**600**	**548**
Price-responsive	SDP-C	6	7	11	23	27	25	28	32	33	27	16	6
	SDP-R	0	0	5	108	157	162	199	220	211	144	84	0
	CPP-Large	8	8	8	18	17	16	15	16	17	18	9	8
	CPP-Medium	3	3	3	9	10	10	10	11	11	4	2	1
	CPP-Small	4	4	4	6	6	7	7	8	8	3	2	2
	DBP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**21**	**22**	**32**	**164**	**218**	**220**	**260**	**286**	**278**	**195**	**112**	**17**
Demand Response Aggregator-managed	CBP-DA	3	3	3	3	3	4	5	5	6	6	3	3
	CBP-DO	37	38	39	40	35	43	43	45	51	49	36	36
	AMP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**40**	**42**	**42**	**43**	**38**	**47**	**48**	**50**	**56**	**54**	**40**	**39**
SmartConnect®-enabled	SPD with Tech.	2	2	-1	23	27	26	29	31	32	28	2	2
	SUB-TOTAL	**2**	**2**	**-1**	**23**	**27**	**26**	**29**	**31**	**32**	**28**	**2**	**2**
Nonevent Based	RTP	0	0	0	2	0	-1	4	1	6	2	1	0
	PLS	0	0	0	0	5	6	6	6	6	6	0	0
	SUB-TOTAL	**0**	**0**	**0**	**2**	**5**	**4**	**10**	**7**	**12**	**7**	**1**	**0**
PORTFOLIO TOTAL		**625**	**637**	**659**	**858**	**967**	**977**	**1,014**	**1,059**	**1,036**	**948**	**755**	**606**

Table D-5: 2021 Portfolio Aggregate Ex Ante Load Impact Estimates for 1-in-10 SCE-specific System Conditions

Program Type	Program	Monthly System Peak											
		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Emergency	BIP-15	117	128	133	123	132	141	143	140	141	140	134	113
	BIP-30	407	405	406	440	479	469	458	477	460	466	423	401
	AP-I	24	26	34	49	54	55	52	53	42	41	32	25
	SUB-TOTAL	**548**	**559**	**573**	**612**	**665**	**665**	**653**	**670**	**643**	**647**	**589**	**539**
Price-responsive	SDP-C	5	7	10	21	25	23	25	29	30	24	15	5
	SDP-R	0	0	5	103	150	154	189	209	200	137	80	0
	CPP-Large	8	8	8	18	17	16	15	16	17	18	9	8
	CPP-Medium	1	1	1	4	4	4	4	4	4	4	2	1
	CPP-Small	2	2	2	2	3	3	3	3	3	3	2	2
	DBP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**16**	**18**	**27**	**148**	**198**	**200**	**237**	**262**	**254**	**186**	**107**	**16**
Demand Response Aggregator-managed	CBP-DA	3	3	3	3	3	4	5	5	6	6	3	3
	CBP-DO	37	38	39	40	35	43	43	45	51	49	36	36
	AMP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**40**	**42**	**42**	**43**	**38**	**47**	**48**	**50**	**56**	**54**	**40**	**39**
SmartConnect®-enabled	SPD with Tech.	2	2	-1	27	31	30	34	37	38	32	3	3
	SUB-TOTAL	**2**	**2**	**-1**	**27**	**31**	**30**	**34**	**37**	**38**	**32**	**3**	**3**
Nonevent Based	RTP	0	0	0	2	0	-1	4	1	6	2	1	0
	PLS	0	0	0	0	6	6	7	7	7	6	0	0
	SUB-TOTAL	**0**	**0**	**0**	**2**	**6**	**5**	**10**	**7**	**13**	**8**	**1**	**0**
PORTFOLIO TOTAL		**606**	**620**	**641**	**832**	**938**	**947**	**982**	**1,026**	**1,004**	**927**	**739**	**597**

Table D-6: 2022 Portfolio Aggregate Ex Ante Load Impact Estimates for 1-in-10 SCE-specific System Conditions

Program Type	Program	Monthly System Peak											
		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Emergency	BIP-15	116	127	132	121	131	139	141	140	140	140	134	113
	BIP-30	400	398	398	431	469	461	449	468	452	459	418	396
	AP-I	24	25	34	48	53	54	51	52	42	41	32	24
	SUB-TOTAL	**539**	**550**	**563**	**600**	**653**	**654**	**641**	**660**	**634**	**640**	**583**	**533**
Price-responsive	SDP-C	5	6	9	20	23	21	23	27	28	22	13	5
	SDP-R	0	0	5	98	142	146	180	198	190	130	76	0
	CPP-Large	8	8	8	18	17	16	15	16	17	18	9	8
	CPP-Medium	1	1	1	4	4	4	4	4	4	4	2	1
	CPP-Small	2	2	2	2	3	3	3	3	3	3	2	2
	DBP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**15**	**17**	**26**	**141**	**189**	**191**	**226**	**249**	**242**	**177**	**101**	**16**
Demand Response Aggregator-managed	CBP-DA	3	3	3	3	3	4	5	5	6	6	3	3
	CBP-DO	37	38	39	40	35	43	43	45	51	49	36	36
	AMP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**40**	**42**	**42**	**43**	**38**	**47**	**48**	**50**	**56**	**54**	**40**	**39**
SmartConnect®-enabled	SPD with Tech.	3	3	-1	31	36	35	39	42	43	37	3	3
	SUB-TOTAL	**3**	**3**	**-1**	**31**	**36**	**35**	**39**	**42**	**43**	**37**	**3**	**3**
Nonevent Based	RTP	0	0	0	2	0	-1	4	1	6	2	1	0
	PLS	0	0	0	0	6	6	7	7	7	6	0	0
	SUB-TOTAL	**0**	**0**	**0**	**2**	**6**	**5**	**11**	**8**	**13**	**8**	**1**	**0**
PORTFOLIO TOTAL		**597**	**611**	**630**	**818**	**922**	**931**	**964**	**1,008**	**989**	**917**	**729**	**591**

Table D-7: 2023 Portfolio Aggregate Ex Ante Load Impact Estimates for 1-in-10 SCE-specific System Conditions

Program Type	Program	Monthly System Peak											
		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Emergency	BIP-15	116	127	132	121	131	139	141	140	140	140	134	113
	BIP-30	396	394	395	429	467	459	449	468	452	459	418	396
	AP-I	23	25	33	48	53	54	51	52	42	41	32	24
	SUB-TOTAL	**535**	**546**	**560**	**598**	**651**	**652**	**641**	**660**	**634**	**640**	**583**	**533**
Price-responsive	SDP-C	4	6	9	18	21	19	22	25	25	21	12	5
	SDP-R	0	0	5	93	135	139	171	188	181	124	72	0
	CPP-Large	8	8	8	18	17	16	15	16	17	18	9	8
	CPP-Medium	1	1	1	4	4	4	4	4	4	4	2	1
	CPP-Small	2	2	2	2	3	3	3	3	3	3	2	2
	DBP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**15**	**17**	**25**	**135**	**180**	**182**	**215**	**237**	**230**	**169**	**97**	**15**
Demand Response Aggregator-managed	CBP-DA	3	3	3	3	3	4	5	5	6	6	3	3
	CBP-DO	37	38	39	40	35	43	43	45	51	49	36	36
	AMP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**40**	**42**	**42**	**43**	**38**	**47**	**48**	**50**	**56**	**54**	**40**	**39**
SmartConnect®-enabled	SPD with Tech.	3	3	-1	35	41	39	44	47	49	41	3	3
	SUB-TOTAL	**3**	**3**	**-1**	**35**	**41**	**39**	**44**	**47**	**49**	**41**	**3**	**3**
Nonevent Based	RTP	0	0	0	2	0	-1	4	1	6	2	1	0
	PLS	0	0	0	0	6	7	7	8	8	7	0	0
	SUB-TOTAL	**0**	**0**	**0**	**2**	**7**	**5**	**11**	**8**	**14**	**9**	**1**	**0**
PORTFOLIO TOTAL		**593**	**607**	**626**	**814**	**916**	**925**	**959**	**1,002**	**983**	**913**	**724**	**591**

Table D-8: 2024 Portfolio Aggregate Ex Ante Load Impact Estimates for 1-in-10 SCE-specific System Conditions

Program Type	Program	Monthly System Peak											
		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Emergency	BIP-15	116	127	132	121	131	139	141	140	140	140	134	113
	BIP-30	396	394	395	429	467	459	449	468	452	459	418	396
	AP-I	23	25	33	48	53	54	51	52	42	41	32	24
	SUB-TOTAL	**535**	**546**	**560**	**598**	**651**	**652**	**641**	**660**	**634**	**640**	**583**	**533**
Price-responsive	SDP-C	4	5	8	17	19	18	20	23	23	19	11	4
	SDP-R	0	0	4	88	128	132	162	179	172	117	68	0
	CPP-Large	8	8	8	18	17	16	15	16	17	18	9	8
	CPP-Medium	1	1	1	4	4	4	4	4	4	4	2	1
	CPP-Small	2	2	2	2	3	3	3	3	3	3	2	2
	DBP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**15**	**16**	**24**	**129**	**171**	**173**	**204**	**225**	**219**	**161**	**92**	**15**
Demand Response Aggregator-managed	CBP-DA	3	3	3	3	3	4	5	5	6	6	3	3
	CBP-DO	37	38	39	40	35	43	43	45	51	49	36	36
	AMP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**40**	**42**	**42**	**43**	**38**	**47**	**48**	**50**	**56**	**54**	**40**	**39**
SmartConnect®-enabled	SPD with Tech.	3	3	-1	40	45	43	49	53	54	46	4	4
	SUB-TOTAL	**3**	**3**	**-1**	**40**	**45**	**43**	**49**	**53**	**54**	**46**	**4**	**4**
Nonevent Based	RTP	0	0	0	2	0	-1	4	1	6	2	1	0
	PLS	0	0	0	0	6	7	7	8	8	7	0	0
	SUB-TOTAL	**0**	**0**	**0**	**2**	**7**	**5**	**11**	**8**	**14**	**9**	**1**	**0**
PORTFOLIO TOTAL		**593**	**607**	**625**	**812**	**912**	**921**	**953**	**996**	**977**	**910**	**720**	**591**

Table D-9: 2025 Portfolio Aggregate Ex Ante Load Impact Estimates for 1-in-10 SCE-specific System Conditions

Program Type	Program	Monthly System Peak											
		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Emergency	BIP-15	116	127	132	121	131	139	141	140	140	140	134	113
	BIP-30	396	394	395	429	467	459	449	468	452	459	418	396
	AP-I	23	25	33	48	53	54	51	52	42	41	32	24
	SUB-TOTAL	**535**	**546**	**560**	**598**	**651**	**652**	**641**	**660**	**634**	**640**	**583**	**533**
Price-responsive	SDP-C	4	5	7	15	18	16	18	21	21	17	10	4
	SDP-R	0	0	4	84	122	125	154	170	163	111	65	0
	CPP-Large	8	8	8	18	17	16	16	16	17	18	9	8
	CPP-Medium	1	1	1	4	4	4	4	4	4	4	2	1
	CPP-Small	2	2	2	2	3	3	3	3	3	3	2	2
	DBP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**14**	**16**	**23**	**123**	**163**	**165**	**195**	**214**	**208**	**153**	**88**	**15**
Demand Response Aggregator-managed	CBP-DA	3	3	3	3	3	4	5	5	6	6	3	3
	CBP-DO	37	38	39	40	35	43	43	45	51	49	36	36
	AMP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**40**	**42**	**42**	**43**	**38**	**47**	**48**	**50**	**56**	**54**	**40**	**39**
SmartConnect®-enabled	SPD with Tech.	4	4	-1	44	50	48	54	58	60	50	4	4
	SUB-TOTAL	**4**	**4**	**-1**	**44**	**50**	**48**	**54**	**58**	**60**	**50**	**4**	**4**
Nonevent Based	RTP	0	0	0	2	0	-1	4	1	6	2	1	0
	PLS	0	0	0	0	6	7	7	8	8	7	0	0
	SUB-TOTAL	**0**	**0**	**0**	**2**	**6**	**5**	**11**	**8**	**13**	**8**	**1**	**0**
PORTFOLIO TOTAL		**593**	**607**	**624**	**810**	**908**	**917**	**948**	**990**	**971**	**907**	**716**	**591**

Table D-10: 2026 Portfolio Aggregate Ex Ante Load Impact Estimates for 1-in-10 SCE-specific System Conditions

Program Type	Program	Monthly System Peak											
		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Emergency	BIP-15	116	127	132	121	131	139	141	140	140	140	134	113
	BIP-30	396	394	395	429	467	459	449	468	452	459	418	396
	AP-I	23	25	33	48	53	54	51	52	42	41	32	24
	SUB-TOTAL	**535**	**546**	**560**	**598**	**651**	**652**	**641**	**660**	**634**	**640**	**583**	**533**
Price-responsive	SDP-C	3	4	7	14	16	15	16	19	19	16	9	4
	SDP-R	0	0	4	79	115	119	146	161	154	106	61	0
	CPP-Large	8	8	8	18	17	17	16	16	17	18	9	8
	CPP-Medium	1	1	1	4	4	4	4	4	4	4	2	1
	CPP-Small	2	2	2	2	3	3	3	3	3	3	2	2
	DBP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**14**	**15**	**22**	**117**	**155**	**157**	**185**	**204**	**198**	**146**	**83**	**14**
Demand Response Aggregator-managed	CBP-DA	3	3	3	3	3	4	5	5	6	6	3	3
	CBP-DO	37	38	39	40	35	43	43	45	51	49	36	36
	AMP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**40**	**42**	**42**	**43**	**38**	**47**	**48**	**50**	**56**	**54**	**40**	**39**
SmartConnect®-enabled	SPD with Tech.	4	4	-1	48	55	52	59	63	65	55	5	4
	SUB-TOTAL	**4**	**4**	**-1**	**48**	**55**	**52**	**59**	**63**	**65**	**55**	**5**	**4**
Nonevent Based	RTP	0	0	0	2	0	-1	4	1	6	2	1	0
	PLS	0	0	0	0	6	7	7	7	7	6	0	0
	SUB-TOTAL	**0**	**0**	**0**	**2**	**6**	**5**	**11**	**8**	**13**	**8**	**1**	**0**
PORTFOLIO TOTAL		**593**	**607**	**623**	**808**	**905**	**913**	**944**	**985**	**967**	**904**	**712**	**591**

Table D-11: 2027 Portfolio Aggregate Ex Ante Load Impact Estimates for 1-in-10 SCE-specific System Conditions

Program Type	Program	Monthly System Peak											
		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Emergency	BIP-15	116	127	132	121	131	139	141	140	140	140	134	113
	BIP-30	396	394	395	429	467	459	449	468	452	459	418	396
	AP-I	23	25	33	48	53	54	51	52	42	41	32	24
	SUB-TOTAL	**535**	**546**	**560**	**598**	**651**	**652**	**641**	**660**	**634**	**640**	**583**	**533**
Price-responsive	SDP-C	3	4	6	13	15	14	15	17	18	14	9	3
	SDP-R	0	0	4	75	109	113	138	153	146	100	58	0
	CPP-Large	8	8	8	18	17	17	16	16	17	18	9	8
	CPP-Medium	1	1	1	4	4	4	4	4	4	4	2	1
	CPP-Small	2	2	2	2	3	3	3	3	3	3	2	2
	DBP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**14**	**15**	**21**	**112**	**148**	**150**	**176**	**194**	**189**	**139**	**79**	**14**
Demand Response Aggregator-managed	CBP-DA	3	3	3	3	3	4	5	5	6	6	3	3
	CBP-DO	37	38	39	40	35	43	43	45	51	49	36	36
	AMP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**40**	**42**	**42**	**43**	**38**	**47**	**48**	**50**	**56**	**54**	**40**	**39**
SmartConnect®-enabled	SPD with Tech.	4	4	-1	52	59	57	64	69	70	59	5	5
	SUB-TOTAL	**4**	**4**	**-1**	**52**	**59**	**57**	**64**	**69**	**70**	**59**	**5**	**5**
Nonevent Based	RTP	0	0	0	2	0	-1	4	1	6	2	1	0
	PLS	0	0	0	0	6	6	7	7	7	6	0	0
	SUB-TOTAL	**0**	**0**	**0**	**2**	**6**	**5**	**10**	**8**	**13**	**8**	**1**	**0**
PORTFOLIO TOTAL		**593**	**607**	**622**	**807**	**902**	**910**	**940**	**980**	**962**	**901**	**709**	**592**

Appendix E Program-specific Aggregate Ex Ante Load Impact Estimates for 1-in-2 SCE-specific System Conditions by Month and Forecast Year

Table E-1: 2017 Program-specific Aggregate Ex Ante Load Impact Estimates for 1-in-2 SCE-specific System Conditions

Program Type	Program	Monthly System Peak											
		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Emergency	BIP-15	109	121	129	120	136	147	148	149	149	150	142	123
	BIP-30	432	437	433	469	502	490	489	511	486	500	453	433
	AP-I	22	25	31	43	49	53	52	50	40	37	28	26
	SUB-TOTAL	**563**	**583**	**593**	**631**	**687**	**691**	**689**	**710**	**675**	**687**	**623**	**581**
Price-responsive	SDP-C	9	10	10	21	23	25	29	36	32	30	15	8
	SDP-R	0	0	0	53	86	122	171	213	164	123	28	0
	CPP-Large	14	15	14	31	31	31	30	31	32	33	16	14
	CPP-Medium	0	0	0	0	0	0	0	0	0	0	0	0
	CPP-Small	0	0	0	0	0	0	0	0	0	0	0	0
	DBP	51	51	52	52	61	101	101	103	99	62	59	48
	SUB-TOTAL	**75**	**75**	**76**	**157**	**203**	**280**	**330**	**382**	**327**	**248**	**118**	**70**
Demand Response Aggregator-managed	CBP-DA	1	1	1	1	1	1	2	2	2	2	1	1
	CBP-DO	24	25	24	26	23	28	28	29	33	32	24	23
	AMP	82	82	82	82	80	78	77	79	77	77	83	83
	SUB-TOTAL	**107**	**108**	**107**	**109**	**104**	**107**	**107**	**110**	**112**	**111**	**108**	**108**
SmartConnect®-enabled	SPD with Tech.	1	1	-1	7	8	10	12	14	13	13	0	1
	SUB-TOTAL	**1**	**1**	**-1**	**7**	**8**	**10**	**12**	**14**	**13**	**13**	**0**	**1**
Nonevent Based	RTP	1	1	1	0	0	-7	-7	2	-7	0	1	1
	PLS	0*	0*	0*	0*	0*	0*	0*	0*	0*	0*	0*	0*
	SUB-TOTAL	**1**	**1**	**1**	**0**	**0**	**-7**	**-7**	**2**	**-7**	**0**	**1**	**1**
PORTFOLIO TOTAL		**746**	**768**	**775**	**904**	**1,002**	**1,081**	**1,131**	**1,218**	**1,120**	**1,058**	**850**	**760**

*Load impacts are redacted to protect confidential customer information

Table E-2: 2018 Program-specific Aggregate Ex Ante Load Impact Estimates for 1-in-2 SCE-specific System Condition

Program Type	Program	Monthly System Peak											
		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Emergency	BIP-15	126	139	136	126	138	147	148	148	148	149	141	122
	BIP-30	433	436	430	465	496	484	482	501	477	491	445	425
	AP-I	22	26	32	44	50	54	52	50	41	38	28	26
	SUB-TOTAL	**581**	**601**	**598**	**635**	**684**	**685**	**683**	**699**	**665**	**678**	**613**	**572**
Price-responsive	SDP-C	8	9	10	19	22	24	27	34	30	27	14	7
	SDP-R	0	0	0	50	82	116	162	202	155	117	27	0
	CPP-Large	14	15	14	31	31	31	30	31	32	33	16	14
	CPP-Medium	0	0	0	0	0	0	0	0	0	4	1	1
	CPP-Small	0	0	0	0	0	0	0	0	0	1	0	0
	DBP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**23**	**24**	**24**	**100**	**135**	**170**	**219**	**267**	**218**	**182**	**58**	**23**
Demand Response Aggregator-managed	CBP-DA	3	3	3	3	3	4	5	5	6	6	3	3
	CBP-DO	37	38	37	40	35	43	43	45	51	49	36	36
	AMP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**40**	**42**	**40**	**43**	**38**	**47**	**48**	**50**	**56**	**54**	**40**	**39**
SmartConnect®-enabled	SPD with Tech.	1	1	-2	11	12	14	16	19	17	17	0	1
	SUB-TOTAL	**1**	**1**	**-2**	**11**	**12**	**14**	**16**	**19**	**17**	**17**	**0**	**1**
Nonevent Based	RTP	1	1	1	0	0	-7	-7	2	-7	0	1	1
	PLS	0	0	0	0	3	3	4	4	4	4	0	0
	SUB-TOTAL	**1**	**1**	**1**	**0**	**4**	**-3**	**-3**	**7**	**-2**	**4**	**1**	**1**
PORTFOLIO TOTAL		**645**	**668**	**661**	**789**	**873**	**913**	**963**	**1,042**	**954**	**935**	**712**	**637**

Table E-3: 2019 Program-specific Aggregate Ex Ante Load Impact Estimates for 1-in-2 SCE-specific System Conditions

Program Type	Program	Monthly System Peak											
		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Emergency	BIP-15	125	138	135	125	137	147	148	146	147	147	139	121
	BIP-30	424	427	422	455	484	472	469	489	465	478	434	414
	AP-I	22	26	32	44	50	54	53	51	41	38	28	26
	SUB-TOTAL	**571**	**591**	**590**	**624**	**671**	**674**	**671**	**686**	**653**	**664**	**601**	**561**
Price-responsive	SDP-C	8	9	9	18	20	22	25	31	28	25	13	7
	SDP-R	0	0	0	47	78	110	154	192	148	111	25	0
	CPP-Large	14	15	14	31	31	31	30	31	32	33	16	14
	CPP-Medium	1	1	1	3	3	4	4	4	4	9	4	3
	CPP-Small	0	0	0	1	1	1	1	1	1	6	4	4
	DBP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**24**	**25**	**25**	**100**	**134**	**167**	**214**	**259**	**212**	**185**	**62**	**28**
Demand Response Aggregator-managed	CBP-DA	3	3	3	3	3	4	5	5	6	6	3	3
	CBP-DO	37	38	37	40	35	43	43	45	51	49	36	36
	AMP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**40**	**42**	**40**	**43**	**38**	**47**	**48**	**50**	**56**	**54**	**40**	**39**
SmartConnect®-enabled	SPD with Tech.	1	1	-2	14	16	18	21	24	22	21	0	1
	SUB-TOTAL	**1**	**1**	**-2**	**14**	**16**	**18**	**21**	**24**	**22**	**21**	**0**	**1**
Nonevent Based	RTP	1	1	1	0	0	-7	-7	2	-7	0	1	1
	PLS	0	0	0	0	5	5	5	6	6	5	0	0
	SUB-TOTAL	**1**	**1**	**1**	**0**	**5**	**-2**	**-1**	**8**	**-1**	**5**	**1**	**1**
PORTFOLIO TOTAL		**637**	**659**	**653**	**782**	**863**	**904**	**951**	**1,028**	**942**	**930**	**703**	**631**

Table E-4: 2020 Program-specific Aggregate Ex Ante Load Impact Estimates for 1-in-2 SCE-specific System Conditions

Program Type	Program	Monthly System Peak											
		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Emergency	BIP-15	124	137	134	124	136	146	147	145	146	146	135	116
	BIP-30	414	415	412	445	474	464	461	479	456	469	425	406
	AP-I	22	26	32	44	50	54	52	50	40	38	28	26
	SUB-TOTAL	**560**	**578**	**578**	**613**	**660**	**664**	**661**	**675**	**642**	**653**	**587**	**548**
Price-responsive	SDP-C	7	8	8	16	19	20	23	29	25	23	12	6
	SDP-R	0	0	0	45	74	105	147	183	141	106	24	0
	CPP-Large	14	15	14	31	31	31	30	31	33	34	16	14
	CPP-Medium	3	3	3	8	8	9	10	11	10	4	1	1
	CPP-Small	4	4	4	5	5	6	7	8	7	2	2	2
	DBP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**29**	**30**	**30**	**106**	**138**	**171**	**216**	**261**	**215**	**169**	**55**	**23**
Demand Response Aggregator-managed	CBP-DA	3	3	3	3	3	4	5	5	6	6	3	3
	CBP-DO	37	38	37	40	35	43	43	45	51	49	36	36
	AMP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**40**	**42**	**40**	**43**	**38**	**47**	**48**	**50**	**56**	**54**	**40**	**39**
SmartConnect®-enabled	SPD with Tech.	1	1	-3	17	19	21	25	29	26	25	0	2
	SUB-TOTAL	**1**	**1**	**-3**	**17**	**19**	**21**	**25**	**29**	**26**	**25**	**0**	**2**
Nonevent Based	RTP	1	1	1	0	0	-7	-7	2	-7	0	1	1
	PLS	0	0	0	0	5	5	6	6	6	5	0	0
	SUB-TOTAL	**1**	**1**	**1**	**0**	**5**	**-2**	**-1**	**8**	**-1**	**6**	**1**	**1**
PORTFOLIO TOTAL		**631**	**652**	**646**	**779**	**860**	**902**	**949**	**1,023**	**938**	**907**	**682**	**613**

Table E-5: 2021 Program-specific Aggregate Ex Ante Load Impact Estimates for 1-in-2 SCE-specific System Conditions

Program Type	Program	Monthly System Peak											
		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Emergency	BIP-15	119	133	130	120	131	142	142	140	141	141	133	115
	BIP-30	405	408	404	436	466	455	452	470	447	460	417	399
	AP-I	22	26	31	44	49	53	52	50	40	37	27	25
	SUB-TOTAL	**546**	**566**	**566**	**599**	**646**	**649**	**646**	**660**	**628**	**637**	**577**	**539**
Price-responsive	SDP-C	7	7	7	15	17	18	21	26	23	22	11	6
	SDP-R	0	0	0	43	71	100	139	174	134	100	23	0
	CPP-Large	14	15	14	31	32	31	30	31	33	34	16	14
	CPP-Medium	1	1	1	3	3	4	4	4	4	4	1	1
	CPP-Small	2	2	2	2	2	3	3	3	3	2	2	2
	DBP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**24**	**25**	**25**	**95**	**125**	**155**	**197**	**239**	**196**	**162**	**53**	**23**
Demand Response Aggregator-managed	CBP-DA	3	3	3	3	3	4	5	5	6	6	3	3
	CBP-DO	37	38	37	40	35	43	43	45	51	49	36	36
	AMP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**40**	**42**	**40**	**43**	**38**	**47**	**48**	**50**	**56**	**54**	**40**	**39**
SmartConnect®-enabled	SPD with Tech.	2	2	-3	20	22	25	29	34	30	30	0	2
	SUB-TOTAL	**2**	**2**	**-3**	**20**	**22**	**25**	**29**	**34**	**30**	**30**	**0**	**2**
Nonevent Based	RTP	1	1	1	0	0	-7	-7	2	-7	0	1	1
	PLS	0	0	0	0	5	6	6	6	6	6	0	0
	SUB-TOTAL	**1**	**1**	**1**	**0**	**6**	**-1**	**0**	**9**	**0**	**6**	**1**	**1**
PORTFOLIO TOTAL		**613**	**635**	**629**	**756**	**837**	**876**	**919**	**992**	**911**	**889**	**670**	**604**

Table E-6: 2022 Program-specific Aggregate Ex Ante Load Impact Estimates for 1-in-2 SCE-specific System Conditions

Program Type	Program	Monthly System Peak											
		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Emergency	BIP-15	118	131	129	118	129	140	141	140	140	141	133	115
	BIP-30	397	401	397	427	457	447	443	462	440	453	411	394
	AP-I	22	25	31	43	49	52	51	49	39	36	27	25
	SUB-TOTAL	**537**	**557**	**556**	**587**	**635**	**639**	**634**	**650**	**620**	**630**	**571**	**534**
Price-responsive	SDP-C	6	7	7	14	16	17	19	24	21	20	10	5
	SDP-R	0	0	0	41	67	95	132	165	127	95	22	0
	CPP-Large	15	15	14	31	32	31	30	31	33	34	16	14
	CPP-Medium	1	1	1	3	3	4	4	4	4	4	1	1
	CPP-Small	2	2	2	2	2	3	3	3	3	2	2	2
	DBP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**24**	**24**	**24**	**91**	**120**	**149**	**189**	**228**	**188**	**155**	**51**	**23**
Demand Response Aggregator-managed	CBP-DA	3	3	3	3	3	4	5	5	6	6	3	3
	CBP-DO	37	38	37	40	35	43	43	45	51	49	36	36
	AMP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**40**	**42**	**40**	**43**	**38**	**47**	**48**	**50**	**56**	**54**	**40**	**39**
SmartConnect®-enabled	SPD with Tech.	2	2	-4	23	26	29	33	39	35	34	0	2
	SUB-TOTAL	**2**	**2**	**-4**	**23**	**26**	**29**	**33**	**39**	**35**	**34**	**0**	**2**
Nonevent Based	RTP	1	1	1	0	0	-7	-7	2	-7	0	1	1
	PLS	0	0	0	0	6	6	7	7	7	6	0	0
	SUB-TOTAL	**1**	**1**	**1**	**0**	**6**	**-1**	**0**	**9**	**0**	**6**	**1**	**1**
PORTFOLIO TOTAL		**604**	**626**	**618**	**745**	**824**	**863**	**904**	**977**	**899**	**880**	**662**	**598**

Table E-7: 2023 Program-specific Aggregate Ex Ante Load Impact Estimates for 1-in-2 SCE-specific System Conditions

Program Type	Program	Monthly System Peak											
		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Emergency	BIP-15	118	131	129	118	129	140	141	140	140	141	133	115
	BIP-30	394	397	393	425	455	445	443	462	440	453	411	394
	AP-I	22	25	31	43	48	52	51	49	39	36	27	25
	SUB-TOTAL	**533**	**553**	**553**	**586**	**633**	**637**	**634**	**650**	**620**	**630**	**571**	**534**
Price-responsive	SDP-C	6	6	6	13	14	16	18	22	20	18	9	5
	SDP-R	0	0	0	39	64	90	126	157	121	91	21	0
	CPP-Large	15	15	14	31	32	31	30	31	33	34	16	14
	CPP-Medium	1	1	1	3	3	4	4	4	4	4	1	1
	CPP-Small	2	2	2	2	2	3	3	3	3	2	2	2
	DBP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**23**	**24**	**24**	**88**	**116**	**143**	**181**	**218**	**180**	**149**	**49**	**22**
Demand Response Aggregator-managed	CBP-DA	3	3	3	3	3	4	5	5	6	6	3	3
	CBP-DO	37	38	37	40	35	43	43	45	51	49	36	36
	AMP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**40**	**42**	**40**	**43**	**38**	**47**	**48**	**50**	**56**	**54**	**40**	**39**
SmartConnect®-enabled	SPD with Tech.	2	2	-4	25	29	32	38	44	39	38	0	2
	SUB-TOTAL	**2**	**2**	**-4**	**25**	**29**	**32**	**38**	**44**	**39**	**38**	**0**	**2**
Nonevent Based	RTP	1	1	1	0	0	-7	-7	2	-7	0	1	1
	PLS	0	0	0	0	6	6	7	7	7	6	0	0
	SUB-TOTAL	**1**	**1**	**1**	**0**	**6**	**0**	**0**	**10**	**0**	**7**	**1**	**1**
PORTFOLIO TOTAL		**599**	**621**	**613**	**743**	**821**	**859**	**900**	**972**	**895**	**878**	**661**	**598**

Table E-8: 2024 Program-specific Aggregate Ex Ante Load Impact Estimates for 1-in-2 SCE-specific System Conditions

Program Type	Program	Monthly System Peak											
		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Emergency	BIP-15	118	131	129	118	129	140	141	140	140	141	133	115
	BIP-30	394	397	393	425	455	445	443	462	440	453	411	394
	AP-I	22	25	31	43	48	52	51	49	39	36	27	25
	SUB-TOTAL	**533**	**553**	**553**	**586**	**633**	**637**	**634**	**650**	**620**	**630**	**571**	**534**
Price-responsive	SDP-C	5	6	6	12	13	14	16	20	18	17	9	4
	SDP-R	0	0	0	37	61	85	119	149	115	86	20	0
	CPP-Large	15	15	14	32	32	31	30	31	33	34	16	14
	CPP-Medium	1	1	1	3	3	4	4	4	4	4	1	1
	CPP-Small	2	2	2	2	2	3	3	3	3	2	2	2
	DBP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**23**	**23**	**23**	**85**	**111**	**137**	**173**	**208**	**172**	**143**	**47**	**22**
Demand Response Aggregator-managed	CBP-DA	3	3	3	3	3	4	5	5	6	6	3	3
	CBP-DO	37	38	37	40	35	43	43	45	51	49	36	36
	AMP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**40**	**42**	**40**	**43**	**38**	**47**	**48**	**50**	**56**	**54**	**40**	**39**
SmartConnect®-enabled	SPD with Tech.	2	2	-4	28	32	36	42	49	43	42	0	3
	SUB-TOTAL	**2**	**2**	**-4**	**28**	**32**	**36**	**42**	**49**	**43**	**42**	**0**	**3**
Nonevent Based	RTP	1	1	1	0	0	-7	-7	2	-7	0	1	1
	PLS	0	0	0	0	6	6	7	7	7	6	0	0
	SUB-TOTAL	**1**	**1**	**1**	**0**	**6**	**0**	**0**	**10**	**1**	**7**	**1**	**1**
PORTFOLIO TOTAL		**599**	**621**	**612**	**743**	**820**	**857**	**897**	**967**	**892**	**876**	**659**	**598**

Table E-9: 2025 Program-specific Aggregate Ex Ante Load Impact Estimates for 1-in-2 SCE-specific System Conditions

Program Type	Program	Monthly System Peak											
		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Emergency	BIP-15	118	131	129	118	129	140	141	140	140	141	133	115
	BIP-30	394	397	393	425	455	445	443	462	440	453	411	394
	AP-I	22	25	31	43	48	52	51	49	39	36	27	25
	SUB-TOTAL	**533**	**553**	**553**	**586**	**633**	**637**	**634**	**650**	**620**	**630**	**571**	**534**
Price-responsive	SDP-C	5	5	5	11	12	13	15	19	17	15	8	4
	SDP-R	0	0	0	35	57	81	113	141	109	82	19	0
	CPP-Large	15	15	15	32	32	31	30	32	33	34	16	14
	CPP-Medium	1	1	1	3	3	4	4	4	4	4	1	1
	CPP-Small	2	2	2	2	2	3	3	3	3	2	2	2
	DBP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**22**	**23**	**23**	**83**	**107**	**132**	**165**	**199**	**165**	**137**	**46**	**21**
Demand Response Aggregator-managed	CBP-DA	3	3	3	3	3	4	5	5	6	6	3	3
	CBP-DO	37	38	37	40	35	43	43	45	51	49	36	36
	AMP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**40**	**42**	**40**	**43**	**38**	**47**	**48**	**50**	**56**	**54**	**40**	**39**
SmartConnect®-enabled	SPD with Tech.	3	3	-5	31	35	40	46	54	48	46	0	3
	SUB-TOTAL	**3**	**3**	**-5**	**31**	**35**	**40**	**46**	**54**	**48**	**46**	**0**	**3**
Nonevent Based	RTP	1	1	1	0	0	-7	-7	2	-7	0	1	1
	PLS	0	0	0	0	6	6	7	7	7	6	0	0
	SUB-TOTAL	**1**	**1**	**1**	**0**	**6**	**-1**	**0**	**10**	**0**	**6**	**1**	**1**
PORTFOLIO TOTAL		**599**	**621**	**611**	**743**	**819**	**855**	**894**	**963**	**889**	**874**	**657**	**598**

Table E-10: 2026 Program-specific Aggregate Ex Ante Load Impact Estimates for 1-in-2 SCE-specific System Conditions

Program Type	Program	Monthly System Peak											
		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Emergency	BIP-15	118	131	129	118	129	140	141	140	140	141	133	115
	BIP-30	394	397	393	425	455	445	443	462	440	453	411	394
	AP-I	22	25	31	43	48	52	51	49	39	36	27	25
	SUB-TOTAL	**533**	**553**	**553**	**586**	**633**	**637**	**634**	**650**	**620**	**630**	**571**	**534**
Price-responsive	SDP-C	4	5	5	10	11	12	14	17	15	14	7	4
	SDP-R	0	0	0	33	54	77	107	134	103	77	18	0
	CPP-Large	15	15	15	32	32	32	30	32	33	34	16	15
	CPP-Medium	1	1	1	3	3	4	4	4	4	4	1	1
	CPP-Small	2	2	2	2	2	3	3	3	3	2	2	2
	DBP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**22**	**23**	**22**	**80**	**103**	**127**	**158**	**190**	**158**	**132**	**44**	**21**
Demand Response Aggregator-managed	CBP-DA	3	3	3	3	3	4	5	5	6	6	3	3
	CBP-DO	37	38	37	40	35	43	43	45	51	49	36	36
	AMP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**40**	**42**	**40**	**43**	**38**	**47**	**48**	**50**	**56**	**54**	**40**	**39**
SmartConnect®-enabled	SPD with Tech.	3	3	-5	34	39	44	51	59	52	50	0	3
	SUB-TOTAL	**3**	**3**	**-5**	**34**	**39**	**44**	**51**	**59**	**52**	**50**	**0**	**3**
Nonevent Based	RTP	1	1	1	0	0	-7	-7	2	-7	0	1	1
	PLS	0	0	0	0	6	6	7	7	7	6	0	0
	SUB-TOTAL	**1**	**1**	**1**	**0**	**6**	**-1**	**0**	**9**	**0**	**6**	**1**	**1**
PORTFOLIO TOTAL		**599**	**621**	**611**	**743**	**818**	**853**	**891**	**959**	**886**	**873**	**655**	**598**

Table E-11: 2027 Program-specific Aggregate Ex Ante Load Impact Estimates for 1-in-2 SCE-specific System Conditions

Program Type	Program	Monthly System Peak											
		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Emergency	BIP-15	118	131	129	118	129	140	141	140	140	141	133	115
	BIP-30	394	397	393	425	455	445	443	462	440	453	411	394
	AP-I	22	25	31	43	48	52	51	49	39	36	27	25
	SUB-TOTAL	**533**	**553**	**553**	**586**	**633**	**637**	**634**	**650**	**620**	**630**	**571**	**534**
Price-responsive	SDP-C	4	4	4	9	10	11	12	16	14	13	7	3
	SDP-R	0	0	0	31	52	73	102	127	98	73	17	0
	CPP-Large	15	15	15	32	32	32	31	32	33	34	16	15
	CPP-Medium	1	1	1	3	3	4	4	4	4	4	1	1
	CPP-Small	2	2	2	2	2	3	3	3	3	2	2	2
	DBP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**22**	**22**	**22**	**77**	**99**	**122**	**152**	**182**	**151**	**127**	**43**	**21**
Demand Response Aggregator-managed	CBP-DA	3	3	3	3	3	4	5	5	6	6	3	3
	CBP-DO	37	38	37	40	35	43	43	45	51	49	36	36
	AMP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**40**	**42**	**40**	**43**	**38**	**47**	**48**	**50**	**56**	**54**	**40**	**39**
SmartConnect®-enabled	SPD with Tech.	3	3	-6	37	42	47	55	64	56	55	0	3
	SUB-TOTAL	**3**	**3**	**-6**	**37**	**42**	**47**	**55**	**64**	**56**	**55**	**0**	**3**
Nonevent Based	RTP	1	1	1	0	0	-7	-7	2	-7	0	1	1
	PLS	0	0	0	0	6	6	6	7	7	6	0	0
	SUB-TOTAL	**1**	**1**	**1**	**0**	**6**	**-1**	**0**	**9**	**0**	**6**	**1**	**1**
PORTFOLIO TOTAL		**599**	**621**	**610**	**744**	**818**	**852**	**888**	**955**	**884**	**872**	**654**	**598**

Appendix F Program-specific Ex Ante Load Impact Estimates for 1-in-10 SCE-specific System Conditions by Month and Forecast Year

Table F-1: 2017 Program-specific Aggregate Ex Ante Load Impact Estimates for 1-in-10 SCE-specific System Conditions

Program Type	Program	Monthly System Peak											
		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Emergency	BIP-15	106	117	132	123	137	147	149	149	149	149	143	121
	BIP-30	435	433	434	473	515	506	495	518	499	506	460	435
	AP-I	24	25	34	48	54	55	53	53	43	42	33	25
	SUB-TOTAL	**565**	**575**	**600**	**645**	**706**	**708**	**697**	**720**	**691**	**697**	**636**	**581**
Price-responsive	SDP-C	7	9	14	29	34	32	35	40	41	34	20	7
	SDP-R	0	0	6	126	183	189	231	256	245	168	97	0
	CPP-Large	14	14	15	33	31	30	28	29	31	33	16	14
	CPP-Medium	0	0	0	0	0	0	0	0	0	0	0	0
	CPP-Small	0	0	0	0	0	0	0	0	0	0	0	0
	DBP	49	49	54	53	62	102	101	103	99	62	59	47
	SUB-TOTAL	**71**	**73**	**90**	**241**	**311**	**352**	**396**	**428**	**416**	**297**	**193**	**69**
Demand Response Aggregator-managed	CBP-DA	1	1	1	1	1	1	2	2	2	2	1	1
	CBP-DO	24	25	25	26	23	28	28	29	33	32	24	23
	AMP	83	82	82	82	80	78	77	79	77	77	83	83
	SUB-TOTAL	**108**	**108**	**109**	**109**	**104**	**107**	**107**	**110**	**112**	**111**	**108**	**108**
SmartConnect®-enabled	SPD with Tech.	1	1	0	10	12	12	14	15	16	14	1	1
	SUB-TOTAL	**1**	**1**	**0**	**10**	**12**	**12**	**14**	**15**	**16**	**14**	**1**	**1**
Nonevent Based	RTP	1	1	1	9	0	-7	17	2	23	9	7	1
	PLS	0*	0*	0*	0*	0*	0*	0*	0*	0*	0*	0*	0*
	SUB-TOTAL	**1**	**1**	**1**	**9**	**0**	**-7**	**17**	**2**	**23**	**9**	**7**	**1**
PORTFOLIO TOTAL		**745**	**758**	**798**	**1,013**	**1,133**	**1,172**	**1,230**	**1,276**	**1,257**	**1,127**	**945**	**759**

*Load impacts are redacted to protect confidential customer information

Table F-2: 2018 Program-specific Aggregate Ex Ante Load Impact Estimates for 1-in-10 SCE-specific System Conditions

Program Type	Program	Monthly System Peak											
		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Emergency	BIP-15	123	134	140	129	139	147	149	148	148	148	142	120
	BIP-30	435	433	432	470	509	499	488	508	490	498	451	427
	AP-I	24	26	34	49	55	55	53	54	43	42	33	25
	SUB-TOTAL	**582**	**593**	**606**	**648**	**703**	**702**	**690**	**710**	**681**	**688**	**626**	**572**
Price-responsive	SDP-C	7	9	13	27	32	29	32	37	38	31	19	7
	SDP-R	0	0	6	119	174	179	220	243	233	159	93	0
	CPP-Large	14	14	15	33	31	30	28	30	31	33	17	14
	CPP-Medium	0	0	0	0	0	0	0	0	0	4	2	1
	CPP-Small	0	0	0	0	0	0	0	0	0	1	0	0
	DBP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**21**	**23**	**34**	**180**	**238**	**239**	**281**	**310**	**302**	**228**	**130**	**23**
Demand Response Aggregator-managed	CBP-DA	3	3	3	3	3	4	5	5	6	6	3	3
	CBP-DO	37	38	39	40	35	43	43	45	51	49	36	36
	AMP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**40**	**42**	**42**	**43**	**38**	**47**	**48**	**50**	**56**	**54**	**40**	**39**
SmartConnect®-enabled	SPD with Tech.	1	1	0	15	17	17	19	21	22	19	2	1
	SUB-TOTAL	**1**	**1**	**0**	**15**	**17**	**17**	**19**	**21**	**22**	**19**	**2**	**1**
Nonevent Based	RTP	1	1	1	9	0	-7	17	2	23	9	7	1
	PLS	0	0	0	0	4	4	4	4	5	4	0	0
	SUB-TOTAL	**1**	**1**	**1**	**9**	**4**	**-3**	**21**	**7**	**27**	**13**	**7**	**1**
PORTFOLIO TOTAL		**645**	**659**	**682**	**894**	**1,000**	**1,001**	**1,059**	**1,097**	**1,088**	**1,002**	**804**	**636**

Table F-3: 2019 Program-specific Aggregate Ex Ante Load Impact Estimates for 1-in-10 SCE-specific System Conditions

Program Type	Program	Monthly System Peak											
		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Emergency	BIP-15	122	133	139	128	138	147	149	146	147	147	140	119
	BIP-30	426	424	424	460	497	487	476	496	478	485	440	416
	AP-I	24	26	35	49	55	56	53	54	43	42	33	25
	SUB-TOTAL	**573**	**583**	**597**	**637**	**690**	**690**	**678**	**697**	**668**	**674**	**614**	**561**
Price-responsive	SDP-C	6	8	12	25	30	27	30	34	35	29	17	6
	SDP-R	0	0	6	114	165	171	209	231	221	152	88	0
	CPP-Large	14	14	15	33	32	30	28	30	31	33	17	14
	CPP-Medium	1	1	1	4	4	4	4	4	4	10	4	3
	CPP-Small	0	0	0	1	1	1	1	1	1	6	5	4
	DBP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**22**	**24**	**35**	**176**	**231**	**233**	**273**	**300**	**293**	**230**	**130**	**28**
Demand Response Aggregator-managed	CBP-DA	3	3	3	3	3	4	5	5	6	6	3	3
	CBP-DO	37	38	39	40	35	43	43	45	51	49	36	36
	AMP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**40**	**42**	**42**	**43**	**38**	**47**	**48**	**50**	**56**	**54**	**40**	**39**
SmartConnect®-enabled	SPD with Tech.	2	2	0	19	22	21	24	26	27	23	2	2
	SUB-TOTAL	**2**	**2**	**0**	**19**	**22**	**21**	**24**	**26**	**27**	**23**	**2**	**2**
Nonevent Based	RTP	1	1	1	9	0	-7	17	2	23	9	7	1
	PLS	0	0	0	0	5	5	6	6	6	5	0	0
	SUB-TOTAL	**1**	**1**	**1**	**9**	**5**	**-2**	**22**	**8**	**28**	**14**	**7**	**1**
PORTFOLIO TOTAL		**637**	**651**	**674**	**884**	**986**	**989**	**1,045**	**1,081**	**1,073**	**995**	**793**	**630**

Table F-4: 2020 Program-specific Aggregate Ex Ante Load Impact Estimates for 1-in-10 SCE-specific System Conditions

Program Type	Program	Monthly System Peak											
		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Emergency	BIP-15	121	132	138	127	137	146	148	145	145	146	136	115
	BIP-30	416	412	413	450	487	479	467	486	468	475	431	408
	AP-I	24	26	35	49	55	55	53	54	43	42	33	25
	SUB-TOTAL	**562**	**571**	**585**	**626**	**679**	**680**	**668**	**685**	**657**	**663**	**600**	**548**
Price-responsive	SDP-C	6	7	11	23	27	25	28	32	33	27	16	6
	SDP-R	0	0	5	108	157	162	199	220	211	144	84	0
	CPP-Large	14	14	15	33	32	30	28	30	31	33	17	14
	CPP-Medium	3	3	4	9	10	10	10	11	11	4	2	1
	CPP-Small	4	4	4	6	6	7	7	8	8	3	2	2
	DBP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**27**	**29**	**39**	**179**	**232**	**234**	**273**	**300**	**292**	**211**	**120**	**23**
Demand Response Aggregator-managed	CBP-DA	3	3	3	3	3	4	5	5	6	6	3	3
	CBP-DO	37	38	39	40	35	43	43	45	51	49	36	36
	AMP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**40**	**42**	**42**	**43**	**38**	**47**	**48**	**50**	**56**	**54**	**40**	**39**
SmartConnect®-enabled	SPD with Tech.	2	2	-1	23	27	26	29	31	32	28	2	2
	SUB-TOTAL	**2**	**2**	**-1**	**23**	**27**	**26**	**29**	**31**	**32**	**28**	**2**	**2**
Nonevent Based	RTP	1	1	1	9	0	-7	17	2	23	9	7	1
	PLS	0	0	0	0	5	6	6	6	6	6	0	0
	SUB-TOTAL	**1**	**1**	**1**	**9**	**6**	**-1**	**23**	**9**	**29**	**14**	**7**	**1**
PORTFOLIO TOTAL		**632**	**644**	**666**	**880**	**981**	**985**	**1,041**	**1,075**	**1,067**	**970**	**768**	**613**

Table F-5: 2021 Program-specific Aggregate Ex Ante Load Impact Estimates for 1-in-10 SCE-specific System Conditions

Program Type	Program	Monthly System Peak											
		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Emergency	BIP-15	117	128	133	123	132	141	143	140	141	140	134	113
	BIP-30	407	405	406	440	479	469	458	477	460	466	423	401
	AP-I	24	26	34	49	54	55	52	53	42	41	32	25
	SUB-TOTAL	**548**	**559**	**573**	**612**	**665**	**665**	**653**	**670**	**643**	**647**	**589**	**539**
Price-responsive	SDP-C	5	7	10	21	25	23	25	29	30	24	15	5
	SDP-R	0	0	5	103	150	154	189	209	200	137	80	0
	CPP-Large	14	15	15	33	32	30	28	30	31	34	17	14
	CPP-Medium	1	1	1	4	4	4	4	4	4	4	2	1
	CPP-Small	2	2	2	2	3	3	3	3	3	3	2	2
	DBP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**22**	**24**	**34**	**163**	**213**	**214**	**250**	**275**	**269**	**201**	**114**	**23**
Demand Response Aggregator-managed	CBP-DA	3	3	3	3	3	4	5	5	6	6	3	3
	CBP-DO	37	38	39	40	35	43	43	45	51	49	36	36
	AMP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**40**	**42**	**42**	**43**	**38**	**47**	**48**	**50**	**56**	**54**	**40**	**39**
SmartConnect®-enabled	SPD with Tech.	2	2	-1	27	31	30	34	37	38	32	3	3
	SUB-TOTAL	**2**	**2**	**-1**	**27**	**31**	**30**	**34**	**37**	**38**	**32**	**3**	**3**
Nonevent Based	RTP	1	1	1	9	0	-7	17	2	23	9	7	1
	PLS	0	0	0	0	6	6	7	7	7	6	0	0
	SUB-TOTAL	**1**	**1**	**1**	**9**	**6**	**-1**	**23**	**9**	**29**	**15**	**7**	**1**
PORTFOLIO TOTAL		**613**	**628**	**649**	**854**	**953**	**955**	**1,008**	**1,041**	**1,035**	**950**	**753**	**604**

Table F-6: 2022 Program-specific Aggregate Ex Ante Load Impact Estimates for 1-in-10 SCE-specific System Conditions

Program Type	Program	Monthly System Peak											
		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Emergency	BIP-15	116	127	132	121	131	139	141	140	140	140	134	113
	BIP-30	400	398	398	431	469	461	449	468	452	459	418	396
	AP-I	24	25	34	48	53	54	51	52	42	41	32	24
	SUB-TOTAL	**539**	**550**	**563**	**600**	**653**	**654**	**641**	**660**	**634**	**640**	**583**	**533**
Price-responsive	SDP-C	5	6	9	20	23	21	23	27	28	22	13	5
	SDP-R	0	0	5	98	142	146	180	198	190	130	76	0
	CPP-Large	14	15	15	33	32	30	29	30	31	34	17	14
	CPP-Medium	1	1	1	4	4	4	4	4	4	4	2	1
	CPP-Small	2	2	2	2	3	3	3	3	3	3	2	2
	DBP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**22**	**24**	**33**	**156**	**204**	**205**	**239**	**263**	**256**	**193**	**109**	**22**
Demand Response Aggregator-managed	CBP-DA	3	3	3	3	3	4	5	5	6	6	3	3
	CBP-DO	37	38	39	40	35	43	43	45	51	49	36	36
	AMP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**40**	**42**	**42**	**43**	**38**	**47**	**48**	**50**	**56**	**54**	**40**	**39**
SmartConnect®-enabled	SPD with Tech.	3	3	-1	31	36	35	39	42	43	37	3	3
	SUB-TOTAL	**3**	**3**	**-1**	**31**	**36**	**35**	**39**	**42**	**43**	**37**	**3**	**3**
Nonevent Based	RTP	1	1	1	9	0	-7	17	2	23	9	7	1
	PLS	0	0	0	0	6	6	7	7	7	6	0	0
	SUB-TOTAL	**1**	**1**	**1**	**9**	**6**	**0**	**24**	**10**	**30**	**15**	**7**	**1**
PORTFOLIO TOTAL		**604**	**618**	**638**	**840**	**936**	**940**	**991**	**1,024**	**1,020**	**939**	**742**	**599**

Table F-7: 2023 Program-specific Aggregate Ex Ante Load Impact Estimates for 1-in-10 SCE-specific System Conditions

Program Type	Program	Monthly System Peak											
		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Emergency	BIP-15	116	127	132	121	131	139	141	140	140	140	134	113
	BIP-30	396	394	395	429	467	459	449	468	452	459	418	396
	AP-I	23	25	33	48	53	54	51	52	42	41	32	24
	SUB-TOTAL	**535**	**546**	**560**	**598**	**651**	**652**	**641**	**660**	**634**	**640**	**583**	**533**
Price-responsive	SDP-C	4	6	9	18	21	19	22	25	25	21	12	5
	SDP-R	0	0	5	93	135	139	171	188	181	124	72	0
	CPP-Large	14	15	15	33	32	30	29	30	31	34	17	14
	CPP-Medium	1	1	1	4	4	4	4	4	4	4	2	1
	CPP-Small	2	2	2	2	3	3	3	3	3	3	2	2
	DBP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**22**	**23**	**32**	**150**	**195**	**196**	**228**	**251**	**245**	**184**	**104**	**22**
Demand Response Aggregator-managed	CBP-DA	3	3	3	3	3	4	5	5	6	6	3	3
	CBP-DO	37	38	39	40	35	43	43	45	51	49	36	36
	AMP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**40**	**42**	**42**	**43**	**38**	**47**	**48**	**50**	**56**	**54**	**40**	**39**
SmartConnect®-enabled	SPD with Tech.	3	3	-1	35	41	39	44	47	49	41	3	3
	SUB-TOTAL	**3**	**3**	**-1**	**35**	**41**	**39**	**44**	**47**	**49**	**41**	**3**	**3**
Nonevent Based	RTP	1	1	1	9	0	-7	17	2	23	9	7	1
	PLS	0	0	0	0	6	7	7	8	8	7	0	0
	SUB-TOTAL	**1**	**1**	**1**	**9**	**7**	**0**	**24**	**10**	**30**	**15**	**7**	**1**
PORTFOLIO TOTAL		**600**	**614**	**633**	**836**	**930**	**934**	**985**	**1,018**	**1,014**	**935**	**738**	**599**

Table F-8: 2024 Program-specific Aggregate Ex Ante Load Impact Estimates for 1-in-10 SCE-specific System Conditions

Program Type	Program	Monthly System Peak											
		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Emergency	BIP-15	116	127	132	121	131	139	141	140	140	140	134	113
	BIP-30	396	394	395	429	467	459	449	468	452	459	418	396
	AP-I	23	25	33	48	53	54	51	52	42	41	32	24
	SUB-TOTAL	**535**	**546**	**560**	**598**	**651**	**652**	**641**	**660**	**634**	**640**	**583**	**533**
Price-responsive	SDP-C	4	5	8	17	19	18	20	23	23	19	11	4
	SDP-R	0	0	4	88	128	132	162	179	172	117	68	0
	CPP-Large	14	15	15	33	32	31	29	30	31	34	17	14
	CPP-Medium	1	1	1	4	4	4	4	4	4	4	2	1
	CPP-Small	2	2	2	2	3	3	3	3	3	3	2	2
	DBP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**21**	**23**	**31**	**144**	**186**	**187**	**218**	**239**	**234**	**177**	**100**	**22**
Demand Response Aggregator-managed	CBP-DA	3	3	3	3	3	4	5	5	6	6	3	3
	CBP-DO	37	38	39	40	35	43	43	45	51	49	36	36
	AMP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**40**	**42**	**42**	**43**	**38**	**47**	**48**	**50**	**56**	**54**	**40**	**39**
SmartConnect®-enabled	SPD with Tech.	3	3	-1	40	45	43	49	53	54	46	4	4
	SUB-TOTAL	**3**	**3**	**-1**	**40**	**45**	**43**	**49**	**53**	**54**	**46**	**4**	**4**
Nonevent Based	RTP	1	1	1	9	0	-7	17	2	23	9	7	1
	PLS	0	0	0	0	6	7	7	8	8	7	0	0
	SUB-TOTAL	**1**	**1**	**1**	**9**	**7**	**0**	**24**	**10**	**30**	**15**	**7**	**1**
PORTFOLIO TOTAL		**600**	**614**	**632**	**834**	**927**	**930**	**980**	**1,012**	**1,008**	**932**	**733**	**599**

Table F-9: 2025 Program-specific Aggregate Ex Ante Load Impact Estimates for 1-in-10 SCE-specific System Conditions

Program Type	Program	Monthly System Peak											
		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Emergency	BIP-15	116	127	132	121	131	139	141	140	140	140	134	113
	BIP-30	396	394	395	429	467	459	449	468	452	459	418	396
	AP-I	23	25	33	48	53	54	51	52	42	41	32	24
	SUB-TOTAL	**535**	**546**	**560**	**598**	**651**	**652**	**641**	**660**	**634**	**640**	**583**	**533**
Price-responsive	SDP-C	4	5	7	15	18	16	18	21	21	17	10	4
	SDP-R	0	0	4	84	122	125	154	170	163	111	65	0
	CPP-Large	14	15	15	33	32	31	29	30	31	34	17	14
	CPP-Medium	1	1	1	4	4	4	4	4	4	4	2	1
	CPP-Small	2	2	2	2	3	3	3	3	3	3	2	2
	DBP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**21**	**22**	**30**	**138**	**178**	**179**	**208**	**228**	**223**	**169**	**95**	**21**
Demand Response Aggregator-managed	CBP-DA	3	3	3	3	3	4	5	5	6	6	3	3
	CBP-DO	37	38	39	40	35	43	43	45	51	49	36	36
	AMP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**40**	**42**	**42**	**43**	**38**	**47**	**48**	**50**	**56**	**54**	**40**	**39**
SmartConnect®-enabled	SPD with Tech.	4	4	-1	44	50	48	54	58	60	50	4	4
	SUB-TOTAL	**4**	**4**	**-1**	**44**	**50**	**48**	**54**	**58**	**60**	**50**	**4**	**4**
Nonevent Based	RTP	1	1	1	9	0	-7	17	2	23	9	7	1
	PLS	0	0	0	0	6	7	7	8	8	7	0	0
	SUB-TOTAL	**1**	**1**	**1**	**9**	**7**	**0**	**24**	**10**	**30**	**15**	**7**	**1**
PORTFOLIO TOTAL		**600**	**614**	**631**	**832**	**923**	**926**	**975**	**1,006**	**1,003**	**929**	**729**	**599**

Table F-10: 2026 Program-specific Aggregate Ex Ante Load Impact Estimates for 1-in-10 SCE-specific System Conditions

Program Type	Program	Monthly System Peak											
		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Emergency	BIP-15	116	127	132	121	131	139	141	140	140	140	134	113
	BIP-30	396	394	395	429	467	459	449	468	452	459	418	396
	AP-I	23	25	33	48	53	54	51	52	42	41	32	24
	SUB-TOTAL	**535**	**546**	**560**	**598**	**651**	**652**	**641**	**660**	**634**	**640**	**583**	**533**
Price-responsive	SDP-C	3	4	7	14	16	15	16	19	19	16	9	4
	SDP-R	0	0	4	79	115	119	146	161	154	106	61	0
	CPP-Large	14	15	15	33	32	31	29	30	32	34	17	14
	CPP-Medium	1	1	1	4	4	4	4	4	4	4	2	1
	CPP-Small	2	2	2	2	3	3	3	3	3	3	2	2
	DBP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**21**	**22**	**29**	**133**	**170**	**171**	**198**	**218**	**213**	**162**	**91**	**21**
Demand Response Aggregator-managed	CBP-DA	3	3	3	3	3	4	5	5	6	6	3	3
	CBP-DO	37	38	39	40	35	43	43	45	51	49	36	36
	AMP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**40**	**42**	**42**	**43**	**38**	**47**	**48**	**50**	**56**	**54**	**40**	**39**
SmartConnect®-enabled	SPD with Tech.	4	4	-1	48	55	52	59	63	65	55	5	4
	SUB-TOTAL	**4**	**4**	**-1**	**48**	**55**	**52**	**59**	**63**	**65**	**55**	**5**	**4**
Nonevent Based	RTP	1	1	1	9	0	-7	17	2	23	9	7	1
	PLS	0	0	0	0	6	7	7	7	7	6	0	0
	SUB-TOTAL	**1**	**1**	**1**	**9**	**6**	**0**	**24**	**10**	**30**	**15**	**7**	**1**
PORTFOLIO TOTAL		**600**	**614**	**630**	**831**	**920**	**922**	**970**	**1,001**	**998**	**926**	**726**	**599**

Table F-11: 2027 Program-specific Aggregate Ex Ante Load Impact Estimates for 1-in-10 SCE-specific System Conditions

Program Type	Program	Monthly System Peak											
		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Emergency	BIP-15	116	127	132	121	131	139	141	140	140	140	134	113
	BIP-30	396	394	395	429	467	459	449	468	452	459	418	396
	AP-I	23	25	33	48	53	54	51	52	42	41	32	24
	SUB-TOTAL	**535**	**546**	**560**	**598**	**651**	**652**	**641**	**660**	**634**	**640**	**583**	**533**
Price-responsive	SDP-C	3	4	6	13	15	14	15	17	18	14	9	3
	SDP-R	0	0	4	75	109	113	138	153	146	100	58	0
	CPP-Large	14	15	15	34	32	31	29	30	32	34	17	15
	CPP-Medium	1	1	1	4	4	4	4	4	4	4	2	1
	CPP-Small	2	2	2	2	3	3	3	3	3	3	2	2
	DBP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**20**	**22**	**28**	**127**	**163**	**164**	**190**	**208**	**203**	**155**	**87**	**21**
Demand Response Aggregator-managed	CBP-DA	3	3	3	3	3	4	5	5	6	6	3	3
	CBP-DO	37	38	39	40	35	43	43	45	51	49	36	36
	AMP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**40**	**42**	**42**	**43**	**38**	**47**	**48**	**50**	**56**	**54**	**40**	**39**
SmartConnect®-enabled	SPD with Tech.	4	4	-1	52	59	57	64	69	70	59	5	5
	SUB-TOTAL	**4**	**4**	**-1**	**52**	**59**	**57**	**64**	**69**	**70**	**59**	**5**	**5**
Nonevent Based	RTP	1	1	1	9	0	-7	17	2	23	9	7	1
	PLS	0	0	0	0	6	6	7	7	7	6	0	0
	SUB-TOTAL	**1**	**1**	**1**	**9**	**6**	**0**	**24**	**10**	**30**	**15**	**7**	**1**
PORTFOLIO TOTAL		**600**	**614**	**629**	**829**	**917**	**919**	**966**	**996**	**993**	**924**	**722**	**599**

Appendix G Portfolio Aggregate Ex Ante Load Impact Estimates for 1-in-2 CAISO System Conditions by Month and Forecast Year

Table G-1: 2017 Portfolio Aggregate Ex Ante Load Impact Estimates for 1-in-2 CAISO System Conditions

Program Type	Program	Monthly System Peak											
		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Emergency	BIP-15	108	112	122	124	136	147	149	149	149	149	144	128
	BIP-30	432	437	433	469	502	490	489	511	486	500	453	433
	AP-I	22	25	30	43	53	54	52	51	43	37	24	24
	SUB-TOTAL	**562**	**574**	**584**	**636**	**691**	**692**	**690**	**711**	**677**	**686**	**621**	**584**
Price-responsive	SDP-C	8	8	9	19	22	27	34	36	35	25	14	9
	SDP-R	0	0	0	33	78	140	214	211	193	85	4	0
	CPP-Large	8	8	7	17	17	16	16	16	17	18	8	8
	CPP-Medium	0	0	0	0	0	0	0	0	0	0	0	0
	CPP-Small	0	0	0	0	0	0	0	0	0	0	0	0
	DBP	4	4	4	5	5	5	5	5	5	5	4	4
	SUB-TOTAL	**20**	**20**	**20**	**74**	**121**	**188**	**268**	**268**	**251**	**132**	**31**	**21**
Demand Response Aggregator-managed	CBP-DA	1	1	1	1	1	1	2	2	2	2	1	1
	CBP-DO	24	25	25	26	23	28	28	29	33	32	24	24
	AMP	83	82	82	82	80	78	77	79	77	77	83	83
	SUB-TOTAL	**108**	**108**	**108**	**109**	**104**	**107**	**107**	**110**	**112**	**111**	**108**	**108**
SmartConnect®-enabled	SPD with Tech.	0	0	-1	6	6	8	11	11	11	9	0	1
	SUB-TOTAL	**0**	**0**	**-1**	**6**	**6**	**8**	**11**	**11**	**11**	**9**	**0**	**1**
Nonevent Based	RTP	0	0	0	0	0	-1	1	4	1	0	0	0
	PLS	0*	0*	0*	0*	0*	0*	0*	0*	0*	0*	0*	0*
	SUB-TOTAL	**0**	**0**	**0**	**0**	**0**	**-1**	**1**	**4**	**1**	**0**	**0**	**0**
PORTFOLIO TOTAL		**691**	**703**	**711**	**824**	**922**	**993**	**1,077**	**1,103**	**1,052**	**938**	**759**	**714**

*Load impacts are redacted to protect confidential customer information

Table G-2: 2018 Portfolio Aggregate Ex Ante Load Impact Estimates for 1-in-2 CAISO System Conditions

Program Type	Program	Monthly System Peak											
		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Emergency	BIP-15	125	129	129	130	138	147	149	147	148	148	143	127
	BIP-30	433	436	430	465	496	484	482	501	477	491	445	425
	AP-I	23	25	30	44	54	55	53	51	43	38	24	24
	SUB-TOTAL	**580**	**591**	**589**	**639**	**688**	**686**	**683**	**700**	**667**	**677**	**611**	**576**
Price-responsive	SDP-C	7	8	8	18	20	25	31	33	33	23	13	8
	SDP-R	0	0	0	32	74	133	203	200	184	80	4	0
	CPP-Large	8	8	7	17	17	16	16	17	17	18	8	8
	CPP-Medium	0	0	0	0	0	0	0	0	0	3	1	1
	CPP-Small	0	0	0	0	0	0	0	0	0	1	0	0
	DBP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**15**	**16**	**16**	**66**	**111**	**174**	**250**	**250**	**234**	**125**	**27**	**18**
Demand Response Aggregator-managed	CBP-DA	3	3	3	3	3	4	5	5	6	6	3	3
	CBP-DO	37	38	38	40	35	43	43	45	51	49	36	36
	AMP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**40**	**42**	**41**	**43**	**38**	**47**	**48**	**50**	**56**	**54**	**40**	**40**
SmartConnect®-enabled	SPD with Tech.	1	1	-2	10	11	14	18	19	19	14	0	1
	SUB-TOTAL	**1**	**1**	**-2**	**10**	**11**	**14**	**18**	**19**	**19**	**14**	**0**	**1**
Nonevent Based	RTP	0	0	0	0	0	-1	1	4	1	0	0	0
	PLS	0	0	0	0	3	4	4	4	4	4	0	0
	SUB-TOTAL	**0**	**0**	**0**	**0**	**3**	**2**	**5**	**8**	**5**	**4**	**0**	**0**
PORTFOLIO TOTAL		**636**	**649**	**644**	**759**	**852**	**923**	**1,004**	**1,026**	**981**	**875**	**677**	**634**

Table G-3: 2019 Portfolio Aggregate Ex Ante Load Impact Estimates for 1-in-2 CAISO System Conditions

Program Type	Program	Monthly System Peak											
		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Emergency	BIP-15	124	128	128	129	137	147	149	146	147	147	141	126
	BIP-30	424	427	422	455	484	472	469	489	465	478	434	414
	AP-I	23	26	30	44	55	55	53	52	43	38	24	24
	SUB-TOTAL	**570**	**581**	**581**	**629**	**675**	**674**	**672**	**687**	**655**	**663**	**599**	**564**
Price-responsive	SDP-C	7	7	7	16	19	23	29	31	30	21	12	8
	SDP-R	0	0	0	30	70	126	193	190	175	77	4	0
	CPP-Large	8	8	8	17	17	16	16	17	17	18	8	8
	CPP-Medium	1	1	1	3	3	4	4	4	4	9	3	3
	CPP-Small	0	0	0	1	1	1	1	1	1	6	4	4
	DBP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**16**	**16**	**16**	**67**	**110**	**170**	**243**	**242**	**227**	**130**	**31**	**23**
Demand Response Aggregator-managed	CBP-DA	3	3	3	3	3	4	5	5	6	6	3	3
	CBP-DO	37	38	38	40	35	43	43	45	51	49	36	36
	AMP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**40**	**42**	**41**	**43**	**38**	**47**	**48**	**50**	**56**	**54**	**40**	**40**
SmartConnect®-enabled	SPD with Tech.	1	1	-3	13	14	18	23	24	24	18	-1	1
	SUB-TOTAL	**1**	**1**	**-3**	**13**	**14**	**18**	**23**	**24**	**24**	**18**	**-1**	**1**
Nonevent Based	RTP	0	0	0	0	0	-1	1	4	1	0	0	0
	PLS	0	0	0	0	4	5	6	5	6	5	0	0
	SUB-TOTAL	**0**	**0**	**0**	**0**	**5**	**3**	**6**	**9**	**6**	**5**	**0**	**0**
PORTFOLIO TOTAL		**627**	**640**	**635**	**752**	**842**	**913**	**991**	**1,012**	**968**	**870**	**669**	**628**

Table G-4: 2020 Portfolio Aggregate Ex Ante Load Impact Estimates for 1-in-2 CAISO System Conditions

Program Type	Program	Monthly System Peak											
		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Emergency	BIP-15	123	127	127	128	136	146	148	145	145	146	136	122
	BIP-30	414	415	412	445	474	464	461	479	456	469	425	406
	AP-I	23	26	30	44	54	55	53	51	43	37	24	24
	SUB-TOTAL	**560**	**568**	**569**	**618**	**665**	**665**	**662**	**676**	**644**	**653**	**585**	**551**
Price-responsive	SDP-C	6	7	7	15	17	21	27	28	28	20	11	7
	SDP-R	0	0	0	29	67	120	184	181	166	73	3	0
	CPP-Large	8	8	8	17	17	16	16	17	17	18	8	8
	CPP-Medium	3	3	3	8	8	9	10	10	10	4	1	1
	CPP-Small	4	4	4	5	5	6	7	7	7	2	2	2
	DBP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**21**	**22**	**21**	**74**	**115**	**173**	**244**	**243**	**228**	**116**	**26**	**18**
Demand Response Aggregator-managed	CBP-DA	3	3	3	3	3	4	5	5	6	6	3	3
	CBP-DO	37	38	38	40	35	43	43	45	51	49	36	36
	AMP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**40**	**42**	**41**	**43**	**38**	**47**	**48**	**50**	**56**	**54**	**40**	**40**
SmartConnect®-enabled	SPD with Tech.	1	1	-4	16	17	22	28	28	28	21	-1	1
	SUB-TOTAL	**1**	**1**	**-4**	**16**	**17**	**22**	**28**	**28**	**28**	**21**	**-1**	**1**
Nonevent Based	RTP	0	0	0	0	0	-1	1	4	1	0	0	0
	PLS	0	0	0	0	5	5	6	6	6	5	0	0
	SUB-TOTAL	**0**	**0**	**0**	**0**	**5**	**4**	**7**	**9**	**7**	**5**	**0**	**0**
PORTFOLIO TOTAL		**622**	**633**	**628**	**751**	**839**	**911**	**987**	**1,007**	**963**	**850**	**650**	**611**

Table G-5: 2021 Portfolio Aggregate Ex Ante Load Impact Estimates for 1-in-2 CAISO System Conditions

Program Type	Program	Monthly System Peak											
		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Emergency	BIP-15	119	123	123	124	131	141	143	140	141	140	135	120
	BIP-30	405	408	404	436	466	455	452	470	447	460	417	399
	AP-I	23	25	30	44	54	54	52	51	42	37	23	23
	SUB-TOTAL	**546**	**557**	**558**	**603**	**651**	**650**	**647**	**661**	**630**	**637**	**575**	**542**
Price-responsive	SDP-C	6	6	6	14	16	19	24	26	26	18	10	7
	SDP-R	0	0	0	27	64	114	175	172	158	69	3	0
	CPP-Large	8	8	8	17	17	16	16	17	17	18	8	8
	CPP-Medium	1	1	1	3	3	4	4	4	4	4	1	1
	CPP-Small	2	2	2	2	2	3	3	3	3	2	2	2
	DBP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**16**	**17**	**17**	**63**	**102**	**156**	**222**	**222**	**208**	**111**	**25**	**18**
Demand Response Aggregator-managed	CBP-DA	3	3	3	3	3	4	5	5	6	6	3	3
	CBP-DO	37	38	38	40	35	43	43	45	51	49	36	36
	AMP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**40**	**42**	**41**	**43**	**38**	**47**	**48**	**50**	**56**	**54**	**40**	**40**
SmartConnect®-enabled	SPD with Tech.	1	1	-5	19	20	26	33	33	33	25	-1	2
	SUB-TOTAL	**1**	**1**	**-5**	**19**	**20**	**26**	**33**	**33**	**33**	**25**	**-1**	**2**
Nonevent Based	RTP	0	0	0	0	0	-1	1	4	1	0	0	0
	PLS	0	0	0	0	5	6	7	6	7	6	0	0
	SUB-TOTAL	**0**	**0**	**0**	**0**	**5**	**4**	**7**	**10**	**7**	**6**	**0**	**0**
PORTFOLIO TOTAL		**604**	**616**	**611**	**728**	**816**	**883**	**956**	**976**	**934**	**833**	**638**	**601**

Table G-6: 2022 Portfolio Aggregate Ex Ante Load Impact Estimates for 1-in-2 CAISO System Conditions

Program Type	Program	Monthly System Peak											
		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Emergency	BIP-15	117	122	122	122	129	140	141	140	140	140	135	120
	BIP-30	397	401	397	427	457	447	443	462	440	453	411	394
	AP-I	22	25	30	43	53	53	51	50	42	36	23	23
	SUB-TOTAL	**537**	**547**	**548**	**592**	**639**	**639**	**635**	**651**	**622**	**630**	**569**	**537**
Price-responsive	SDP-C	5	6	6	13	15	18	22	24	24	17	9	6
	SDP-R	0	0	0	26	61	108	166	163	150	66	3	0
	CPP-Large	8	8	8	17	17	16	16	17	17	18	8	8
	CPP-Medium	1	1	1	3	3	4	4	4	4	4	1	1
	CPP-Small	2	2	2	2	2	3	3	3	3	2	2	2
	DBP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**16**	**16**	**16**	**61**	**97**	**149**	**211**	**211**	**198**	**106**	**24**	**17**
Demand Response Aggregator-managed	CBP-DA	3	3	3	3	3	4	5	5	6	6	3	3
	CBP-DO	37	38	38	40	35	43	43	45	51	49	36	36
	AMP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**40**	**42**	**41**	**43**	**38**	**47**	**48**	**50**	**56**	**54**	**40**	**40**
SmartConnect®-enabled	SPD with Tech.	2	2	-5	21	23	29	38	38	38	29	-1	2
	SUB-TOTAL	**2**	**2**	**-5**	**21**	**23**	**29**	**38**	**38**	**38**	**29**	**-1**	**2**
Nonevent Based	RTP	0	0	0	0	0	-1	1	4	1	0	0	0
	PLS	0	0	0	0	6	6	7	7	7	6	0	0
	SUB-TOTAL	**0**	**0**	**0**	**0**	**6**	**5**	**7**	**10**	**7**	**6**	**0**	**0**
PORTFOLIO TOTAL		**595**	**607**	**600**	**717**	**803**	**869**	**939**	**961**	**921**	**825**	**632**	**595**

Table G-7: 2023 Portfolio Aggregate Ex Ante Load Impact Estimates for 1-in-2 CAISO System Conditions

Program Type	Program	Monthly System Peak											
		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Emergency	BIP-15	117	122	122	122	129	140	141	140	140	140	135	120
	BIP-30	394	397	393	425	455	445	443	462	440	453	411	394
	AP-I	22	25	29	43	52	53	51	50	42	36	23	23
	SUB-TOTAL	**533**	**543**	**544**	**590**	**637**	**638**	**635**	**651**	**622**	**630**	**569**	**537**
Price-responsive	SDP-C	5	5	5	12	13	16	21	22	22	15	8	6
	SDP-R	0	0	0	25	58	103	158	155	143	62	3	0
	CPP-Large	8	8	8	17	17	17	16	17	17	18	8	8
	CPP-Medium	1	1	1	3	3	4	4	4	4	4	1	1
	CPP-Small	2	2	2	2	2	3	3	3	3	2	2	2
	DBP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**15**	**16**	**16**	**59**	**93**	**142**	**201**	**201**	**188**	**101**	**23**	**17**
Demand Response Aggregator-managed	CBP-DA	3	3	3	3	3	4	5	5	6	6	3	3
	CBP-DO	37	38	38	40	35	43	43	45	51	49	36	36
	AMP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**40**	**42**	**41**	**43**	**38**	**47**	**48**	**50**	**56**	**54**	**40**	**40**
SmartConnect®-enabled	SPD with Tech.	2	2	-6	24	26	33	42	43	42	32	-1	2
	SUB-TOTAL	**2**	**2**	**-6**	**24**	**26**	**33**	**42**	**43**	**42**	**32**	**-1**	**2**
Nonevent Based	RTP	0	0	0	0	0	-1	1	4	1	0	0	0
	PLS	0	0	0	0	6	6	7	7	7	6	0	0
	SUB-TOTAL	**0**	**0**	**0**	**0**	**6**	**5**	**8**	**11**	**8**	**6**	**0**	**0**
PORTFOLIO TOTAL		**590**	**603**	**595**	**716**	**800**	**865**	**934**	**956**	**916**	**824**	**631**	**595**

Table G-8: 2024 Portfolio Aggregate Ex Ante Load Impact Estimates for 1-in-2 CAISO System Conditions

Program Type	Program	Monthly System Peak											
		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Emergency	BIP-15	117	122	122	122	129	140	141	140	140	140	135	120
	BIP-30	394	397	393	425	455	445	443	462	440	453	411	394
	AP-I	22	25	29	43	52	53	51	50	42	36	23	23
	SUB-TOTAL	**533**	**543**	**544**	**590**	**637**	**638**	**635**	**651**	**622**	**630**	**569**	**537**
Price-responsive	SDP-C	4	5	5	11	12	15	19	20	20	14	8	5
	SDP-R	0	0	0	23	55	98	150	147	135	59	3	0
	CPP-Large	8	8	8	17	17	17	16	17	17	18	8	8
	CPP-Medium	1	1	1	3	3	4	4	4	4	4	1	1
	CPP-Small	2	2	2	2	2	3	3	3	3	2	2	2
	DBP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**15**	**15**	**15**	**56**	**89**	**136**	**192**	**191**	**179**	**97**	**22**	**16**
Demand Response Aggregator-managed	CBP-DA	3	3	3	3	3	4	5	5	6	6	3	3
	CBP-DO	37	38	38	40	35	43	43	45	51	49	36	36
	AMP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**40**	**42**	**41**	**43**	**38**	**47**	**48**	**50**	**56**	**54**	**40**	**40**
SmartConnect®-enabled	SPD with Tech.	2	2	-7	27	29	37	47	48	47	36	-1	2
	SUB-TOTAL	**2**	**2**	**-7**	**27**	**29**	**37**	**47**	**48**	**47**	**36**	**-1**	**2**
Nonevent Based	RTP	0	0	0	0	0	-1	1	4	1	0	0	0
	PLS	0	0	0	0	6	6	7	7	7	6	0	0
	SUB-TOTAL	**0**	**0**	**0**	**0**	**6**	**5**	**8**	**11**	**8**	**6**	**0**	**0**
PORTFOLIO TOTAL		**590**	**603**	**594**	**717**	**800**	**862**	**929**	**951**	**912**	**823**	**630**	**595**

Table G-9: 2025 Portfolio Aggregate Ex Ante Load Impact Estimates for 1-in-2 CAISO System Conditions

Program Type	Program	Monthly System Peak											
		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Emergency	BIP-15	117	122	122	122	129	140	141	140	140	140	135	120
	BIP-30	394	397	393	425	455	445	443	462	440	453	411	394
	AP-I	22	25	29	43	52	53	51	50	42	36	23	23
	SUB-TOTAL	**533**	**543**	**544**	**590**	**637**	**638**	**635**	**651**	**622**	**630**	**569**	**537**
Price-responsive	SDP-C	4	4	4	10	11	14	17	18	18	13	7	5
	SDP-R	0	0	0	22	52	93	142	140	128	56	3	0
	CPP-Large	8	8	8	17	17	17	16	17	17	18	8	8
	CPP-Medium	1	1	1	3	3	4	4	4	4	4	1	1
	CPP-Small	2	2	2	2	2	3	3	3	3	2	2	2
	DBP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**15**	**15**	**15**	**54**	**85**	**129**	**182**	**182**	**171**	**93**	**21**	**16**
Demand Response Aggregator-managed	CBP-DA	3	3	3	3	3	4	5	5	6	6	3	3
	CBP-DO	37	38	38	40	35	43	43	45	51	49	36	36
	AMP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**40**	**42**	**41**	**43**	**38**	**47**	**48**	**50**	**56**	**54**	**40**	**40**
SmartConnect®-enabled	SPD with Tech.	2	2	-7	30	32	41	52	53	52	39	-1	2
	SUB-TOTAL	**2**	**2**	**-7**	**30**	**32**	**41**	**52**	**53**	**52**	**39**	**-1**	**2**
Nonevent Based	RTP	0	0	0	0	0	-1	1	4	1	0	0	0
	PLS	0	0	0	0	6	6	7	7	7	6	0	0
	SUB-TOTAL	**0**	**0**	**0**	**0**	**6**	**5**	**8**	**11**	**8**	**6**	**0**	**0**
PORTFOLIO TOTAL		**590**	**602**	**593**	**717**	**799**	**860**	**925**	**946**	**908**	**822**	**629**	**595**

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Table G-10: 2026 Portfolio Aggregate Ex Ante Load Impact Estimates for 1-in-2 CAISO System Conditions

Program Type	Program	Monthly System Peak											
		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Emergency	BIP-15	117	122	122	122	129	140	141	140	140	140	135	120
	BIP-30	394	397	393	425	455	445	443	462	440	453	411	394
	AP-I	22	25	29	43	52	53	51	50	42	36	23	23
	SUB-TOTAL	**533**	**543**	**544**	**590**	**637**	**638**	**635**	**651**	**622**	**630**	**569**	**537**
Price-responsive	SDP-C	4	4	4	9	10	13	16	17	17	12	6	4
	SDP-R	0	0	0	21	49	88	135	133	122	53	3	0
	CPP-Large	8	8	8	17	17	17	16	17	17	18	8	8
	CPP-Medium	1	1	1	3	3	4	4	4	4	4	1	1
	CPP-Small	2	2	2	2	2	3	3	3	3	2	2	2
	DBP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**14**	**15**	**15**	**52**	**82**	**123**	**174**	**174**	**163**	**89**	**21**	**15**
Demand Response Aggregator-managed	CBP-DA	3	3	3	3	3	4	5	5	6	6	3	3
	CBP-DO	37	38	38	40	35	43	43	45	51	49	36	36
	AMP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**40**	**42**	**41**	**43**	**38**	**47**	**48**	**50**	**56**	**54**	**40**	**40**
SmartConnect®-enabled	SPD with Tech.	2	2	-8	33	35	45	57	57	56	43	-1	3
	SUB-TOTAL	**2**	**2**	**-8**	**33**	**35**	**45**	**57**	**57**	**56**	**43**	**-1**	**3**
Nonevent Based	RTP	0	0	0	0	0	-1	1	4	1	0	0	0
	PLS	0	0	0	0	6	6	7	7	7	6	0	0
	SUB-TOTAL	**0**	**0**	**0**	**0**	**6**	**5**	**8**	**10**	**8**	**6**	**0**	**0**
PORTFOLIO TOTAL		**590**	**602**	**592**	**718**	**798**	**857**	**921**	**942**	**904**	**822**	**628**	**595**

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Table G-11: 2027 Portfolio Aggregate Ex Ante Load Impact Estimates for 1-in-2 CAISO System Conditions

Program Type	Program	Monthly System Peak											
		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Emergency	BIP-15	117	122	122	122	129	140	141	140	140	140	135	120
	BIP-30	394	397	393	425	455	445	443	462	440	453	411	394
	AP-I	22	25	29	43	52	53	51	50	42	36	23	23
	SUB-TOTAL	**533**	**543**	**544**	**590**	**637**	**638**	**635**	**651**	**622**	**630**	**569**	**537**
Price-responsive	SDP-C	3	4	4	8	9	11	14	15	15	11	6	4
	SDP-R	0	0	0	20	47	83	128	126	116	51	2	0
	CPP-Large	8	8	8	17	17	17	16	17	17	18	9	8
	CPP-Medium	1	1	1	3	3	4	4	4	4	4	1	1
	CPP-Small	2	2	2	2	2	3	3	3	3	2	2	2
	DBP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**14**	**14**	**14**	**51**	**78**	**118**	**165**	**165**	**155**	**85**	**20**	**15**
Demand Response Aggregator-managed	CBP-DA	3	3	3	3	3	4	5	5	6	6	3	3
	CBP-DO	37	38	38	40	35	43	43	45	51	49	36	36
	AMP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**40**	**42**	**41**	**43**	**38**	**47**	**48**	**50**	**56**	**54**	**40**	**40**
SmartConnect®-enabled	SPD with Tech.	3	3	-9	35	38	49	62	62	61	46	-1	3
	SUB-TOTAL	**3**	**3**	**-9**	**35**	**38**	**49**	**62**	**62**	**61**	**46**	**-1**	**3**
Nonevent Based	RTP	0	0	0	0	0	-1	1	4	1	0	0	0
	PLS	0	0	0	0	6	6	7	7	7	6	0	0
	SUB-TOTAL	**0**	**0**	**0**	**0**	**6**	**5**	**7**	**10**	**7**	**6**	**0**	**0**
PORTFOLIO TOTAL		**590**	**602**	**591**	**719**	**797**	**855**	**917**	**939**	**901**	**821**	**627**	**594**

Appendix H Portfolio Aggregate Ex Ante Load Impact Estimates for 1-in-10 CAISO System Conditions by Month and Forecast Year

Table H-1: 2017 Portfolio Aggregate Ex Ante Load Impact Estimates for 1-in-10 CAISO System Conditions

Program Type	Program	Monthly System Peak											
		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Emergency	BIP-15	105	117	131	123	137	147	149	149	149	149	145	121
	BIP-30	435	433	434	473	515	506	495	518	499	506	460	435
	AP-I	28	25	35	48	55	55	53	55	43	44	26	26
	SUB-TOTAL	**568**	**575**	**600**	**645**	**708**	**708**	**697**	**721**	**691**	**700**	**631**	**582**
Price-responsive	SDP-C	7	9	15	29	33	32	34	39	42	34	16	7
	SDP-R	0	0	16	126	170	192	221	247	253	170	31	0
	CPP-Large	7	8	8	18	17	16	15	16	16	18	9	8
	CPP-Medium	0	0	0	0	0	0	0	0	0	0	0	0
	CPP-Small	0	0	0	0	0	0	0	0	0	0	0	0
	DBP	4	4	4	5	5	5	5	6	6	5	5	4
	SUB-TOTAL	**18**	**21**	**43**	**178**	**225**	**245**	**276**	**308**	**316**	**226**	**60**	**19**
Demand Response Aggregator-managed	CBP-DA	1	1	1	1	1	1	2	2	2	2	1	1
	CBP-DO	24	25	25	26	23	28	28	29	33	32	24	24
	AMP	83	82	82	82	80	78	77	79	77	77	83	83
	SUB-TOTAL	**108**	**108**	**109**	**109**	**104**	**107**	**107**	**110**	**112**	**111**	**108**	**108**
SmartConnect®-enabled	SPD with Tech.	1	1	0	8	9	10	11	12	13	11	0	1
	SUB-TOTAL	**1**	**1**	**0**	**8**	**9**	**10**	**11**	**12**	**13**	**11**	**0**	**1**
Nonevent Based	RTP	0	0	0	2	0	1	1	4	6	2	0	0
	PLS	0*	0*	0*	0*	0*	0*	0*	0*	0*	0*	0*	0*
	SUB-TOTAL	**0**	**0**	**0**	**2**	**0**	**1**	**1**	**4**	**6**	**2**	**0**	**0**
PORTFOLIO TOTAL		**695**	**705**	**751**	**942**	**1,045**	**1,071**	**1,091**	**1,155**	**1,138**	**1,050**	**799**	**710**

*Load impacts are redacted to protect confidential customer information

Table H-2: 2018 Portfolio Aggregate Ex Ante Load Impact Estimates for 1-in-10 CAISO System Conditions

Program Type	Program	Monthly System Peak											
		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Emergency	BIP-15	121	134	139	129	139	147	149	147	148	148	144	120
	BIP-30	435	433	432	470	509	499	488	508	490	498	451	427
	AP-I	29	26	35	49	56	56	53	55	44	45	26	26
	SUB-TOTAL	**585**	**593**	**606**	**648**	**705**	**702**	**690**	**710**	**681**	**690**	**621**	**573**
Price-responsive	SDP-C	6	8	14	27	30	30	31	36	39	31	15	7
	SDP-R	0	0	15	119	161	182	210	235	240	161	29	0
	CPP-Large	7	8	8	18	17	16	15	16	16	18	9	8
	CPP-Medium	0	0	0	0	0	0	0	0	0	4	1	1
	CPP-Small	0	0	0	0	0	0	0	0	0	1	0	0
	DBP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**14**	**16**	**37**	**165**	**209**	**228**	**257**	**287**	**295**	**215**	**55**	**16**
Demand Response Aggregator-managed	CBP-DA	3	3	3	3	3	4	5	5	6	6	3	3
	CBP-DO	37	38	39	40	35	43	43	45	51	49	36	36
	AMP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**40**	**42**	**42**	**43**	**38**	**47**	**48**	**50**	**56**	**54**	**40**	**39**
SmartConnect®-enabled	SPD with Tech.	1	1	0	15	16	17	19	20	22	19	0	2
	SUB-TOTAL	**1**	**1**	**0**	**15**	**16**	**17**	**19**	**20**	**22**	**19**	**0**	**2**
Nonevent Based	RTP	0	0	0	2	0	1	1	4	6	2	0	0
	PLS	0	0	0	0	4	4	4	4	5	4	0	0
	SUB-TOTAL	**0**	**0**	**0**	**2**	**4**	**4**	**5**	**8**	**10**	**6**	**0**	**0**
PORTFOLIO TOTAL		**641**	**652**	**685**	**872**	**972**	**998**	**1,018**	**1,076**	**1,065**	**984**	**715**	**630**

Table H-3: 2019 Portfolio Aggregate Ex Ante Load Impact Estimates for 1-in-10 CAISO System Conditions

Program Type	Program	Monthly System Peak											
		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Emergency	BIP-15	121	133	138	128	138	147	149	146	147	147	142	120
	BIP-30	426	424	424	460	497	487	476	496	478	485	440	416
	AP-I	29	26	35	49	57	56	53	55	44	45	26	26
	SUB-TOTAL	**576**	**583**	**597**	**637**	**691**	**690**	**678**	**697**	**668**	**676**	**609**	**562**
Price-responsive	SDP-C	6	8	13	25	28	28	29	34	36	29	14	6
	SDP-R	0	0	14	114	153	173	200	223	228	153	28	0
	CPP-Large	8	8	8	18	17	16	15	16	16	18	9	8
	CPP-Medium	1	1	1	4	4	4	4	4	4	10	4	3
	CPP-Small	0	0	0	1	1	1	1	1	1	6	4	4
	DBP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**15**	**17**	**37**	**161**	**203**	**222**	**249**	**278**	**285**	**216**	**58**	**21**
Demand Response Aggregator-managed	CBP-DA	3	3	3	3	3	4	5	5	6	6	3	3
	CBP-DO	37	38	39	40	35	43	43	45	51	49	36	36
	AMP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**40**	**42**	**42**	**43**	**38**	**47**	**48**	**50**	**56**	**54**	**40**	**39**
SmartConnect®-enabled	SPD with Tech.	2	2	0	19	21	21	24	25	27	23	0	2
	SUB-TOTAL	**2**	**2**	**0**	**19**	**21**	**21**	**24**	**25**	**27**	**23**	**0**	**2**
Nonevent Based	RTP	0	0	0	2	0	1	1	4	6	2	0	0
	PLS	0	0	0	0	5	5	6	6	6	5	0	0
	SUB-TOTAL	**0**	**0**	**0**	**2**	**5**	**6**	**6**	**9**	**12**	**7**	**0**	**0**
PORTFOLIO TOTAL		**632**	**643**	**676**	**862**	**958**	**986**	**1,005**	**1,060**	**1,049**	**977**	**707**	**625**

Table H-4: 2020 Portfolio Aggregate Ex Ante Load Impact Estimates for 1-in-10 CAISO System Conditions

Program Type	Program	Monthly System Peak											
		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Emergency	BIP-15	120	132	137	127	137	146	148	145	145	146	137	115
	BIP-30	416	412	413	450	487	479	467	486	468	475	431	408
	AP-I	29	26	35	49	56	56	53	55	43	45	26	26
	SUB-TOTAL	**565**	**570**	**585**	**626**	**680**	**680**	**668**	**686**	**657**	**666**	**595**	**549**
Price-responsive	SDP-C	5	7	12	23	26	25	27	31	33	27	13	6
	SDP-R	0	0	13	108	146	165	190	212	217	146	26	0
	CPP-Large	8	8	8	18	17	16	15	16	16	18	9	8
	CPP-Medium	3	3	4	9	9	10	10	11	11	4	1	1
	CPP-Small	5	4	4	6	6	7	7	8	8	3	2	2
	DBP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**20**	**22**	**41**	**164**	**204**	**223**	**250**	**278**	**285**	**197**	**51**	**16**
Demand Response Aggregator-managed	CBP-DA	3	3	3	3	3	4	5	5	6	6	3	3
	CBP-DO	37	38	39	40	35	43	43	45	51	49	36	36
	AMP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**40**	**42**	**42**	**43**	**38**	**47**	**48**	**50**	**56**	**54**	**40**	**39**
SmartConnect®-enabled	SPD with Tech.	2	2	0	23	25	26	28	31	33	28	0	2
	SUB-TOTAL	**2**	**2**	**0**	**23**	**25**	**26**	**28**	**31**	**33**	**28**	**0**	**2**
Nonevent Based	RTP	0	0	0	2	0	1	1	4	6	2	0	0
	PLS	0	0	0	0	5	6	6	6	6	6	0	0
	SUB-TOTAL	**0**	**0**	**0**	**2**	**5**	**6**	**7**	**10**	**12**	**8**	**0**	**0**
PORTFOLIO TOTAL		**628**	**636**	**669**	**858**	**953**	**982**	**1,001**	**1,054**	**1,043**	**952**	**686**	**607**

Table H-5: 2021 Portfolio Aggregate Ex Ante Load Impact Estimates for 1-in-10 CAISO System Conditions

Program Type	Program	Monthly System Peak											
		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Emergency	BIP-15	115	128	133	123	132	141	143	140	141	140	136	114
	BIP-30	407	405	406	440	479	469	458	477	460	466	423	401
	AP-I	29	25	35	49	55	55	52	54	43	44	25	25
	SUB-TOTAL	**551**	**559**	**573**	**612**	**666**	**665**	**653**	**671**	**643**	**649**	**584**	**540**
Price-responsive	SDP-C	5	6	11	21	24	23	25	29	30	25	12	5
	SDP-R	0	0	13	103	139	156	181	202	206	138	25	0
	CPP-Large	8	8	8	18	17	16	15	16	16	18	9	8
	CPP-Medium	1	1	1	4	4	4	4	4	4	4	1	1
	CPP-Small	2	2	2	2	3	3	3	3	3	3	2	2
	DBP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**15**	**17**	**35**	**148**	**186**	**203**	**228**	**254**	**260**	**187**	**49**	**16**
Demand Response Aggregator-managed	CBP-DA	3	3	3	3	3	4	5	5	6	6	3	3
	CBP-DO	37	38	39	40	35	43	43	45	51	49	36	36
	AMP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**40**	**42**	**42**	**43**	**38**	**47**	**48**	**50**	**56**	**54**	**40**	**39**
SmartConnect®-enabled	SPD with Tech.	2	2	0	27	30	30	33	36	38	32	1	3
	SUB-TOTAL	**2**	**2**	**0**	**27**	**30**	**30**	**33**	**36**	**38**	**32**	**1**	**3**
Nonevent Based	RTP	0	0	0	2	0	1	1	4	6	2	0	0
	PLS	0	0	0	0	6	6	7	7	7	6	0	0
	SUB-TOTAL	**0**	**0**	**0**	**2**	**6**	**7**	**7**	**10**	**13**	**8**	**0**	**0**
PORTFOLIO TOTAL		**609**	**620**	**650**	**832**	**926**	**952**	**969**	**1,021**	**1,011**	**931**	**673**	**598**

Table H-6: 2022 Portfolio Aggregate Ex Ante Load Impact Estimates for 1-in-10 CAISO System Conditions

Program Type	Program	Monthly System Peak											
		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Emergency	BIP-15	114	127	131	121	130	140	141	140	140	140	136	114
	BIP-30	400	398	398	431	469	461	449	468	452	459	418	396
	AP-I	28	25	34	48	55	54	51	53	42	43	25	25
	SUB-TOTAL	**542**	**550**	**563**	**600**	**654**	**654**	**642**	**661**	**634**	**642**	**578**	**535**
Price-responsive	SDP-C	4	6	10	20	22	22	23	26	28	23	11	5
	SDP-R	0	0	12	98	132	149	172	192	196	132	24	0
	CPP-Large	8	8	8	18	17	16	16	16	16	18	9	8
	CPP-Medium	1	1	1	4	4	4	4	4	4	4	1	1
	CPP-Small	2	2	2	2	3	3	3	3	3	3	2	2
	DBP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**15**	**17**	**34**	**141**	**177**	**193**	**217**	**242**	**248**	**179**	**47**	**15**
Demand Response Aggregator-managed	CBP-DA	3	3	3	3	3	4	5	5	6	6	3	3
	CBP-DO	37	38	39	40	35	43	43	45	51	49	36	36
	AMP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**40**	**42**	**42**	**43**	**38**	**47**	**48**	**50**	**56**	**54**	**40**	**39**
SmartConnect®-enabled	SPD with Tech.	3	3	0	31	34	35	38	41	44	37	1	3
	SUB-TOTAL	**3**	**3**	**0**	**31**	**34**	**35**	**38**	**41**	**44**	**37**	**1**	**3**
Nonevent Based	RTP	0	0	0	2	0	1	1	4	6	2	0	0
	PLS	0	0	0	0	6	6	7	7	7	7	0	0
	SUB-TOTAL	**0**	**0**	**0**	**2**	**6**	**7**	**7**	**11**	**13**	**8**	**0**	**0**
PORTFOLIO TOTAL		**600**	**611**	**639**	**818**	**909**	**936**	**952**	**1,004**	**995**	**920**	**665**	**593**

Table H-7: 2023 Portfolio Aggregate Ex Ante Load Impact Estimates for 1-in-10 CAISO System Conditions

Program Type	Program	Monthly System Peak											
		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Emergency	BIP-15	114	127	131	121	130	140	141	140	140	140	136	114
	BIP-30	396	394	395	429	467	459	449	468	452	459	418	396
	AP-I	28	25	34	48	54	54	51	53	42	43	25	25
	SUB-TOTAL	**538**	**545**	**560**	**598**	**652**	**652**	**642**	**661**	**634**	**642**	**578**	**535**
Price-responsive	SDP-C	4	5	9	18	20	20	21	24	26	21	10	4
	SDP-R	0	0	11	93	125	141	163	182	186	125	23	0
	CPP-Large	8	8	8	18	17	16	16	16	17	18	9	8
	CPP-Medium	1	1	1	4	4	4	4	4	4	4	1	1
	CPP-Small	2	2	2	2	3	3	3	3	3	3	2	2
	DBP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**15**	**16**	**32**	**135**	**169**	**184**	**207**	**230**	**236**	**170**	**44**	**15**
Demand Response Aggregator-managed	CBP-DA	3	3	3	3	3	4	5	5	6	6	3	3
	CBP-DO	37	38	39	40	35	43	43	45	51	49	36	36
	AMP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**40**	**42**	**42**	**43**	**38**	**47**	**48**	**50**	**56**	**54**	**40**	**39**
SmartConnect®-enabled	SPD with Tech.	3	3	0	35	38	40	43	46	49	41	1	3
	SUB-TOTAL	**3**	**3**	**0**	**35**	**38**	**40**	**43**	**46**	**49**	**41**	**1**	**3**
Nonevent Based	RTP	0	0	0	2	0	1	1	4	6	2	0	0
	PLS	0	0	0	0	6	7	7	8	8	7	0	0
	SUB-TOTAL	**0**	**0**	**0**	**2**	**7**	**7**	**8**	**11**	**13**	**9**	**0**	**0**
PORTFOLIO TOTAL		**596**	**607**	**634**	**814**	**904**	**930**	**947**	**998**	**989**	**917**	**663**	**593**

Table H-8: 2024 Portfolio Aggregate Ex Ante Load Impact Estimates for 1-in-10 CAISO System Conditions

Program Type	Program	Monthly System Peak											
		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Emergency	BIP-15	114	127	131	121	130	140	141	140	140	140	136	114
	BIP-30	396	394	395	429	467	459	449	468	452	459	418	396
	AP-I	28	25	34	48	54	54	51	53	42	43	25	25
	SUB-TOTAL	**538**	**545**	**560**	**598**	**652**	**652**	**642**	**661**	**634**	**642**	**578**	**535**
Price-responsive	SDP-C	4	5	8	17	18	18	19	22	24	19	9	4
	SDP-R	0	0	11	88	119	134	155	173	177	119	22	0
	CPP-Large	8	8	8	18	17	16	16	16	17	18	9	8
	CPP-Medium	1	1	1	4	4	4	4	4	4	4	1	1
	CPP-Small	2	2	2	2	3	3	3	3	3	3	2	2
	DBP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**14**	**16**	**31**	**129**	**161**	**175**	**197**	**219**	**224**	**162**	**43**	**15**
Demand Response Aggregator-managed	CBP-DA	3	3	3	3	3	4	5	5	6	6	3	3
	CBP-DO	37	38	39	40	35	43	43	45	51	49	36	36
	AMP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**40**	**42**	**42**	**43**	**38**	**47**	**48**	**50**	**56**	**54**	**40**	**39**
SmartConnect®-enabled	SPD with Tech.	3	3	0	40	43	44	48	51	55	46	1	4
	SUB-TOTAL	**3**	**3**	**0**	**40**	**43**	**44**	**48**	**51**	**55**	**46**	**1**	**4**
Nonevent Based	RTP	0	0	0	2	0	1	1	4	6	2	0	0
	PLS	0	0	0	0	7	7	7	8	8	7	0	0
	SUB-TOTAL	**0**	**0**	**0**	**2**	**7**	**7**	**8**	**11**	**14**	**9**	**0**	**0**
PORTFOLIO TOTAL		**596**	**607**	**633**	**812**	**900**	**926**	**942**	**992**	**983**	**914**	**661**	**593**

Table H-9: 2025 Portfolio Aggregate Ex Ante Load Impact Estimates for 1-in-10 CAISO System Conditions

Program Type	Program	Monthly System Peak											
		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Emergency	BIP-15	114	127	131	121	130	140	141	140	140	140	136	114
	BIP-30	396	394	395	429	467	459	449	468	452	459	418	396
	AP-I	28	25	34	48	54	54	51	53	42	43	25	25
	SUB-TOTAL	**538**	**545**	**560**	**598**	**652**	**652**	**642**	**661**	**634**	**642**	**578**	**535**
Price-responsive	SDP-C	3	5	8	15	17	17	17	20	22	17	8	4
	SDP-R	0	0	10	84	113	127	147	164	168	113	20	0
	CPP-Large	8	8	8	18	17	16	16	16	17	18	9	8
	CPP-Medium	1	1	1	4	4	4	4	4	4	4	1	1
	CPP-Small	2	2	2	2	3	3	3	3	3	3	2	2
	DBP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**14**	**15**	**30**	**123**	**153**	**167**	**187**	**208**	**213**	**155**	**41**	**14**
Demand Response Aggregator-managed	CBP-DA	3	3	3	3	3	4	5	5	6	6	3	3
	CBP-DO	37	38	39	40	35	43	43	45	51	49	36	36
	AMP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**40**	**42**	**42**	**43**	**38**	**47**	**48**	**50**	**56**	**54**	**40**	**39**
SmartConnect®-enabled	SPD with Tech.	4	4	0	44	47	49	53	57	60	51	1	4
	SUB-TOTAL	**4**	**4**	**0**	**44**	**47**	**49**	**53**	**57**	**60**	**51**	**1**	**4**
Nonevent Based	RTP	0	0	0	2	0	1	1	4	6	2	0	0
	PLS	0	0	0	0	6	7	7	7	8	7	0	0
	SUB-TOTAL	**0**	**0**	**0**	**2**	**6**	**7**	**8**	**11**	**13**	**9**	**0**	**0**
PORTFOLIO TOTAL		**596**	**607**	**631**	**810**	**897**	**922**	**937**	**987**	**977**	**910**	**660**	**593**

Table H-10: 2026 Portfolio Aggregate Ex Ante Load Impact Estimates for 1-in-10 CAISO System Conditions

Program Type	Program	Monthly System Peak											
		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Emergency	BIP-15	114	127	131	121	130	140	141	140	140	140	136	114
	BIP-30	396	394	395	429	467	459	449	468	452	459	418	396
	AP-I	28	25	34	48	54	54	51	53	42	43	25	25
	SUB-TOTAL	**538**	**545**	**560**	**598**	**652**	**652**	**642**	**661**	**634**	**642**	**578**	**535**
Price-responsive	SDP-C	3	4	7	14	15	15	16	18	20	16	8	3
	SDP-R	0	0	10	79	107	121	139	156	159	107	19	0
	CPP-Large	8	8	8	18	17	16	16	16	17	18	9	8
	CPP-Medium	1	1	1	4	4	4	4	4	4	4	1	1
	CPP-Small	2	2	2	2	3	3	3	3	3	3	2	2
	DBP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**14**	**15**	**28**	**117**	**146**	**159**	**178**	**198**	**203**	**147**	**39**	**14**
Demand Response Aggregator-managed	CBP-DA	3	3	3	3	3	4	5	5	6	6	3	3
	CBP-DO	37	38	39	40	35	43	43	45	51	49	36	36
	AMP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**40**	**42**	**42**	**43**	**38**	**47**	**48**	**50**	**56**	**54**	**40**	**39**
SmartConnect®-enabled	SPD with Tech.	4	4	0	48	52	53	58	62	66	55	1	5
	SUB-TOTAL	**4**	**4**	**0**	**48**	**52**	**53**	**58**	**62**	**66**	**55**	**1**	**5**
Nonevent Based	RTP	0	0	0	2	0	1	1	4	6	2	0	0
	PLS	0	0	0	0	6	6	7	7	7	7	0	0
	SUB-TOTAL	**0**	**0**	**0**	**2**	**6**	**7**	**8**	**11**	**13**	**8**	**0**	**0**
PORTFOLIO TOTAL		**596**	**607**	**630**	**808**	**894**	**918**	**933**	**981**	**972**	**908**	**658**	**593**

Table H-11: 2027 Portfolio Aggregate Ex Ante Load Impact Estimates for 1-in-10 CAISO System Conditions

Program Type	Program	Monthly System Peak											
		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Emergency	BIP-15	114	127	131	121	130	140	141	140	140	140	136	114
	BIP-30	396	394	395	429	467	459	449	468	452	459	418	396
	AP-I	28	25	34	48	54	54	51	53	42	43	25	25
	SUB-TOTAL	**538**	**545**	**560**	**598**	**652**	**652**	**642**	**661**	**634**	**642**	**578**	**535**
Price-responsive	SDP-C	3	4	6	13	14	14	14	17	18	14	7	3
	SDP-R	0	0	9	75	102	115	132	148	151	101	18	0
	CPP-Large	8	8	8	18	17	16	16	16	17	18	9	8
	CPP-Medium	1	1	1	4	4	4	4	4	4	4	1	1
	CPP-Small	2	2	2	2	3	3	3	3	3	3	2	2
	DBP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**14**	**15**	**27**	**112**	**139**	**151**	**170**	**188**	**193**	**140**	**37**	**14**
Demand Response Aggregator -managed	CBP-DA	3	3	3	3	3	4	5	5	6	6	3	3
	CBP-DO	37	38	39	40	35	43	43	45	51	49	36	36
	AMP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**40**	**42**	**42**	**43**	**38**	**47**	**48**	**50**	**56**	**54**	**40**	**39**
SmartConnect®-enabled	SPD with Tech.	5	5	0	52	56	58	63	67	71	60	1	5
	SUB-TOTAL	**5**	**5**	**0**	**52**	**56**	**58**	**63**	**67**	**71**	**60**	**1**	**5**
Nonevent Based	RTP	0	0	0	2	0	1	1	4	6	2	0	0
	PLS	0	0	0	0	6	6	7	7	7	6	0	0
	SUB-TOTAL	**0**	**0**	**0**	**2**	**6**	**7**	**7**	**11**	**13**	**8**	**0**	**0**
PORTFOLIO TOTAL		**596**	**607**	**629**	**807**	**891**	**915**	**929**	**977**	**968**	**905**	**656**	**593**

Appendix I Program-specific Aggregate Ex Ante Load Impact Estimates for 1-in-2 CAISO System Conditions by Month and Forecast Year

Table I-1: 2017 Program-specific Aggregate Ex Ante Load Impact Estimates for 1-in-2 CAISO System Conditions

Program Type	Program	Monthly System Peak											
		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Emergency	BIP-15	108	112	122	124	136	147	149	149	149	149	144	128
	BIP-30	432	437	433	469	502	490	489	511	486	500	453	433
	AP-I	22	25	30	43	53	54	52	51	43	37	24	24
	SUB-TOTAL	**562**	**574**	**584**	**636**	**691**	**692**	**690**	**711**	**677**	**686**	**621**	**584**
Price-responsive	SDP-C	8	8	9	19	22	27	34	36	35	25	14	9
	SDP-R	0	0	0	33	78	140	214	211	193	85	4	0
	CPP-Large	14	14	14	31	31	30	29	31	31	33	15	14
	CPP-Medium	0	0	0	0	0	0	0	0	0	0	0	0
	CPP-Small	0	0	0	0	0	0	0	0	0	0	0	0
	DBP	51	51	52	52	61	101	101	103	99	62	59	48
	SUB-TOTAL	**73**	**73**	**74**	**136**	**192**	**298**	**377**	**379**	**359**	**204**	**92**	**71**
Demand Response Aggregator-managed	CBP-DA	1	1	1	1	1	1	2	2	2	2	1	1
	CBP-DO	24	25	25	26	23	28	28	29	33	32	24	24
	AMP	83	82	82	82	80	78	77	79	77	77	83	83
	SUB-TOTAL	**108**	**108**	**108**	**109**	**104**	**107**	**107**	**110**	**112**	**111**	**108**	**108**
SmartConnect®-enabled	SPD with Tech.	0	0	-2	7	8	10	13	14	14	11	0	1
	SUB-TOTAL	**0**	**0**	**-2**	**7**	**8**	**10**	**13**	**14**	**14**	**11**	**0**	**1**
Nonevent Based	RTP	1	1	1	0	0	-7	2	17	2	0	1	1
	PLS	0*	0*	0*	0*	0*	0*	0*	0*	0*	0*	0*	0*
	SUB-TOTAL	**1**	**1**	**1**	**0**	**0**	**-7**	**2**	**17**	**2**	**0**	**1**	**1**
PORTFOLIO TOTAL		**745**	**757**	**765**	**887**	**995**	**1,100**	**1,190**	**1,230**	**1,164**	**1,012**	**821**	**764**

*Load impacts are redacted to protect confidential customer information

Table I-2: 2018 Program-specific Aggregate Ex Ante Load Impact Estimates for 1-in-2 CAISO System Conditions

Program Type	Program	Monthly System Peak											
		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Emergency	BIP-15	125	129	129	130	138	147	149	147	148	148	143	127
	BIP-30	433	436	430	465	496	484	482	501	477	491	445	425
	AP-I	23	25	30	44	54	55	53	51	43	38	24	24
	SUB-TOTAL	**580**	**591**	**589**	**639**	**688**	**686**	**683**	**700**	**667**	**677**	**611**	**576**
Price-responsive	SDP-C	7	8	8	18	20	25	31	33	33	23	13	8
	SDP-R	0	0	0	32	74	133	203	200	184	80	4	0
	CPP-Large	14	14	14	31	31	30	29	31	32	33	15	15
	CPP-Medium	0	0	0	0	0	0	0	0	0	3	1	1
	CPP-Small	0	0	0	0	0	0	0	0	0	1	0	0
	DBP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**21**	**22**	**22**	**81**	**125**	**188**	**263**	**264**	**248**	**141**	**34**	**25**
Demand Response Aggregator-managed	CBP-DA	3	3	3	3	3	4	5	5	6	6	3	3
	CBP-DO	37	38	38	40	35	43	43	45	51	49	36	36
	AMP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**40**	**42**	**41**	**43**	**38**	**47**	**48**	**50**	**56**	**54**	**40**	**40**
SmartConnect®-enabled	SPD with Tech.	1	1	-2	10	11	14	18	19	19	14	0	1
	SUB-TOTAL	**1**	**1**	**-2**	**10**	**11**	**14**	**18**	**19**	**19**	**14**	**0**	**1**
Nonevent Based	RTP	1	1	1	0	0	-7	2	17	2	0	1	1
	PLS	0	0	0	0	3	4	4	4	4	4	0	0
	SUB-TOTAL	**1**	**1**	**1**	**0**	**3**	**-3**	**6**	**21**	**7**	**4**	**1**	**1**
PORTFOLIO TOTAL		**643**	**656**	**651**	**774**	**866**	**932**	**1,019**	**1,053**	**997**	**890**	**685**	**642**

Table I-3: 2019 Program-specific Aggregate Ex Ante Load Impact Estimates for 1-in-2 CAISO System Conditions

Program Type	Program	Monthly System Peak											
		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Emergency	BIP-15	124	128	128	129	137	147	149	146	147	147	141	126
	BIP-30	424	427	422	455	484	472	469	489	465	478	434	414
	AP-I	23	26	30	44	55	55	53	52	43	38	24	24
	SUB-TOTAL	**570**	**581**	**581**	**629**	**675**	**674**	**672**	**687**	**655**	**663**	**599**	**564**
Price-responsive	SDP-C	7	7	7	16	19	23	29	31	30	21	12	8
	SDP-R	0	0	0	30	70	126	193	190	175	77	4	0
	CPP-Large	14	14	14	31	31	30	29	31	32	33	15	15
	CPP-Medium	1	1	1	3	3	4	4	4	4	9	3	3
	CPP-Small	0	0	0	1	1	1	1	1	1	6	4	4
	DBP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**22**	**23**	**23**	**81**	**124**	**184**	**256**	**256**	**241**	**145**	**39**	**30**
Demand Response Aggregator-managed	CBP-DA	3	3	3	3	3	4	5	5	6	6	3	3
	CBP-DO	37	38	38	40	35	43	43	45	51	49	36	36
	AMP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**40**	**42**	**41**	**43**	**38**	**47**	**48**	**50**	**56**	**54**	**40**	**40**
SmartConnect®-enabled	SPD with Tech.	1	1	-3	13	14	18	23	24	24	18	-1	1
	SUB-TOTAL	**1**	**1**	**-3**	**13**	**14**	**18**	**23**	**24**	**24**	**18**	**-1**	**1**
Nonevent Based	RTP	1	1	1	0	0	-7	2	17	2	0	1	1
	PLS	0	0	0	0	4	5	6	5	6	5	0	0
	SUB-TOTAL	**1**	**1**	**1**	**0**	**5**	**-2**	**8**	**22**	**8**	**5**	**1**	**1**
PORTFOLIO TOTAL		**635**	**647**	**642**	**767**	**856**	**921**	**1,006**	**1,039**	**984**	**886**	**677**	**635**

Table I-4: 2020 Program-specific Aggregate Ex Ante Load Impact Estimates for 1-in-2 CAISO System Conditions

Program Type	Program	Monthly System Peak											
		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Emergency	BIP-15	123	127	127	128	136	146	148	145	145	146	136	122
	BIP-30	414	415	412	445	474	464	461	479	456	469	425	406
	AP-I	23	26	30	44	54	55	53	51	43	37	24	24
	SUB-TOTAL	**560**	**568**	**569**	**618**	**665**	**665**	**662**	**676**	**644**	**653**	**585**	**551**
Price-responsive	SDP-C	6	7	7	15	17	21	27	28	28	20	11	7
	SDP-R	0	0	0	29	67	120	184	181	166	73	3	0
	CPP-Large	14	14	14	31	31	30	29	31	32	33	15	15
	CPP-Medium	3	3	3	8	8	9	10	10	10	4	1	1
	CPP-Small	4	4	4	5	5	6	7	7	7	2	2	2
	DBP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**28**	**28**	**28**	**88**	**129**	**187**	**257**	**258**	**242**	**131**	**33**	**25**
Demand Response Aggregator-managed	CBP-DA	3	3	3	3	3	4	5	5	6	6	3	3
	CBP-DO	37	38	38	40	35	43	43	45	51	49	36	36
	AMP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**40**	**42**	**41**	**43**	**38**	**47**	**48**	**50**	**56**	**54**	**40**	**40**
SmartConnect®-enabled	SPD with Tech.	1	1	-4	16	17	22	28	28	28	21	-1	1
	SUB-TOTAL	**1**	**1**	**-4**	**16**	**17**	**22**	**28**	**28**	**28**	**21**	**-1**	**1**
Nonevent Based	RTP	1	1	1	0	0	-7	2	17	2	0	1	1
	PLS	0	0	0	0	5	5	6	6	6	5	0	0
	SUB-TOTAL	**1**	**1**	**1**	**0**	**5**	**-1**	**8**	**22**	**9**	**5**	**1**	**1**
PORTFOLIO TOTAL		**629**	**640**	**635**	**765**	**854**	**919**	**1,003**	**1,034**	**979**	**865**	**657**	**618**

Table I-5: 2021 Program-specific Aggregate Ex Ante Load Impact Estimates for 1-in-2 CAISO System Conditions

Program Type	Program	Monthly System Peak											
		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Emergency	BIP-15	119	123	123	124	131	141	143	140	141	140	135	120
	BIP-30	405	408	404	436	466	455	452	470	447	460	417	399
	AP-I	23	25	30	44	54	54	52	51	42	37	23	23
	SUB-TOTAL	**546**	**557**	**558**	**603**	**651**	**650**	**647**	**661**	**630**	**637**	**575**	**542**
Price-responsive	SDP-C	6	6	6	14	16	19	24	26	26	18	10	7
	SDP-R	0	0	0	27	64	114	175	172	158	69	3	0
	CPP-Large	14	14	14	31	31	31	29	31	32	33	16	15
	CPP-Medium	1	1	1	3	3	4	4	4	4	4	1	1
	CPP-Small	2	2	2	2	2	3	3	3	3	2	2	2
	DBP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**23**	**23**	**23**	**78**	**116**	**170**	**235**	**236**	**222**	**126**	**32**	**24**
Demand Response Aggregator-managed	CBP-DA	3	3	3	3	3	4	5	5	6	6	3	3
	CBP-DO	37	38	38	40	35	43	43	45	51	49	36	36
	AMP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**40**	**42**	**41**	**43**	**38**	**47**	**48**	**50**	**56**	**54**	**40**	**40**
SmartConnect®-enabled	SPD with Tech.	1	1	-5	19	20	26	33	33	33	25	-1	2
	SUB-TOTAL	**1**	**1**	**-5**	**19**	**20**	**26**	**33**	**33**	**33**	**25**	**-1**	**2**
Nonevent Based	RTP	1	1	1	0	0	-7	2	17	2	0	1	1
	PLS	0	0	0	0	5	6	7	6	7	6	0	0
	SUB-TOTAL	**1**	**1**	**1**	**0**	**5**	**-1**	**9**	**23**	**9**	**6**	**1**	**1**
PORTFOLIO TOTAL		**611**	**624**	**618**	**743**	**830**	**892**	**971**	**1,003**	**951**	**848**	**646**	**608**

Table I-6: 2022 Program-specific Aggregate Ex Ante Load Impact Estimates for 1-in-2 CAISO System Conditions

Program Type	Program	Monthly System Peak											
		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Emergency	BIP-15	117	122	122	122	129	140	141	140	140	140	135	120
	BIP-30	397	401	397	427	457	447	443	462	440	453	411	394
	AP-I	22	25	30	43	53	53	51	50	42	36	23	23
	SUB-TOTAL	**537**	**547**	**548**	**592**	**639**	**639**	**635**	**651**	**622**	**630**	**569**	**537**
Price-responsive	SDP-C	5	6	6	13	15	18	22	24	24	17	9	6
	SDP-R	0	0	0	26	61	108	166	163	150	66	3	0
	CPP-Large	14	14	14	31	31	31	29	31	32	33	16	15
	CPP-Medium	1	1	1	3	3	4	4	4	4	4	1	1
	CPP-Small	2	2	2	2	2	3	3	3	3	2	2	2
	DBP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**22**	**23**	**23**	**75**	**112**	**163**	**225**	**225**	**212**	**122**	**31**	**24**
Demand Response Aggregator-managed	CBP-DA	3	3	3	3	3	4	5	5	6	6	3	3
	CBP-DO	37	38	38	40	35	43	43	45	51	49	36	36
	AMP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**40**	**42**	**41**	**43**	**38**	**47**	**48**	**50**	**56**	**54**	**40**	**40**
SmartConnect®-enabled	SPD with Tech.	2	2	-5	21	23	29	38	38	38	29	-1	2
	SUB-TOTAL	**2**	**2**	**-5**	**21**	**23**	**29**	**38**	**38**	**38**	**29**	**-1**	**2**
Nonevent Based	RTP	1	1	1	0	0	-7	2	17	2	0	1	1
	PLS	0	0	0	0	6	6	7	7	7	6	0	0
	SUB-TOTAL	**1**	**1**	**1**	**0**	**6**	**-1**	**9**	**23**	**9**	**6**	**1**	**1**
PORTFOLIO TOTAL		**602**	**614**	**607**	**732**	**818**	**878**	**954**	**988**	**937**	**840**	**639**	**603**

Table I-7: 2023 Program-specific Aggregate Ex Ante Load Impact Estimates for 1-in-2 CAISO System Conditions

Program Type	Program	Monthly System Peak											
		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Emergency	BIP-15	117	122	122	122	129	140	141	140	140	140	135	120
	BIP-30	394	397	393	425	455	445	443	462	440	453	411	394
	AP-I	22	25	29	43	52	53	51	50	42	36	23	23
	SUB-TOTAL	**533**	**543**	**544**	**590**	**637**	**638**	**635**	**651**	**622**	**630**	**569**	**537**
Price-responsive	SDP-C	5	5	5	12	13	16	21	22	22	15	8	6
	SDP-R	0	0	0	25	58	103	158	155	143	62	3	0
	CPP-Large	14	14	14	31	31	31	29	31	32	34	16	15
	CPP-Medium	1	1	1	3	3	4	4	4	4	4	1	1
	CPP-Small	2	2	2	2	2	3	3	3	3	2	2	2
	DBP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**22**	**22**	**22**	**73**	**108**	**156**	**215**	**215**	**203**	**117**	**30**	**23**
Demand Response Aggregator-managed	CBP-DA	3	3	3	3	3	4	5	5	6	6	3	3
	CBP-DO	37	38	38	40	35	43	43	45	51	49	36	36
	AMP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**40**	**42**	**41**	**43**	**38**	**47**	**48**	**50**	**56**	**54**	**40**	**40**
SmartConnect®-enabled	SPD with Tech.	2	2	-6	24	26	33	42	43	42	32	-1	2
	SUB-TOTAL	**2**	**2**	**-6**	**24**	**26**	**33**	**42**	**43**	**42**	**32**	**-1**	**2**
Nonevent Based	RTP	1	1	1	0	0	-7	2	17	2	0	1	1
	PLS	0	0	0	0	6	6	7	7	7	6	0	0
	SUB-TOTAL	**1**	**1**	**1**	**0**	**6**	**0**	**10**	**24**	**10**	**6**	**1**	**1**
PORTFOLIO TOTAL		**597**	**610**	**602**	**731**	**815**	**874**	**950**	**983**	**933**	**840**	**638**	**602**

Table I-8: 2024 Program-specific Aggregate Ex Ante Load Impact Estimates for 1-in-2 CAISO System Conditions

Program Type	Program	Monthly System Peak											
		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Emergency	BIP-15	117	122	122	122	129	140	141	140	140	140	135	120
	BIP-30	394	397	393	425	455	445	443	462	440	453	411	394
	AP-I	22	25	29	43	52	53	51	50	42	36	23	23
	SUB-TOTAL	**533**	**543**	**544**	**590**	**637**	**638**	**635**	**651**	**622**	**630**	**569**	**537**
Price-responsive	SDP-C	4	5	5	11	12	15	19	20	20	14	8	5
	SDP-R	0	0	0	23	55	98	150	147	135	59	3	0
	CPP-Large	14	14	14	31	31	31	29	31	32	34	16	15
	CPP-Medium	1	1	1	3	3	4	4	4	4	4	1	1
	CPP-Small	2	2	2	2	2	3	3	3	3	2	2	2
	DBP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**22**	**22**	**22**	**71**	**104**	**150**	**205**	**206**	**194**	**113**	**29**	**23**
Demand Response Aggregator-managed	CBP-DA	3	3	3	3	3	4	5	5	6	6	3	3
	CBP-DO	37	38	38	40	35	43	43	45	51	49	36	36
	AMP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**40**	**42**	**41**	**43**	**38**	**47**	**48**	**50**	**56**	**54**	**40**	**40**
SmartConnect®-enabled	SPD with Tech.	2	2	-7	27	29	37	47	48	47	36	-1	2
	SUB-TOTAL	**2**	**2**	**-7**	**27**	**29**	**37**	**47**	**48**	**47**	**36**	**-1**	**2**
Nonevent Based	RTP	1	1	1	0	0	-7	2	17	2	0	1	1
	PLS	0	0	0	0	6	6	7	7	7	6	0	0
	SUB-TOTAL	**1**	**1**	**1**	**0**	**6**	**0**	**10**	**24**	**10**	**7**	**1**	**1**
PORTFOLIO TOTAL		**597**	**610**	**601**	**731**	**814**	**871**	**945**	**978**	**929**	**839**	**637**	**602**

Table I-9: 2025 Program-specific Aggregate Ex Ante Load Impact Estimates for 1-in-2 CAISO System Conditions

Program Type	Program	Monthly System Peak											
		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Emergency	BIP-15	117	122	122	122	129	140	141	140	140	140	135	120
	BIP-30	394	397	393	425	455	445	443	462	440	453	411	394
	AP-I	22	25	29	43	52	53	51	50	42	36	23	23
	SUB-TOTAL	**533**	**543**	**544**	**590**	**637**	**638**	**635**	**651**	**622**	**630**	**569**	**537**
Price-responsive	SDP-C	4	4	4	10	11	14	17	18	18	13	7	5
	SDP-R	0	0	0	22	52	93	142	140	128	56	3	0
	CPP-Large	14	14	14	32	31	31	30	31	32	34	16	15
	CPP-Medium	1	1	1	3	3	4	4	4	4	4	1	1
	CPP-Small	2	2	2	2	2	3	3	3	3	2	2	2
	DBP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**21**	**22**	**22**	**69**	**100**	**144**	**196**	**197**	**186**	**109**	**29**	**23**
Demand Response Aggregator-managed	CBP-DA	3	3	3	3	3	4	5	5	6	6	3	3
	CBP-DO	37	38	38	40	35	43	43	45	51	49	36	36
	AMP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**40**	**42**	**41**	**43**	**38**	**47**	**48**	**50**	**56**	**54**	**40**	**40**
SmartConnect®-enabled	SPD with Tech.	2	2	-7	30	32	41	52	53	52	39	-1	2
	SUB-TOTAL	**2**	**2**	**-7**	**30**	**32**	**41**	**52**	**53**	**52**	**39**	**-1**	**2**
Nonevent Based	RTP	1	1	1	0	0	-7	2	17	2	0	1	1
	PLS	0	0	0	0	6	6	7	7	7	6	0	0
	SUB-TOTAL	**1**	**1**	**1**	**0**	**6**	**0**	**10**	**23**	**10**	**6**	**1**	**1**
PORTFOLIO TOTAL		**597**	**610**	**600**	**732**	**813**	**869**	**940**	**974**	**925**	**838**	**637**	**602**

Table I-10: 2026 Program-specific Aggregate Ex Ante Load Impact Estimates for 1-in-2 CAISO System Conditions

Program Type	Program	Monthly System Peak											
		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Emergency	BIP-15	117	122	122	122	129	140	141	140	140	140	135	120
	BIP-30	394	397	393	425	455	445	443	462	440	453	411	394
	AP-I	22	25	29	43	52	53	51	50	42	36	23	23
	SUB-TOTAL	**533**	**543**	**544**	**590**	**637**	**638**	**635**	**651**	**622**	**630**	**569**	**537**
Price-responsive	SDP-C	4	4	4	9	10	13	16	17	17	12	6	4
	SDP-R	0	0	0	21	49	88	135	133	122	53	3	0
	CPP-Large	14	15	14	32	31	31	30	31	32	34	16	15
	CPP-Medium	1	1	1	3	3	4	4	4	4	4	1	1
	CPP-Small	2	2	2	2	2	3	3	3	3	2	2	2
	DBP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**21**	**21**	**21**	**67**	**96**	**138**	**187**	**188**	**178**	**105**	**28**	**22**
Demand Response Aggregator-managed	CBP-DA	3	3	3	3	3	4	5	5	6	6	3	3
	CBP-DO	37	38	38	40	35	43	43	45	51	49	36	36
	AMP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**40**	**42**	**41**	**43**	**38**	**47**	**48**	**50**	**56**	**54**	**40**	**40**
SmartConnect®-enabled	SPD with Tech.	2	2	-8	33	35	45	57	57	56	43	-1	3
	SUB-TOTAL	**2**	**2**	**-8**	**33**	**35**	**45**	**57**	**57**	**56**	**43**	**-1**	**3**
Nonevent Based	RTP	1	1	1	0	0	-7	2	17	2	0	1	1
	PLS	0	0	0	0	6	6	7	7	7	6	0	0
	SUB-TOTAL	**1**	**1**	**1**	**0**	**6**	**-1**	**9**	**23**	**9**	**6**	**1**	**1**
PORTFOLIO TOTAL		**597**	**609**	**599**	**733**	**813**	**866**	**936**	**970**	**921**	**838**	**636**	**602**

Table I-11: 2027 Program-specific Aggregate Ex Ante Load Impact Estimates for 1-in-2 CAISO System Conditions

Program Type	Program	Monthly System Peak											
		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Emergency	BIP-15	117	122	122	122	129	140	141	140	140	140	135	120
	BIP-30	394	397	393	425	455	445	443	462	440	453	411	394
	AP-I	22	25	29	43	52	53	51	50	42	36	23	23
	SUB-TOTAL	**533**	**543**	**544**	**590**	**637**	**638**	**635**	**651**	**622**	**630**	**569**	**537**
Price-responsive	SDP-C	3	4	4	8	9	11	14	15	15	11	6	4
	SDP-R	0	0	0	20	47	83	128	126	116	51	2	0
	CPP-Large	14	15	14	32	31	31	30	32	32	34	16	15
	CPP-Medium	1	1	1	3	3	4	4	4	4	4	1	1
	CPP-Small	2	2	2	2	2	3	3	3	3	2	2	2
	DBP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**21**	**21**	**21**	**65**	**93**	**132**	**179**	**180**	**170**	**101**	**27**	**22**
Demand Response Aggregator-managed	CBP-DA	3	3	3	3	3	4	5	5	6	6	3	3
	CBP-DO	37	38	38	40	35	43	43	45	51	49	36	36
	AMP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**40**	**42**	**41**	**43**	**38**	**47**	**48**	**50**	**56**	**54**	**40**	**40**
SmartConnect®-enabled	SPD with Tech.	3	3	-9	35	38	49	62	62	61	46	-1	3
	SUB-TOTAL	**3**	**3**	**-9**	**35**	**38**	**49**	**62**	**62**	**61**	**46**	**-1**	**3**
Nonevent Based	RTP	1	1	1	0	0	-7	2	17	2	0	1	1
	PLS	0	0	0	0	6	6	7	7	7	6	0	0
	SUB-TOTAL	**1**	**1**	**1**	**0**	**6**	**-1**	**9**	**23**	**9**	**6**	**1**	**1**
PORTFOLIO TOTAL		**597**	**609**	**598**	**734**	**812**	**864**	**933**	**966**	**918**	**837**	**635**	**602**

Appendix J Program-specific Ex Ante Load Impact Estimates for 1-in-10 CAISO System Conditions by Month and Forecast Year

Table J-1: 2017 Program-specific Aggregate Ex Ante Load Impact Estimates for 1-in-10 CAISO System Conditions

Program Type	Program	Monthly System Peak											
		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Emergency	BIP-15	105	117	131	123	137	147	149	149	149	149	145	121
	BIP-30	435	433	434	473	515	506	495	518	499	506	460	435
	AP-I	28	25	35	48	55	55	53	55	43	44	26	26
	SUB-TOTAL	**568**	**575**	**600**	**645**	**708**	**708**	**697**	**721**	**691**	**700**	**631**	**582**
Price-responsive	SDP-C	7	9	15	29	33	32	34	39	42	34	16	7
	SDP-R	0	0	16	126	170	192	221	247	253	170	31	0
	CPP-Large	14	14	15	33	31	30	28	30	30	33	16	14
	CPP-Medium	0	0	0	0	0	0	0	0	0	0	0	0
	CPP-Small	0	0	0	0	0	0	0	0	0	0	0	0
	DBP	49	49	54	53	62	102	101	103	99	62	59	47
	SUB-TOTAL	**70**	**73**	**100**	**241**	**296**	**355**	**385**	**419**	**423**	**299**	**122**	**69**
Demand Response Aggregator-managed	CBP-DA	1	1	1	1	1	1	2	2	2	2	1	1
	CBP-DO	24	25	25	26	23	28	28	29	33	32	24	24
	AMP	83	82	82	82	80	78	77	79	77	77	83	83
	SUB-TOTAL	**108**	**108**	**109**	**109**	**104**	**107**	**107**	**110**	**112**	**111**	**108**	**108**
SmartConnect®-enabled	SPD with Tech.	1	1	0	10	11	12	13	15	16	14	0	1
	SUB-TOTAL	**1**	**1**	**0**	**10**	**11**	**12**	**13**	**15**	**16**	**14**	**0**	**1**
Nonevent Based	RTP	1	1	1	9	0	2	2	17	23	9	1	1
	PLS	0*	0*	0*	0*	0*	0*	0*	0*	0*	0*	0*	0*
	SUB-TOTAL	**1**	**1**	**1**	**9**	**0**	**2**	**2**	**17**	**23**	**9**	**1**	**1**
PORTFOLIO TOTAL		**748**	**758**	**809**	**1,013**	**1,118**	**1,185**	**1,204**	**1,281**	**1,265**	**1,131**	**862**	**760**

*Load impacts are redacted to protect confidential customer information

Table J-2: 2018 Program-specific Aggregate Ex Ante Load Impact Estimates for 1-in-10 CAISO System Conditions

Program Type	Program	Monthly System Peak											
		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Emergency	BIP-15	121	134	139	129	139	147	149	147	148	148	144	120
	BIP-30	435	433	432	470	509	499	488	508	490	498	451	427
	AP-I	29	26	35	49	56	56	53	55	44	45	26	26
	SUB-TOTAL	**585**	**593**	**606**	**648**	**705**	**702**	**690**	**710**	**681**	**690**	**621**	**573**
Price-responsive	SDP-C	6	8	14	27	30	30	31	36	39	31	15	7
	SDP-R	0	0	15	119	161	182	210	235	240	161	29	0
	CPP-Large	14	14	15	33	31	30	28	30	30	33	16	14
	CPP-Medium	0	0	0	0	0	0	0	0	0	4	1	1
	CPP-Small	0	0	0	0	0	0	0	0	0	1	0	0
	DBP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**20**	**23**	**44**	**180**	**223**	**242**	**270**	**301**	**309**	**230**	**62**	**22**
Demand Response Aggregator-managed	CBP-DA	3	3	3	3	3	4	5	5	6	6	3	3
	CBP-DO	37	38	39	40	35	43	43	45	51	49	36	36
	AMP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**40**	**42**	**42**	**43**	**38**	**47**	**48**	**50**	**56**	**54**	**40**	**39**
SmartConnect®-enabled	SPD with Tech.	1	1	0	15	16	17	19	20	22	19	0	2
	SUB-TOTAL	**1**	**1**	**0**	**15**	**16**	**17**	**19**	**20**	**22**	**19**	**0**	**2**
Nonevent Based	RTP	1	1	1	9	0	2	2	17	23	9	1	1
	PLS	0	0	0	0	4	4	4	4	5	4	0	0
	SUB-TOTAL	**1**	**1**	**1**	**9**	**4**	**6**	**7**	**21**	**27**	**13**	**1**	**1**
PORTFOLIO TOTAL		**647**	**659**	**692**	**894**	**986**	**1,014**	**1,033**	**1,103**	**1,095**	**1,006**	**723**	**637**

Table J-3: 2019 Program-specific Aggregate Ex Ante Load Impact Estimates for 1-in-10 CAISO System Conditions

Program Type	Program	Monthly System Peak											
		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Emergency	BIP-15	121	133	138	128	138	147	149	146	147	147	142	120
	BIP-30	426	424	424	460	497	487	476	496	478	485	440	416
	AP-I	29	26	35	49	57	56	53	55	44	45	26	26
	SUB-TOTAL	**576**	**583**	**597**	**637**	**691**	**690**	**678**	**697**	**668**	**676**	**609**	**562**
Price-responsive	SDP-C	6	8	13	25	28	28	29	34	36	29	14	6
	SDP-R	0	0	14	114	153	173	200	223	228	153	28	0
	CPP-Large	14	14	15	33	32	30	29	30	30	33	16	14
	CPP-Medium	1	1	1	4	4	4	4	4	4	10	4	3
	CPP-Small	0	0	0	1	1	1	1	1	1	6	4	4
	DBP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**21**	**24**	**44**	**176**	**218**	**235**	**262**	**292**	**299**	**231**	**66**	**28**
Demand Response Aggregator-managed	CBP-DA	3	3	3	3	3	4	5	5	6	6	3	3
	CBP-DO	37	38	39	40	35	43	43	45	51	49	36	36
	AMP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**40**	**42**	**42**	**43**	**38**	**47**	**48**	**50**	**56**	**54**	**40**	**39**
SmartConnect®-enabled	SPD with Tech.	2	2	0	19	21	21	24	25	27	23	0	2
	SUB-TOTAL	**2**	**2**	**0**	**19**	**21**	**21**	**24**	**25**	**27**	**23**	**0**	**2**
Nonevent Based	RTP	1	1	1	9	0	2	2	17	23	9	1	1
	PLS	0	0	0	0	5	5	6	6	6	5	0	0
	SUB-TOTAL	**1**	**1**	**1**	**9**	**5**	**8**	**8**	**22**	**28**	**14**	**1**	**1**
PORTFOLIO TOTAL		**639**	**650**	**684**	**884**	**973**	**1,001**	**1,020**	**1,087**	**1,080**	**999**	**715**	**632**

Table J-4: 2020 Program-specific Aggregate Ex Ante Load Impact Estimates for 1-in-10 CAISO System Conditions

Program Type	Program	Monthly System Peak											
		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Emergency	BIP-15	120	132	137	127	137	146	148	145	145	146	137	115
	BIP-30	416	412	413	450	487	479	467	486	468	475	431	408
	AP-I	29	26	35	49	56	56	53	55	43	45	26	26
	SUB-TOTAL	**565**	**570**	**585**	**626**	**680**	**680**	**668**	**686**	**657**	**666**	**595**	**549**
Price-responsive	SDP-C	5	7	12	23	26	25	27	31	33	27	13	6
	SDP-R	0	0	13	108	146	165	190	212	217	146	26	0
	CPP-Large	14	14	15	33	32	30	29	30	30	33	16	14
	CPP-Medium	3	3	4	9	9	10	10	11	11	4	2	1
	CPP-Small	5	4	4	6	6	7	7	8	8	3	2	2
	DBP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**27**	**29**	**48**	**179**	**219**	**237**	**263**	**292**	**299**	**212**	**58**	**23**
Demand Response Aggregator-managed	CBP-DA	3	3	3	3	3	4	5	5	6	6	3	3
	CBP-DO	37	38	39	40	35	43	43	45	51	49	36	36
	AMP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**40**	**42**	**42**	**43**	**38**	**47**	**48**	**50**	**56**	**54**	**40**	**39**
SmartConnect®-enabled	SPD with Tech.	2	2	0	23	25	26	28	31	33	28	0	2
	SUB-TOTAL	**2**	**2**	**0**	**23**	**25**	**26**	**28**	**31**	**33**	**28**	**0**	**2**
Nonevent Based	RTP	1	1	1	9	0	2	2	17	23	9	1	1
	PLS	0	0	0	0	5	6	6	6	6	6	0	0
	SUB-TOTAL	**1**	**1**	**1**	**9**	**6**	**8**	**8**	**23**	**29**	**14**	**1**	**1**
PORTFOLIO TOTAL		**635**	**643**	**676**	**880**	**968**	**998**	**1,016**	**1,081**	**1,074**	**974**	**693**	**614**

Table J-5: 2021 Program-specific Aggregate Ex Ante Load Impact Estimates for 1-in-10 CAISO System Conditions

Program Type	Program	Monthly System Peak											
		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Emergency	BIP-15	115	128	133	123	132	141	143	140	141	140	136	114
	BIP-30	407	405	406	440	479	469	458	477	460	466	423	401
	AP-I	29	25	35	49	55	55	52	54	43	44	25	25
	SUB-TOTAL	**551**	**559**	**573**	**612**	**666**	**665**	**653**	**671**	**643**	**649**	**584**	**540**
Price-responsive	SDP-C	5	6	11	21	24	23	25	29	30	25	12	5
	SDP-R	0	0	13	103	139	156	181	202	206	138	25	0
	CPP-Large	14	14	15	33	32	30	29	30	31	33	16	14
	CPP-Medium	1	1	1	4	4	4	4	4	4	4	2	1
	CPP-Small	2	2	2	2	3	3	3	3	3	3	2	2
	DBP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**22**	**24**	**42**	**163**	**201**	**217**	**241**	**268**	**275**	**203**	**56**	**22**
Demand Response Aggregator-managed	CBP-DA	3	3	3	3	3	4	5	5	6	6	3	3
	CBP-DO	37	38	39	40	35	43	43	45	51	49	36	36
	AMP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**40**	**42**	**42**	**43**	**38**	**47**	**48**	**50**	**56**	**54**	**40**	**39**
SmartConnect®-enabled	SPD with Tech.	2	2	0	27	30	30	33	36	38	32	1	3
	SUB-TOTAL	**2**	**2**	**0**	**27**	**30**	**30**	**33**	**36**	**38**	**32**	**1**	**3**
Nonevent Based	RTP	1	1	1	9	0	2	2	17	23	9	1	1
	PLS	0	0	0	0	6	6	7	7	7	6	0	0
	SUB-TOTAL	**1**	**1**	**1**	**9**	**6**	**8**	**9**	**23**	**29**	**15**	**1**	**1**
PORTFOLIO TOTAL		**616**	**627**	**658**	**854**	**940**	**968**	**984**	**1,048**	**1,042**	**954**	**681**	**605**

Table J-6: 2022 Program-specific Aggregate Ex Ante Load Impact Estimates for 1-in-10 CAISO System Conditions

Program Type	Program	Monthly System Peak											
		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Emergency	BIP-15	114	127	131	121	130	140	141	140	140	140	136	114
	BIP-30	400	398	398	431	469	461	449	468	452	459	418	396
	AP-I	28	25	34	48	55	54	51	53	42	43	25	25
	SUB-TOTAL	**542**	**550**	**563**	**600**	**654**	**654**	**642**	**661**	**634**	**642**	**578**	**535**
Price-responsive	SDP-C	4	6	10	20	22	22	23	26	28	23	11	5
	SDP-R	0	0	12	98	132	149	172	192	196	132	24	0
	CPP-Large	14	14	15	33	32	30	29	30	31	33	16	14
	CPP-Medium	1	1	1	4	4	4	4	4	4	4	2	1
	CPP-Small	2	2	2	2	3	3	3	3	3	3	2	2
	DBP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**22**	**23**	**41**	**156**	**192**	**207**	**230**	**256**	**262**	**194**	**54**	**22**
Demand Response Aggregator-managed	CBP-DA	3	3	3	3	3	4	5	5	6	6	3	3
	CBP-DO	37	38	39	40	35	43	43	45	51	49	36	36
	AMP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**40**	**42**	**42**	**43**	**38**	**47**	**48**	**50**	**56**	**54**	**40**	**39**
SmartConnect®-enabled	SPD with Tech.	3	3	0	31	34	35	38	41	44	37	1	3
	SUB-TOTAL	**3**	**3**	**0**	**31**	**34**	**35**	**38**	**41**	**44**	**37**	**1**	**3**
Nonevent Based	RTP	1	1	1	9	0	2	2	17	23	9	1	1
	PLS	0	0	0	0	6	6	7	7	7	7	0	0
	SUB-TOTAL	**1**	**1**	**1**	**9**	**6**	**9**	**9**	**24**	**30**	**15**	**1**	**1**
PORTFOLIO TOTAL		**607**	**618**	**646**	**840**	**924**	**952**	**967**	**1,031**	**1,026**	**943**	**673**	**600**

Table J-7: 2023 Program-specific Aggregate Ex Ante Load Impact Estimates for 1-in-10 CAISO System Conditions

Program Type	Program	Monthly System Peak											
		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Emergency	BIP-15	114	127	131	121	130	140	141	140	140	140	136	114
	BIP-30	396	394	395	429	467	459	449	468	452	459	418	396
	AP-I	28	25	34	48	54	54	51	53	42	43	25	25
	SUB-TOTAL	**538**	**545**	**560**	**598**	**652**	**652**	**642**	**661**	**634**	**642**	**578**	**535**
Price-responsive	SDP-C	4	5	9	18	20	20	21	24	26	21	10	4
	SDP-R	0	0	11	93	125	141	163	182	186	125	23	0
	CPP-Large	14	15	15	33	32	30	29	30	31	33	16	14
	CPP-Medium	1	1	1	4	4	4	4	4	4	4	2	1
	CPP-Small	2	2	2	2	3	3	3	3	3	3	2	2
	DBP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**21**	**23**	**39**	**150**	**184**	**198**	**220**	**244**	**250**	**186**	**52**	**22**
Demand Response Aggregator-managed	CBP-DA	3	3	3	3	3	4	5	5	6	6	3	3
	CBP-DO	37	38	39	40	35	43	43	45	51	49	36	36
	AMP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**40**	**42**	**42**	**43**	**38**	**47**	**48**	**50**	**56**	**54**	**40**	**39**
SmartConnect®-enabled	SPD with Tech.	3	3	0	35	38	40	43	46	49	41	1	3
	SUB-TOTAL	**3**	**3**	**0**	**35**	**38**	**40**	**43**	**46**	**49**	**41**	**1**	**3**
Nonevent Based	RTP	1	1	1	9	0	2	2	17	23	9	1	1
	PLS	0	0	0	0	6	7	7	8	8	7	0	0
	SUB-TOTAL	**1**	**1**	**1**	**9**	**7**	**9**	**10**	**24**	**30**	**15**	**1**	**1**
PORTFOLIO TOTAL		**603**	**614**	**641**	**836**	**919**	**946**	**962**	**1,025**	**1,020**	**939**	**671**	**600**

Table J-8: 2024 Program-specific Aggregate Ex Ante Load Impact Estimates for 1-in-10 CAISO System Conditions

Program Type	Program	Monthly System Peak											
		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Emergency	BIP-15	114	127	131	121	130	140	141	140	140	140	136	114
	BIP-30	396	394	395	429	467	459	449	468	452	459	418	396
	AP-I	28	25	34	48	54	54	51	53	42	43	25	25
	SUB-TOTAL	**538**	**545**	**560**	**598**	**652**	**652**	**642**	**661**	**634**	**642**	**578**	**535**
Price-responsive	SDP-C	4	5	8	17	18	18	19	22	24	19	9	4
	SDP-R	0	0	11	88	119	134	155	173	177	119	22	0
	CPP-Large	14	15	15	33	32	30	29	30	31	33	16	14
	CPP-Medium	1	1	1	4	4	4	4	4	4	4	2	1
	CPP-Small	2	2	2	2	3	3	3	3	3	3	2	2
	DBP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**21**	**23**	**38**	**144**	**176**	**189**	**210**	**233**	**238**	**178**	**50**	**21**
Demand Response Aggregator-managed	CBP-DA	3	3	3	3	3	4	5	5	6	6	3	3
	CBP-DO	37	38	39	40	35	43	43	45	51	49	36	36
	AMP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**40**	**42**	**42**	**43**	**38**	**47**	**48**	**50**	**56**	**54**	**40**	**39**
SmartConnect®-enabled	SPD with Tech.	3	3	0	40	43	44	48	51	55	46	1	4
	SUB-TOTAL	**3**	**3**	**0**	**40**	**43**	**44**	**48**	**51**	**55**	**46**	**1**	**4**
Nonevent Based	RTP	1	1	1	9	0	2	2	17	23	9	1	1
	PLS	0	0	0	0	7	7	7	8	8	7	0	0
	SUB-TOTAL	**1**	**1**	**1**	**9**	**7**	**9**	**10**	**24**	**30**	**16**	**1**	**1**
PORTFOLIO TOTAL		**603**	**614**	**640**	**834**	**915**	**942**	**957**	**1,019**	**1,014**	**936**	**669**	**600**

Table J-9: 2025 Program-specific Aggregate Ex Ante Load Impact Estimates for 1-in-10 CAISO System Conditions

Program Type	Program	Monthly System Peak											
		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Emergency	BIP-15	114	127	131	121	130	140	141	140	140	140	136	114
	BIP-30	396	394	395	429	467	459	449	468	452	459	418	396
	AP-I	28	25	34	48	54	54	51	53	42	43	25	25
	SUB-TOTAL	**538**	**545**	**560**	**598**	**652**	**652**	**642**	**661**	**634**	**642**	**578**	**535**
Price-responsive	SDP-C	3	5	8	15	17	17	17	20	22	17	8	4
	SDP-R	0	0	10	84	113	127	147	164	168	113	20	0
	CPP-Large	14	15	15	33	32	30	29	30	31	34	16	14
	CPP-Medium	1	1	1	4	4	4	4	4	4	4	2	1
	CPP-Small	2	2	2	2	3	3	3	3	3	3	2	2
	DBP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**21**	**22**	**37**	**138**	**168**	**181**	**201**	**222**	**228**	**170**	**48**	**21**
Demand Response Aggregator-managed	CBP-DA	3	3	3	3	3	4	5	5	6	6	3	3
	CBP-DO	37	38	39	40	35	43	43	45	51	49	36	36
	AMP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**40**	**42**	**42**	**43**	**38**	**47**	**48**	**50**	**56**	**54**	**40**	**39**
SmartConnect®-enabled	SPD with Tech.	4	4	0	44	47	49	53	57	60	51	1	4
	SUB-TOTAL	**4**	**4**	**0**	**44**	**47**	**49**	**53**	**57**	**60**	**51**	**1**	**4**
Nonevent Based	RTP	1	1	1	9	0	2	2	17	23	9	1	1
	PLS	0	0	0	0	6	7	7	7	8	7	0	0
	SUB-TOTAL	**1**	**1**	**1**	**9**	**7**	**9**	**10**	**24**	**30**	**15**	**1**	**1**
PORTFOLIO TOTAL		**603**	**614**	**639**	**832**	**912**	**938**	**952**	**1,014**	**1,008**	**933**	**667**	**600**

Table J-10: 2026 Program-specific Aggregate Ex Ante Load Impact Estimates for 1-in-10 CAISO System Conditions

Program Type	Program	Monthly System Peak											
		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Emergency	BIP-15	114	127	131	121	130	140	141	140	140	140	136	114
	BIP-30	396	394	395	429	467	459	449	468	452	459	418	396
	AP-I	28	25	34	48	54	54	51	53	42	43	25	25
	SUB-TOTAL	**538**	**545**	**560**	**598**	**652**	**652**	**642**	**661**	**634**	**642**	**578**	**535**
Price-responsive	SDP-C	3	4	7	14	15	15	16	18	20	16	8	3
	SDP-R	0	0	10	79	107	121	139	156	159	107	19	0
	CPP-Large	14	15	16	33	32	30	29	30	31	34	16	14
	CPP-Medium	1	1	1	4	4	4	4	4	4	4	2	1
	CPP-Small	2	2	2	2	3	3	3	3	3	3	2	2
	DBP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**20**	**22**	**36**	**133**	**161**	**173**	**192**	**212**	**217**	**163**	**46**	**21**
Demand Response Aggregator-managed	CBP-DA	3	3	3	3	3	4	5	5	6	6	3	3
	CBP-DO	37	38	39	40	35	43	43	45	51	49	36	36
	AMP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**40**	**42**	**42**	**43**	**38**	**47**	**48**	**50**	**56**	**54**	**40**	**39**
SmartConnect®-enabled	SPD with Tech.	4	4	0	48	52	53	58	62	66	55	1	5
	SUB-TOTAL	**4**	**4**	**0**	**48**	**52**	**53**	**58**	**62**	**66**	**55**	**1**	**5**
Nonevent Based	RTP	1	1	1	9	0	2	2	17	23	9	1	1
	PLS	0	0	0	0	6	6	7	7	7	7	0	0
	SUB-TOTAL	**1**	**1**	**1**	**9**	**6**	**9**	**9**	**24**	**30**	**15**	**1**	**1**
PORTFOLIO TOTAL		**603**	**614**	**638**	**831**	**909**	**934**	**948**	**1,008**	**1,003**	**930**	**666**	**600**

Table J-11: 2027 Program-specific Aggregate Ex Ante Load Impact Estimates for 1-in-10 CAISO System Conditions

Program Type	Program	Monthly System Peak											
		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
Emergency	BIP-15	114	127	131	121	130	140	141	140	140	140	136	114
	BIP-30	396	394	395	429	467	459	449	468	452	459	418	396
	AP-I	28	25	34	48	54	54	51	53	42	43	25	25
	SUB-TOTAL	**538**	**545**	**560**	**598**	**652**	**652**	**642**	**661**	**634**	**642**	**578**	**535**
Price-responsive	SDP-C	3	4	6	13	14	14	14	17	18	14	7	3
	SDP-R	0	0	9	75	102	115	132	148	151	101	18	0
	CPP-Large	14	15	16	34	32	31	29	30	31	34	16	14
	CPP-Medium	1	1	1	4	4	4	4	4	4	4	2	1
	CPP-Small	2	2	2	2	3	3	3	3	3	3	2	2
	DBP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**20**	**21**	**34**	**127**	**154**	**166**	**183**	**203**	**207**	**156**	**45**	**21**
Demand Response Aggregator-managed	CBP-DA	3	3	3	3	3	4	5	5	6	6	3	3
	CBP-DO	37	38	39	40	35	43	43	45	51	49	36	36
	AMP	0	0	0	0	0	0	0	0	0	0	0	0
	SUB-TOTAL	**40**	**42**	**42**	**43**	**38**	**47**	**48**	**50**	**56**	**54**	**40**	**39**
SmartConnect®-enabled	SPD with Tech.	5	5	0	52	56	58	63	67	71	60	1	5
	SUB-TOTAL	**5**	**5**	**0**	**52**	**56**	**58**	**63**	**67**	**71**	**60**	**1**	**5**
Nonevent Based	RTP	1	1	1	9	0	2	2	17	23	9	1	1
	PLS	0	0	0	0	6	6	7	7	7	6	0	0
	SUB-TOTAL	**1**	**1**	**1**	**9**	**6**	**9**	**9**	**24**	**30**	**15**	**1**	**1**
PORTFOLIO TOTAL		**603**	**614**	**637**	**829**	**906**	**931**	**944**	**1,004**	**999**	**927**	**664**	**600**

Appendix K SCE Demand Response Program Capacity for Reliability-based Resources

CPUC D.10-06-034 approved a settlement agreement, adopted by the California investor-owned utilities (IOU) and parties to Rulemaking 07-01-041, which places an upper limit on the combined load capacity of those programs that the IOUs may use to meet their respective resource adequacy requirements, beginning in 2012. Tables K-1 through K-11 present summaries of SCE's reliability-based program capacity, comparing that capacity to SCE's share of the overall limit, consistent section C.2 of the settlement agreement.

Table K-1: Portfolio-adjusted Load Impacts of Reliability Programs under 1-in-2 Weather Conditions – 2017

		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
1	BIP-15 Event Load Impacts Attributable to All Non-residential Customers Enrolled in BIP-15	109	121	129	120	136	147	148	149	149	150	142	123
2	BIP-30 Event Load Impacts Attributable to All Non-residential Customers Enrolled in BIP-30	432	437	433	469	502	490	489	511	486	500	453	433
3	AP-I Event Load Impacts Attributable to All Non-residential Customers Enrolled in AP-I	22	25	31	43	49	53	52	50	40	37	28	26
4	Load Impacts (BIP-15, BIP-30, and AP-I) Attributable Only to Customers Dually enrolled in Other Demand Response Programs	168	181	181	189	220	223	230	246	224	229	186	168
5	**Total Reliability Program Load Impacts MINUS Load Impacts Attributable to Customers Dually enrolled in Other Demand Response Programs (= (1) + (2) + (3) - (4))**	**395**	**402**	**411**	**442**	**467**	**468**	**459**	**464**	**451**	**458**	**437**	**413**
6	CAISO Control Area All-time Annual Coincident Peak Demand As of March 2017 (MW)[2]	50,270	50,270	50,270	50,270	50,270	50,270	50,270	50,270	50,270	50,270	50,270	50,270
7	Cap on Total Ex Ante Load Impacts of All Reliability DR Programs of PG&E, SCE, and SDG&E Combined as Percentage of CAISO Control Area All Time Annual Coincident Peak Demand	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
8	Tolerance Band	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
9	SCE Share of Cap on Reliability MW that Qualify for Resource Adequacy (=800 MW/(400 MW + 800 MW + 20 MW)	65.57%	65.57%	65.57%	65.57%	65.57%	65.57%	65.57%	65.57%	65.57%	65.57%	65.57%	65.57%
10	**Cap on SCE BIP Load Impacts That Qualify for Resource Adequacy (MW) (= (6) x (7) x (100% +(8)) x (9))**	**659**	**659**	**659**	**659**	**659**	**659**	**659**	**659**	**659**	**659**	**659**	**659**
11	**Amount by which Total Reliability Program Load Impacts MINUS Load Impacts Attributable to Customers Dually enrolled in Other Demand Response Programs Exceeds Cap (= (5) - (10))**	**-264**	**-257**	**-248**	**-217**	**-192**	**-191**	**-200**	**-195**	**-208**	**-201**	**-222**	**-246**

Table K-2: Portfolio-adjusted Load Impacts of Reliability Programs under 1-in-2 Weather Conditions – 2018

		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
1	BIP-15 Event Load Impacts Attributable to All Non-residential Customers Enrolled in BIP-15	126	139	136	126	138	147	148	148	148	149	141	122
2	BIP-30 Event Load Impacts Attributable to All Non-residential Customers Enrolled in BIP-30	433	436	430	465	496	484	482	501	477	491	445	425
3	AP-I Event Load Impacts Attributable to All Non-residential Customers Enrolled in AP-I	22	26	32	44	50	54	52	50	41	38	28	26
4	Load Impacts (BIP-15, BIP-30, and AP-I) Attributable Only to Customers Dually enrolled in Other Demand Response Programs	172	185	184	187	218	222	228	242	221	226	183	166
5	**Total Reliability Program Load Impacts MINUS Load Impacts Attributable to Customers Dually enrolled in Other Demand Response Programs (= (1) + (2) + (3) - (4))**	**408**	**415**	**414**	**447**	**466**	**464**	**455**	**457**	**444**	**452**	**430**	**407**
6	CAISO Control Area All-time Annual Coincident Peak Demand As of March 2017 (MW)[2]	50,270	50,270	50,270	50,270	50,270	50,270	50,270	50,270	50,270	50,270	50,270	50,270
7	Cap on Total Ex Ante Load Impacts of All Reliability DR Programs of PG&E, SCE, and SDG&E Combined as Percentage of CAISO Control Area All Time Annual Coincident Peak Demand	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
8	Tolerance Band	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
9	SCE Share of Cap on Reliability MW that Qualify for Resource Adequacy (=800 MW/(400 MW + 800 MW + 20 MW)	65.57%	65.57%	65.57%	65.57%	65.57%	65.57%	65.57%	65.57%	65.57%	65.57%	65.57%	65.57%
10	**Cap on SCE BIP Load Impacts That Qualify for Resource Adequacy (MW) (= (6) x (7) x (100% +(8)) x (9))**	**659**	**659**	**659**	**659**	**659**	**659**	**659**	**659**	**659**	**659**	**659**	**659**
11	**Amount by which Total Reliability Program Load Impacts MINUS Load Impacts Attributable to Customers Dually enrolled in Other Demand Response Programs Exceeds Cap (= (5) - (10))**	**-251**	**-244**	**-245**	**-212**	**-193**	**-195**	**-204**	**-202**	**-215**	**-207**	**-229**	**-252**

Table K-3: Portfolio-adjusted Load Impacts of Reliability Programs under 1-in-2 Weather Conditions – 2019

		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
1	BIP-15 Event Load Impacts Attributable to All Non-residential Customers Enrolled in BIP-15	125	138	135	125	137	147	148	146	147	147	139	121
2	BIP-30 Event Load Impacts Attributable to All Non-residential Customers Enrolled in BIP-30	424	427	422	455	484	472	469	489	465	478	434	414
3	AP-I Event Load Impacts Attributable to All Non-residential Customers Enrolled in AP-I	22	26	32	44	50	54	53	51	41	38	28	26
4	Load Impacts (BIP-15, BIP-30, and AP-I) Attributable Only to Customers Dually enrolled in Other Demand Response Programs	170	183	182	185	215	218	224	238	218	222	180	163
5	**Total Reliability Program Load Impacts MINUS Load Impacts Attributable to Customers Dually enrolled in Other Demand Response Programs (= (1) + (2) + (3) - (4))**	**401**	**408**	**408**	**439**	**456**	**455**	**446**	**448**	**435**	**442**	**421**	**398**
6	CAISO Control Area All-time Annual Coincident Peak Demand As of March 2017 (MW)[2]	50,270	50,270	50,270	50,270	50,270	50,270	50,270	50,270	50,270	50,270	50,270	50,270
7	Cap on Total Ex Ante Load Impacts of All Reliability DR Programs of PG&E, SCE, and SDG&E Combined as Percentage of CAISO Control Area All Time Annual Coincident Peak Demand	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
8	Tolerance Band	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
9	SCE Share of Cap on Reliability MW that Qualify for Resource Adequacy (=800 MW/(400 MW + 800 MW + 20 MW)	65.57%	65.57%	65.57%	65.57%	65.57%	65.57%	65.57%	65.57%	65.57%	65.57%	65.57%	65.57%
10	**Cap on SCE BIP Load Impacts That Qualify for Resource Adequacy (MW) (= (6) x (7) x (100% +(8)) x (9))**	**659**	**659**	**659**	**659**	**659**	**659**	**659**	**659**	**659**	**659**	**659**	**659**
11	**Amount by which Total Reliability Program Load Impacts MINUS Load Impacts Attributable to Customers Dually enrolled in Other Demand Response Programs Exceeds Cap (= (5) - (10))**	**-258**	**-251**	**-251**	**-220**	**-203**	**-204**	**-213**	**-211**	**-224**	**-217**	**-238**	**-261**

Table K-4: Portfolio-adjusted Load Impacts of Reliability Programs under 1-in-2 Weather Conditions – 2020

		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
1	BIP-15 Event Load Impacts Attributable to All Non-residential Customers Enrolled in BIP-15	124	137	134	124	136	146	147	145	146	146	135	116
2	BIP-30 Event Load Impacts Attributable to All Non-residential Customers Enrolled in BIP-30	414	415	412	445	474	464	461	479	456	469	425	406
3	AP-I Event Load Impacts Attributable to All Non-residential Customers Enrolled in AP-I	22	26	32	44	50	54	52	50	40	38	28	26
4	Load Impacts (BIP-15, BIP-30, and AP-I) Attributable Only to Customers Dually enrolled in Other Demand Response Programs	167	179	179	182	211	215	221	234	214	219	178	161
5	**Total Reliability Program Load Impacts MINUS Load Impacts Attributable to Customers Dually enrolled in Other Demand Response Programs (= (1) + (2) + (3) - (4))**	**393**	**400**	**399**	**431**	**449**	**449**	**440**	**441**	**428**	**434**	**410**	**388**
6	CAISO Control Area All-time Annual Coincident Peak Demand As of March 2017 (MW)[2]	50,270	50,270	50,270	50,270	50,270	50,270	50,270	50,270	50,270	50,270	50,270	50,270
7	Cap on Total Ex Ante Load Impacts of All Reliability DR Programs of PG&E, SCE, and SDG&E Combined as Percentage of CAISO Control Area All Time Annual Coincident Peak Demand	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
8	Tolerance Band	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
9	SCE Share of Cap on Reliability MW that Qualify for Resource Adequacy (=800 MW/(400 MW + 800 MW + 20 MW)	65.57%	65.57%	65.57%	65.57%	65.57%	65.57%	65.57%	65.57%	65.57%	65.57%	65.57%	65.57%
10	**Cap on SCE BIP Load Impacts That Qualify for Resource Adequacy (MW) (= (6) x (7) x (100% +(8)) x (9))**	**659**	**659**	**659**	**659**	**659**	**659**	**659**	**659**	**659**	**659**	**659**	**659**
11	**Amount by which Total Reliability Program Load Impacts MINUS Load Impacts Attributable to Customers Dually enrolled in Other Demand Response Programs Exceeds Cap (= (5) - (10))**	**-266**	**-259**	**-260**	**-228**	**-210**	**-210**	**-219**	**-218**	**-231**	**-225**	**-249**	**-271**

Table K-5: Portfolio-adjusted Load Impacts of Reliability Programs under 1-in-2 Weather Conditions – 2021

		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
1	BIP-15 Event Load Impacts Attributable to All Non-residential Customers Enrolled in BIP-15	119	133	130	120	131	142	142	140	141	141	133	115
2	BIP-30 Event Load Impacts Attributable to All Non-residential Customers Enrolled in BIP-30	405	408	404	436	466	455	452	470	447	460	417	399
3	AP-I Event Load Impacts Attributable to All Non-residential Customers Enrolled in AP-I	22	26	31	44	49	53	52	50	40	37	27	25
4	Load Impacts (BIP-15, BIP-30, and AP-I) Attributable Only to Customers Dually enrolled in Other Demand Response Programs	164	176	177	178	207	211	217	230	210	210	170	154
5	**Total Reliability Program Load Impacts MINUS Load Impacts Attributable to Customers Dually enrolled in Other Demand Response Programs (= (1) + (2) + (3) - (4))**	**383**	**390**	**390**	**421**	**439**	**439**	**429**	**431**	**418**	**427**	**407**	**385**
6	CAISO Control Area All-time Annual Coincident Peak Demand As of March 2017 (MW)[2]	50,270	50,270	50,270	50,270	50,270	50,270	50,270	50,270	50,270	50,270	50,270	50,270
7	Cap on Total Ex Ante Load Impacts of All Reliability DR Programs of PG&E, SCE, and SDG&E Combined as Percentage of CAISO Control Area All Time Annual Coincident Peak Demand	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
8	Tolerance Band	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
9	SCE Share of Cap on Reliability MW that Qualify for Resource Adequacy (=800 MW/(400 MW + 800 MW + 20 MW)	65.57%	65.57%	65.57%	65.57%	65.57%	65.57%	65.57%	65.57%	65.57%	65.57%	65.57%	65.57%
10	**Cap on SCE BIP Load Impacts That Qualify for Resource Adequacy (MW) (= (6) x (7) x (100% +(8)) x (9))**	**659**	**659**	**659**	**659**	**659**	**659**	**659**	**659**	**659**	**659**	**659**	**659**
11	**Amount by which Total Reliability Program Load Impacts MINUS Load Impacts Attributable to Customers Dually enrolled in Other Demand Response Programs Exceeds Cap (= (5) - (10))**	**-276**	**-269**	**-269**	**-238**	**-220**	**-220**	**-230**	**-228**	**-241**	**-232**	**-252**	**-274**

Table K-6: Portfolio-adjusted Load Impacts of Reliability Programs under 1-in-2 Weather Conditions – 2022

		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
1	BIP-15 Event Load Impacts Attributable to All Non-residential Customers Enrolled in BIP-15	118	131	129	118	129	140	141	140	140	141	133	115
2	BIP-30 Event Load Impacts Attributable to All Non-residential Customers Enrolled in BIP-30	397	401	397	427	457	447	443	462	440	453	411	394
3	AP-I Event Load Impacts Attributable to All Non-residential Customers Enrolled in AP-I	22	25	31	43	49	52	51	49	39	36	27	25
4	Load Impacts (BIP-15, BIP-30, and AP-I) Attributable Only to Customers Dually enrolled in Other Demand Response Programs	158	170	171	173	201	204	210	223	205	209	169	154
5	**Total Reliability Program Load Impacts MINUS Load Impacts Attributable to Customers Dually enrolled in Other Demand Response Programs (= (1) + (2) + (3) - (4))**	**379**	**387**	**386**	**415**	**434**	**435**	**424**	**428**	**415**	**421**	**402**	**380**
6	CAISO Control Area All-time Annual Coincident Peak Demand As of March 2017 (MW)[2]	50,270	50,270	50,270	50,270	50,270	50,270	50,270	50,270	50,270	50,270	50,270	50,270
7	Cap on Total Ex Ante Load Impacts of All Reliability DR Programs of PG&E, SCE, and SDG&E Combined as Percentage of CAISO Control Area All Time Annual Coincident Peak Demand	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
8	Tolerance Band	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
9	SCE Share of Cap on Reliability MW that Qualify for Resource Adequacy (=800 MW/(400 MW + 800 MW + 20 MW)	65.57%	65.57%	65.57%	65.57%	65.57%	65.57%	65.57%	65.57%	65.57%	65.57%	65.57%	65.57%
10	**Cap on SCE BIP Load Impacts That Qualify for Resource Adequacy (MW) (= (6) x (7) x (100% +(8)) x (9))**	**659**	**659**	**659**	**659**	**659**	**659**	**659**	**659**	**659**	**659**	**659**	**659**
11	**Amount by which Total Reliability Program Load Impacts MINUS Load Impacts Attributable to Customers Dually enrolled in Other Demand Response Programs Exceeds Cap (= (5) - (10))**	**-280**	**-272**	**-273**	**-244**	**-225**	**-224**	**-235**	**-231**	**-244**	**-238**	**-257**	**-279**

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Table K-7: Portfolio-adjusted Load Impacts of Reliability Programs under 1-in-2 Weather Conditions – 2023

		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
1	BIP-15 Event Load Impacts Attributable to All Non-residential Customers Enrolled in BIP-15	118	131	129	118	129	140	141	140	140	141	133	115
2	BIP-30 Event Load Impacts Attributable to All Non-residential Customers Enrolled in BIP-30	394	397	393	425	455	445	443	462	440	453	411	394
3	AP-I Event Load Impacts Attributable to All Non-residential Customers Enrolled in AP-I	22	25	31	43	48	52	51	49	39	36	27	25
4	Load Impacts (BIP-15, BIP-30, and AP-I) Attributable Only to Customers Dually enrolled in Other Demand Response Programs	157	169	169	173	201	204	210	223	205	209	169	154
5	**Total Reliability Program Load Impacts MINUS Load Impacts Attributable to Customers Dually enrolled in Other Demand Response Programs (= (1) + (2) + (3) - (4))**	**376**	**384**	**383**	**413**	**432**	**433**	**424**	**428**	**415**	**421**	**402**	**380**
6	CAISO Control Area All-time Annual Coincident Peak Demand As of March 2017 (MW)[2]	50,270	50,270	50,270	50,270	50,270	50,270	50,270	50,270	50,270	50,270	50,270	50,270
7	Cap on Total Ex Ante Load Impacts of All Reliability DR Programs of PG&E, SCE, and SDG&E Combined as Percentage of CAISO Control Area All Time Annual Coincident Peak Demand	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
8	Tolerance Band	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
9	SCE Share of Cap on Reliability MW that Qualify for Resource Adequacy (=800 MW/(400 MW + 800 MW + 20 MW)	65.57%	65.57%	65.57%	65.57%	65.57%	65.57%	65.57%	65.57%	65.57%	65.57%	65.57%	65.57%
10	**Cap on SCE BIP Load Impacts That Qualify for Resource Adequacy (MW) (= (6) x (7) x (100% +(8)) x (9))**	**659**	**659**	**659**	**659**	**659**	**659**	**659**	**659**	**659**	**659**	**659**	**659**
11	**Amount by which Total Reliability Program Load Impacts MINUS Load Impacts Attributable to Customers Dually enrolled in Other Demand Response Programs Exceeds Cap (= (5) - (10))**	**-283**	**-275**	**-276**	**-246**	**-227**	**-226**	**-235**	**-231**	**-244**	**-238**	**-257**	**-279**

Table K-8: Portfolio-adjusted Load Impacts of Reliability Programs under 1-in-2 Weather Conditions – 2024

		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
1	BIP-15 Event Load Impacts Attributable to All Non-residential Customers Enrolled in BIP-15	118	131	129	118	129	140	141	140	140	141	133	115
2	BIP-30 Event Load Impacts Attributable to All Non-residential Customers Enrolled in BIP-30	394	397	393	425	455	445	443	462	440	453	411	394
3	AP-I Event Load Impacts Attributable to All Non-residential Customers Enrolled in AP-I	22	25	31	43	48	52	51	49	39	36	27	25
4	Load Impacts (BIP-15, BIP-30, and AP-I) Attributable Only to Customers Dually enrolled in Other Demand Response Programs	157	169	169	173	201	204	210	223	205	209	169	154
5	**Total Reliability Program Load Impacts MINUS Load Impacts Attributable to Customers Dually enrolled in Other Demand Response Programs (= (1) + (2) + (3) - (4))**	**376**	**384**	**383**	**413**	**432**	**433**	**424**	**428**	**415**	**421**	**402**	**380**
6	CAISO Control Area All-time Annual Coincident Peak Demand As of March 2017 (MW)[2]	50,270	50,270	50,270	50,270	50,270	50,270	50,270	50,270	50,270	50,270	50,270	50,270
7	Cap on Total Ex Ante Load Impacts of All Reliability DR Programs of PG&E, SCE, and SDG&E Combined as Percentage of CAISO Control Area All Time Annual Coincident Peak Demand	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
8	Tolerance Band	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
9	SCE Share of Cap on Reliability MW that Qualify for Resource Adequacy (=800 MW/(400 MW + 800 MW + 20 MW)	65.57%	65.57%	65.57%	65.57%	65.57%	65.57%	65.57%	65.57%	65.57%	65.57%	65.57%	65.57%
10	**Cap on SCE BIP Load Impacts That Qualify for Resource Adequacy (MW) (= (6) x (7) x (100% +(8)) x (9))**	**659**	**659**	**659**	**659**	**659**	**659**	**659**	**659**	**659**	**659**	**659**	**659**
11	**Amount by which Total Reliability Program Load Impacts MINUS Load Impacts Attributable to Customers Dually enrolled in Other Demand Response Programs Exceeds Cap (= (5) - (10))**	**-283**	**-275**	**-276**	**-246**	**-227**	**-226**	**-235**	**-231**	**-244**	**-238**	**-257**	**-279**

Table K-9: Portfolio-adjusted Load Impacts of Reliability Programs under 1-in-2 Weather Conditions – 2025

		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
1	BIP-15 Event Load Impacts Attributable to All Non-residential Customers Enrolled in BIP-15	118	131	129	118	129	140	141	140	140	141	133	115
2	BIP-30 Event Load Impacts Attributable to All Non-residential Customers Enrolled in BIP-30	394	397	393	425	455	445	443	462	440	453	411	394
3	AP-I Event Load Impacts Attributable to All Non-residential Customers Enrolled in AP-I	22	25	31	43	48	52	51	49	39	36	27	25
4	Load Impacts (BIP-15, BIP-30, and AP-I) Attributable Only to Customers Dually enrolled in Other Demand Response Programs	157	169	169	173	201	204	210	223	205	209	169	154
5	**Total Reliability Program Load Impacts MINUS Load Impacts Attributable to Customers Dually enrolled in Other Demand Response Programs (= (1) + (2) + (3) - (4))**	**376**	**384**	**383**	**413**	**432**	**433**	**424**	**428**	**415**	**421**	**402**	**380**
6	CAISO Control Area All-time Annual Coincident Peak Demand As of March 2017 (MW)[2]	50,270	50,270	50,270	50,270	50,270	50,270	50,270	50,270	50,270	50,270	50,270	50,270
7	Cap on Total Ex Ante Load Impacts of All Reliability DR Programs of PG&E, SCE, and SDG&E Combined as Percentage of CAISO Control Area All Time Annual Coincident Peak Demand	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
8	Tolerance Band	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
9	SCE Share of Cap on Reliability MW that Qualify for Resource Adequacy (=800 MW/(400 MW + 800 MW + 20 MW)	65.57%	65.57%	65.57%	65.57%	65.57%	65.57%	65.57%	65.57%	65.57%	65.57%	65.57%	65.57%
10	**Cap on SCE BIP Load Impacts That Qualify for Resource Adequacy (MW) (= (6) x (7) x (100% +(8)) x (9))**	**659**	**659**	**659**	**659**	**659**	**659**	**659**	**659**	**659**	**659**	**659**	**659**
11	**Amount by which Total Reliability Program Load Impacts MINUS Load Impacts Attributable to Customers Dually enrolled in Other Demand Response Programs Exceeds Cap (= (5) - (10))**	**-283**	**-275**	**-276**	**-246**	**-227**	**-226**	**-235**	**-231**	**-244**	**-238**	**-257**	**-279**

Table K-10: Portfolio-adjusted Load Impacts of Reliability Programs under 1-in-2 Weather Conditions – 2026

		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
1	BIP-15 Event Load Impacts Attributable to All Non-residential Customers Enrolled in BIP-15	118	131	129	118	129	140	141	140	140	141	133	115
2	BIP-30 Event Load Impacts Attributable to All Non-residential Customers Enrolled in BIP-30	394	397	393	425	455	445	443	462	440	453	411	394
3	AP-I Event Load Impacts Attributable to All Non-residential Customers Enrolled in AP-I	22	25	31	43	48	52	51	49	39	36	27	25
4	Load Impacts (BIP-15, BIP-30, and AP-I) Attributable Only to Customers Dually enrolled in Other Demand Response Programs	157	169	169	173	201	204	210	223	205	209	169	154
5	**Total Reliability Program Load Impacts MINUS Load Impacts Attributable to Customers Dually enrolled in Other Demand Response Programs (= (1) + (2) + (3) - (4))**	**376**	**384**	**383**	**413**	**432**	**433**	**424**	**428**	**415**	**421**	**402**	**380**
6	CAISO Control Area All-time Annual Coincident Peak Demand As of March 2017 (MW)[2]	50,270	50,270	50,270	50,270	50,270	50,270	50,270	50,270	50,270	50,270	50,270	50,270
7	Cap on Total Ex Ante Load Impacts of All Reliability DR Programs of PG&E, SCE, and SDG&E Combined as Percentage of CAISO Control Area All Time Annual Coincident Peak Demand	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
8	Tolerance Band	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
9	SCE Share of Cap on Reliability MW that Qualify for Resource Adequacy (=800 MW/(400 MW + 800 MW + 20 MW)	65.57%	65.57%	65.57%	65.57%	65.57%	65.57%	65.57%	65.57%	65.57%	65.57%	65.57%	65.57%
10	**Cap on SCE BIP Load Impacts That Qualify for Resource Adequacy (MW) (= (6) x (7) x (100% +(8)) x (9))**	**659**	**659**	**659**	**659**	**659**	**659**	**659**	**659**	**659**	**659**	**659**	**659**
11	**Amount by which Total Reliability Program Load Impacts MINUS Load Impacts Attributable to Customers Dually enrolled in Other Demand Response Programs Exceeds Cap (= (5) - (10))**	**-283**	**-275**	**-276**	**-246**	**-227**	**-226**	**-235**	**-231**	**-244**	**-238**	**-257**	**-279**

Table K-11: Portfolio-adjusted Load Impacts of Reliability Programs under 1-in-2 Weather Conditions – 2027

		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
1	BIP-15 Event Load Impacts Attributable to All Non-residential Customers Enrolled in BIP-15	118	131	129	118	129	140	141	140	140	141	133	115
2	BIP-30 Event Load Impacts Attributable to All Non-residential Customers Enrolled in BIP-30	394	397	393	425	455	445	443	462	440	453	411	394
3	AP-I Event Load Impacts Attributable to All Non-residential Customers Enrolled in AP-I	22	25	31	43	48	52	51	49	39	36	27	25
4	Load Impacts (BIP-15, BIP-30, and AP-I) Attributable Only to Customers Dually enrolled in Other Demand Response Programs	157	169	169	173	201	204	210	223	205	209	169	154
5	**Total Reliability Program Load Impacts MINUS Load Impacts Attributable to Customers Dually enrolled in Other Demand Response Programs (= (1) + (2) + (3) - (4))**	**376**	**384**	**383**	**413**	**432**	**433**	**424**	**428**	**415**	**421**	**402**	**380**
6	CAISO Control Area All-time Annual Coincident Peak Demand As of March 2017 (MW)[2]	50,270	50,270	50,270	50,270	50,270	50,270	50,270	50,270	50,270	50,270	50,270	50,270
7	Cap on Total Ex Ante Load Impacts of All Reliability DR Programs of PG&E, SCE, and SDG&E Combined as Percentage of CAISO Control Area All Time Annual Coincident Peak Demand	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
8	Tolerance Band	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
9	SCE Share of Cap on Reliability MW that Qualify for Resource Adequacy (=800 MW/(400 MW + 800 MW + 20 MW)	65.57%	65.57%	65.57%	65.57%	65.57%	65.57%	65.57%	65.57%	65.57%	65.57%	65.57%	65.57%
10	**Cap on SCE BIP Load Impacts That Qualify for Resource Adequacy (MW) (= (6) x (7) x (100% +(8)) x (9))**	**659**	**659**	**659**	**659**	**659**	**659**	**659**	**659**	**659**	**659**	**659**	**659**
11	**Amount by which Total Reliability Program Load Impacts MINUS Load Impacts Attributable to Customers Dually enrolled in Other Demand Response Programs Exceeds Cap (= (5) - (10))**	**-283**	**-275**	**-276**	**-246**	**-227**	**-226**	**-235**	**-231**	**-244**	**-238**	**-257**	**-279**

Appendix B

SCE Notice of Availability (NOA) Served April 3, 2017

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Order Instituting Rulemaking To Enhance The Role Of Demand Response In Meeting The State's Resource Planning Needs And Operational Requirements.	R.13-09-011 (Filed September 19, 2013)

NOTICE OF AVAILABILITY OF SOUTHERN CALIFORNIA EDISON COMPANY'S (U 338-E) POSTING OF FINAL LOAD IMPACT REPORTS

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Dated: **April 3, 2017**

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Order Instituting Rulemaking To Enhance The Role Of Demand Response In Meeting The State's Resource Planning Needs And Operational Requirements.	R.13-09-011 (Filed September 19, 2013)

NOTICE OF AVAILABILITY OF SOUTHERN CALIFORNIA EDISON COMPANY'S (U 338-E) POSTING OF FINAL LOAD IMPACT REPORTS

Southern California Edison Company (SCE) hereby provides this Notice of Availability (NOA) of its posting of Program Year 2016 Final Demand Response (DR) Load Impact Reports pursuant to Rule 1.9 of the Rules of Practice and Procedure of the California Public Utilities Commission (CPUC or Commission), and in compliance with Commission Decisions (D.)08-04-050 and D.10-04-006.

SCE will be filing an amended report for the Base Interruptible Program as the original forecast of enrollments did not include 50 service accounts (SAs) that have been or will be added to the program due to participation in BIP aggregation. SCE's BIP does not usually have such a large increase in service account enrollments, so this increase coupled with the fact that SCE estimates we have reached our reliability cap is why an amended report will be filed.

SCE will also be filing an amended report for Save Power Day and Summer Discount Plan. During the analysis of the load impacts the internal and vendor quality control processes discovered that interval data was missing for both participant and non-participant (used for baseline calculations) customers for both programs. This issue has affected approximately 6,000 customer accounts and/or whole dates depending on event. SCE's Information Technology team has been working to recover and verify the missing interval data. This task has recently been completed but was too late to be included in the final report. SCE and its vendor have, however, concluded that the missing data should not and has not had a meaningful impact on the reported ex post and ex ante impacts.

SCE hereby provides notice to the service list in proceeding R.13-09-011[1] and the members of the Demand Response Measurement Evaluation Committee (DRMEC) that the final DR Load Impact Reports for program year 2016, with appendices and/or supporting tables, are available on SCE's website.

The executive summary report of SCE's annual study of DR activities, entitled "Southern California Edison's 2016 Demand Response Portfolio Summary Report," including final summary tables, has been filed with the Commission, as well as posted on SCE's website. In addition, the public versions[2] of the reports and supporting tables for each of the following SCE-specific DR programs have been posted on SCE's website:

1. *PY 2016 Load Impact Evaluation of Southern California Edison's Residential Summer Discount Plan – Final Report;*

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[1] Pursuant to the March 13, 2014 Email Ruling of ALJ Hymes directing the utilities to file their annual load impact reports in R.13-09-011 as the successor proceeding to R.07-01-041.

[2] Some of the information contained in certain reports or supporting tables (for both the SCE-specific and Statewide reports) is confidential. For the public versions of such reports and tables, documents that are confidential in-part will be redacted, and documents that are wholly confidential will be replaced with a "placeholder" document. The confidential version of the complete reports will be provided to the Commission and Commission Staff, as well as the Energy Division, and will include a Confidentiality Declaration in compliance with D.16-08-024 that provides a general description of the information that is confidential, the location of the confidential information, and the basis for confidential treatment. See Appendix C to SCE's *Compliance Filing Pursuant to Load Impact Protocol Filing Requirements* for a copy of this Confidentiality Declaration.

2. *PY 2016 Load Impact Evaluation of Southern California Edison's Commercial Summer Discount Plan – Final Report;*

3. *PY 2016 Load Impact Evaluation of Southern California Edison's Agriculture and Pumping Interruptible Program – Final Report;*

4. *PY 2016 Load Impact Evaluation of Southern California Edison's Real-Time Pricing Program – Final Report; and*

5. *PY 2016 Load Impact Evaluation of Southern California Edison's Residential Save Power Day Program – Final Report.*

Additionally, SCE hereby provides notice that the final PY 2016 DR Load Impact Reports, with summary tables, for each of the following statewide DR programs have been posted on SCE's website:

1. *2016 Statewide Load Impact Evaluation of California Aggregator Demand Response Programs: Ex-Post and Ex-Ante Load Impacts – Final Report*;

2. *2016 Load Impact Evaluation of California's Statewide Base Interruptible Program– Final Report*;

3. *2016 California Statewide Non-residential Critical Peak Pricing Evaluation – Final Report*;

4. *2016 Load Impact Evaluation of the California Statewide Permanent Load Shifting Program – Final Report*; and

5. *2016 Load Impact Evaluation of California Statewide Demand Bidding Programs for Non-Residential Customers: Ex Post and Ex Ante Report – Final Report*.

Please use the following instructions to access the final reports listed above (both SCE-specific and Statewide reports) on SCE's website:

- Directly access the documents at http://www3.sce.com/law/cpucproceedings.nsf/vwSearchProceedings?SearchView&Query=R.13-09-011&SearchMax=1000&Key1=1&Key2=25

- then click the icon in the "Attachment" column that corresponds to the document you want to view.

  OR

- Go to ***www.sce.com/applications***;

- Under “CPUC Open Proceedings,” type **R.13-09-011** into the search box;
- Click “GO;”
- From the Search Results screen, double-click the zip-file icon in the “Attachment” column that corresponds to the “SCE Final Load Impact Reports for Program Year 2016;”
- The documents are presented in Portable Document (.pdf) and Microsoft Excel (.xlsx) formats, and can be viewed online, printed, or saved to your own device.
- If you experience technical difficulties accessing the documents via the instructions outlined above, please contact Lisa Tobias, Paralegal, at (626) 302-3812 or Lisa.Tobias@sce.com.

These reports, with appendices, are voluminous and, therefore, physical copies of them can be provided on CD-ROM upon request to SCE Case Administration, who can be reached at (626) 302-3003 or case.admin@sce.com.

Respectfully submitted,

FADIA RAFEEDIE KHOURY
ROBIN Z. MEIDHOF

/s/ Robin Z. Meidhof

By: Robin Z. Meidhof

Attorneys for
SOUTHERN CALIFORNIA EDISON COMPANY

2244 Walnut Grove Avenue
Post Office Box 800
Rosemead, California 91770
Telephone: (626) 302-6054
Facsimile: (626) 302-6693
E-mail: Robin.Meidhof@sce.com

April 3, 2017

Appendix C

Confidentiality Declaration

DECLARATION SUPPORTING
CONFIDENTIAL DESIGNATION
ON BEHALF OF
SOUTHERN CALIFORNIA EDISON COMPANY

1. I, Shahana Samiullah, am a/the Senior Manager of Southern California Edison Company ("SCE"), a California corporation. Marc Ulrich, Vice President of Customer Program & Services of SCE, delegated authority to me to sign this declaration. My business office is located at:

   Southern California Edison
   2244 Walnut Grove Avenue
   Rosemead, CA 91770

2. I am making this declaration in accordance with the instructions set forth in California Public Utilities Commission (CPUC or Commission) Decision (D.) 16-08-024, which governs the submission of certain types of confidential documents to the Commission.

3. SCE will produce the information identified in paragraph 4 of this Declaration to the CPUC or to departments within or contractors retained by the CPUC in response to a CPUC audit, data request, proceeding or other CPUC related requests.

4. Title and description of document(s):

   A. Southern California Edison's 2016 Portfolio Summary Report

   These documents contain the annual load impact evaluation analysis for SCE's portfolio of demand response programs for the 2016 program year. The report and accompanying tables include detailed analysis of hourly load for fewer than 15 customers.

   B. FINAL_Statewide 2016 PLS Evaluation Report - Private – SCE.doc
   FINAL_SCE 2016 PLS Ex Post Load Impact Tables – Private.xls
   FINAL_SCE 2016 PLS Ex Ante Load Impact Tables - Incremental – Private.xls
   FINAL_SCE 2016 PLS Ex Ante Load Impact Tables - Embedded – Private.xls

These documents contain the annual load impact evaluation analysis for the Permanent Load Shifting (PLS) program from the 2016 program year. The report and accompanying tables include detailed analysis of hourly load for fewer than 15 customers.

C. 2016 Statewide BIP Evaluation – FINAL PRIVATE CONFIDENTIAL.docx
2016 Statewide BIP Evaluation – FINAL PRIVATE CONFIDENTIAL.pdf
SCE 2016 BIP Ex Ante Load Impact Tables – PRIVATE CONFIDENTIAL.xlsx
SCE 2016 BIP Ex-Post Load Impact Tables – PRIVATE CONFIDENTIAL.xlsx

These documents contain the annual load impact evaluation analysis for the Base Interruptible Program (BIP) program from the 2016 program year. The report and accompanying tables include detailed analysis of hourly load for fewer than 15 customers.

D. Appendix C DBP SCE Ex Post Protocol Table Generator 2015 PRIVATE.xlsx
Appendix E SCE DBP Ex Ante Protocol Table Generator 2015 PRIVATE.xlsx
PY15 DBP Report SCE PRIVATE Final.docx

These documents contain the annual load impact evaluation analysis for the Demand Bidding Program (DBP) program from the 2016 program year. The report and accompanying tables include detailed analysis of hourly load for fewer than 15 customers.

E. Aggregator DR Programs_PY2016 Eval Report_SCE_Confidential_Final
Ex Ante Final_SCE_AMP (Confidential Version)
Ex Ante Final_SCE_CBP (Confidential Version)
Ex Post Final_SCE_CBP (Confidential Version)
Ex Post Final_SCE_AMP (Confidential Version)

These documents contain the annual load impact evaluation analysis for the Aggregator Managed Programs (AMP) program from the 2016 program year. The report and accompanying tables include detailed analysis of hourly load for fewer than 15 customers

F. SDP-C Ex Ante Tables (CAISO Peak Conditions) (CONFIDENTIAL).xlsx
SDP-C Ex Ante Tables (SCE Peak Conditions) (CONFIDENTIAL).xlsx
SDP-C Ex Post Tables (CONFIDENTIAL).xlsx
SDP-R Ex Post Tables (CONFIDENTIAL).xlsx

These documents contain the annual load impact evaluation analysis for the Summer Discount Plan (SDP) program from the 2016 program year. The report and accompanying tables include detailed analysis of hourly load for fewer than 15 customers.

G. 2016 Statewide CPP Evaluation - Final Report - Private (Confidential) for SCE.doc
SCE 2016 Non-Res CPP Ex-Post Impact Tables Combined - Private.xls
SCE 2016 Non-Res CPP Ex Ante Tables CAISO Weather - Private.xls
SCE 2016 Non-Res CPP Ex Ante Tables Utility Weather - Private.xls

These documents contain the annual load impact evaluation analysis for the Critical Peak Pricing (CPP) program from the 2016 program year. The report and accompanying table listed include detailed analysis of hourly load, which includes some customer segments containing fewer than 15 customers.

5. These documents contain confidential information that, based on my information and belief, have not been publicly disclosed. These documents have been marked as confidential, and the basis for confidential treatment and where the confidential information is located on the documents are identified on the following chart:

Check	Basis for Confidential Treatment	Where Confidential Information is located on the documents
X	Customer-specific data, which may include names, addresses, social security, (and other personally identifiable information) demand, demand reduction, loads, amounts of savings, and billing data. (Protected under Civ. Code §§1798 *et seq.*; Govt. Code §6254; Public Util. Code §8380; Decisions (D.) 14-05-016, 04-08-055, 06-12-029; and General Order (G.O.) 77-M)	There is confidential information throughout the files listed in item 4 above. The following items solely contain confidential data: FINAL_Statewide 2016 PLS Evaluation Report - Private – SCE.doc FINAL_SCE 2016 PLS Ex Post Load Impact Tables – Private.xls FINAL_SCE 2016 PLS Ex Ante Load Impact Tables - Incremental – Private.xls FINAL_SCE 2016 PLS Ex Ante Load Impact Tables - Embedded – Private.xls Appendix C DBP SCE Ex Post Protocol Table Generator 2015 PRIVATE.xlsx Appendix E SCE DBP Ex Ante Protocol Table Generator 2015 PRIVATE.xlsx PY15 DBP Report SCE PRIVATE Final.docx The following contain a combination of confidential and non-confidential data, with confidential information in each document clearly marked: Southern California Edison's 2016 Portfolio Summary Report 2016 Statewide BIP Evaluation – FINAL PRIVATE CONFIDENTIAL.docx 2016 Statewide BIP Evaluation – FINAL PRIVATE CONFIDENTIAL.pdf SCE 2016 BIP Ex Ante Load Impact Tables – PRIVATE CONFIDENTIAL.xlsx SCE 2016 BIP Ex-Post Load Impact Tables – PRIVATE CONFIDENTIAL.xlsx Aggregator DR Programs_PY2016 Eval Report_SCE_Confidential_Final Ex Ante Final_SCE_AMP (Confidential Version)

	Ex Ante Final_SCE_CBP (Confidential Version) Ex Post Final_SCE_CBP (Confidential Version) Ex Post Final_SCE_AMP (Confidential Version) SDP-C Ex Ante Tables (CAISO Peak Conditions) (CONFIDENTIAL).xlsx SDP-C Ex Ante Tables (SCE Peak Conditions) (CONFIDENTIAL).xlsx SDP-C Ex Post Tables (CONFIDENTIAL).xlsx SDP-R Ex Post Tables (CONFIDENTIAL).xlsx 2016 Statewide CPP Evaluation - Final Report - Private (Confidential) for SCE.doc SCE 2016 Non-Res CPP Ex-Post Impact Tables Combined - Private.xls SCE 2016 Non-Res CPP Ex Ante Tables CAISO Weather - Private.xls SCE 2016 Non-Res CPP Ex Ante Tables Utility Weather - Private.xls

6. The importance of maintaining the confidentiality of this information outweighs any public interest in disclosure of this information. This information should be exempt from the public disclosure requirements under the Public Records Act and should be withheld from disclosure.
7. I declare under penalty of perjury that the foregoing is true, correct, and complete to the best of my knowledge.
8. Executed on this 3rd day of April 2017 at Rosemead, California.

/s/ Shahana Samiullah
Shahana Samiullah
Senior Manager
Southern California Edison Company

Attachment 2

2017 CPUC Assumptions and Scenario Document for Use in Long Term Planning

JF2/ek4 1/18/2017

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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Develop an Electricity Integrated Resource Planning Framework and to Coordinate and Refine Long-Term Procurement Planning Requirements.	Rulemaking 16-02-007 (Filed February 11, 2016)

ADMINISTRATIVE LAW JUDGE'S RULING SEEKING COMMENT ON ASSUMPTIONS AND ONE SCENARIO FOR USE IN LONG TERM PLANNING IN 2017

Summary

This Ruling requests parties' comments on the attached Draft 2017 Assumptions and Scenario proposed by California Public Utilities Commission (Commission) staff for use in long-term planning that may occur in 2017, with emphasis on the California Independent System Operator's (CAISO's) 2017-18 Transmission Planning Process (TPP).

It is anticipated that the attachment will also be used to support additional work in this proceeding on assumptions for use in integrated resource planning (IRP), and will ultimately be replaced by a similar document to be used in the IRP process. Parties will have additional opportunities to comment on the assumptions for IRP in the future. Comments in response to this ruling should focus primarily on the appropriateness of the attachment for use in the CAISO 2017-2018 TPP process.

As a courtesy and because of the relevance of these Assumptions and Scenario to renewables planning, this ruling is being served on parties in both this proceeding and the Renewables Portfolio Standard (RPS) implementation

rulemaking (R.) 15-02-020. Comments are to be filed only in this proceeding (R.16-02-007).

Comments may be filed and served by no later than February 3, 2017, with replies due no later than February 10, 2017.

Discussion

Commission staff has coordinated with the California Energy Commission (CEC) and the CAISO staff to recommend the attached Draft 2017 Assumptions and Scenario. The final version of the attachment, after revisions in response to parties' comments, is proposed to be used primarily for the purpose of the CAISO's TPP. It is also proposed to be utilized for any long-term resource planning studies that may be needed to support planning in 2017 prior to the Commission adopting formal guidance for the IRP process.

In previous years, the Assumptions and Scenarios have been released as part of the CPUC's Long-Term Procurement Plan (LTPP) proceeding. This year's document, the Draft 2017 Assumptions and Scenario, memorializes common assumptions to be used for long-term electricity system planning in the state of California. Traditionally, these assumptions were released in the LTPP Assumptions and Scenarios document. The Draft 2017 Assumptions and Scenario is now being published within this proceeding, which incorporates LTPP and acts as the successor proceeding to R.13-12-010.

It is anticipated that future Assumptions and Scenarios for use in long-term planning will be generated by the IRP process within this proceeding and endorsed by the Commission for future use in planning. Commission staff issued an informal draft of a similar document proposed for use in the IRP process to the service list on December 27, 2016. There will be an opportunity for parties to offer formal comments on these assumptions for IRP purposes later in this proceeding.

Additionally, a Scenario Tool has been historically issued along with the LTPP Assumptions and Scenarios. There will be no Scenario Tool update provided with this 2017 draft. The August 2016 Scenario Tool will remain the reference long-term planning load and resource table for California's electricity system until a successor is produced within this proceeding. The August 2016 Scenario Tool is available at: http://cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=12332.

Unlike previous LTPP cycles, the Draft 2017 Assumptions and Scenario document does not propose multiple scenarios for study. This type of guidance will be provided by other processes within this proceeding, and possibly successor proceedings, as the IRP process develops. Included in the Draft 2017 Assumptions and Scenario is a single scenario, the Reliability Scenario. The Reliability Scenario is very similar to the Infrastructure Investment Scenario articulated in the previous version of the LTPP Assumptions and Scenarios (May 2016).[1]

Previous versions of the LTPP Assumptions & Scenarios document contained information intended for use in policy-driven analyses in the CAISO's TPP process. Policy-driven analysis historically focused on identifying any transmission infrastructure needed to support the state's RPS program. By mutual agreement between the Commission, CAISO, and CEC staff, no RPS-related policy-driven analyses to identify new infrastructure needs beyond

[1] The 2016 Assumptions and Scenarios document is available at the following link: http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M162/K005/162005377.PDF.

what is necessary for a 33 percent RPS scenario are being provided by the Commission for consideration in long-term planning and for use by the CAISO for its 2017-18 TPP.[2]

In addition, the RPS Calculator version 6.2, referenced in the attached Draft 2017 Assumptions & Scenario, is available at http://www.cpuc.ca.gov/RPS_Calculator.

The Draft 2017 Assumptions and Scenario document includes the following changes from the previous version:

- The addition of a common set of load type definitions to facilitate modeling discussions across agencies;
- No projection for the doubling of Additional Achievable Energy Efficiency (AAEE) due to Senate Bill 350 (De León, 2015), since the setting of that goal is currently underway at the CEC;
- Regardless of interconnection domain, all storage resources are to be modeled as dispatchable and providing Resource Adequacy capacity;
- The assumption that there will be no renewable retirements within the planning timeframe; and
- Updated assumptions for combined heat and power, dispatchable storage, demand response, and renewable resources.

Parties are invited to comment on any and all aspects of the attachment and are also requested to respond to the following specific question in their comments on this ruling:

[2] The rationale for the RPS assumptions is explained in more detail in Section 4.1 of the attachment to this ruling.

1. Are the updates to the demand-side and supply-side assumptions reasonable and accurate? Please specify any assumptions that should be revised and provide a detailed justification supporting the recommended revisions.

Any party with technical questions on the Attachment to this ruling may contact the Commission's Energy Division for assistance. Please direct any such inquiries to Nathan Barcic at nathan.barcic@cpuc.ca.gov or Citlalli Sandoval at citlalli.sandoval@cpuc.ca.gov.

After review of the comments and replies in response to this ruling, an assigned Commissioner's Ruling will be issued endorsing a final 2017 Assumptions and Scenario Document for immediate use by the CAISO in its TPP process.

IT IS RULED that:

1. This ruling shall be served on parties to Rulemaking 15-02-020.
2. Interested parties may file and serve comments in this proceeding on the attached Draft 2017 Assumptions and Scenario, to be used for purposes of long-term electricity planning in 2017, with emphasis on the California Independent System Operator's Transmission Planning Process. Comments must be filed and served by no later than February 3, 2017. Parties are requested to include a response to the one specific question included in the text of this Ruling.

3. Interested parties may file and serve reply comments by no later than February 10, 2017.

Dated January 18, 2017, at San Francisco, California.

/s/ JULIE A. FITCH
Julie A. Fitch
Administrative Law Judge

ATTACHMENT
Draft 2017 Assumptions and Scenario for Long-Term Planning

Draft 2017 Assumptions and Scenario for Long Term Planning

Table of Contents

Table Index

Draft 2017 Assumptions and Scenario for Long Term Planning

1 Introduction

The California Public Utilities Commission (CPUC or "Commission,") staff has prepared this Draft 2017 Assumptions and Scenario for Long-Term Planning (Draft 2017 A&S) document in collaboration with staff from the California Energy Commission (CEC) and California Independent System Operator (CAISO).

In previous years, the Assumptions and Scenarios have been released in the CPUC's Long-Term Procurement Plan (LTPP) proceeding as the LTPP A&S Document.[1] This year's document, the Draft 2017 A&S, memorializes common assumptions to be used for long-term electricity system planning in the state of California. The Draft 2017 A&S is being issued within the 2016 Order Instituting Rulemaking to Develop an Electricity Integrated Resource Planning Framework and to Coordinate and Refine Long-Term Procurement Planning Requirements (R. 16-02-007), which incorporates LTPP and acts as the successor proceeding to R.13-12-010. It is anticipated that future Assumptions and Scenarios for use in long-term planning will be generated by the Integrated Resource Planning (IRP) process within R.16-02-007.

Historically, a Scenario Tool was issued along with the LTPP A&S. The Scenario Tool acts as an annual load and resource table which follows the assumptions outlined by the LTPP A&S document to illustrate how the planning reserve margin is met up to 20 years into the future. There will be no Scenario Tool update provided with this 2017 A&S. The August 2016 Scenario Tool[2] will remain the reference long-term planning load and resource table for California's electricity system until a successor is produced within this proceeding.

Similar to previous LTPP cycles, this document provides demand-side and supply-side planning assumptions that should, where appropriate, inform the CAISO 2017-2018 Transmission Planning Process (TPP) studies and long-term planning for the state of California. While both the CAISO TPP and IRP processes are expected to respond to stakeholder input, the objective is to maintain consistency between planning processes to the greatest extent possible.

Demand-side assumptions are based on the CEC's draft 2016 Integrated Energy Policy Report California Energy Demand Updated Forecast 2017-2027 (CEDU 2016). Supply-side assumptions reflect an annual projection of the mix and attributes of the future resource fleet, including existing and new conventional and renewable resources, as well as future retirements. Unlike previous LTPP cycles, this document does not propose multiple scenarios for study. This type of guidance will be provided by other processes within R.16-02-007, and successor proceedings, as the IRP process develops. Included in the Draft 2017 A&S is a single scenario, the Reliability Scenario. The Reliability Scenario is very

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[1] http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M162/K005/162005377.PDF

[2] http://cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=12332

similar to the Infrastructure Investment Scenario articulated in the previous version of the LTPP A&S (May 2016).[3]

Previous versions of the LTPP Assumptions & Scenarios document contained information intended for use in policy-driven analyses in the CAISO's TPP process. Policy-driven analysis historically focused on identifying any transmission infrastructure needed to support the state's Renewable Portfolio Standard (RPS) program. By mutual agreement, no RPS-related policy-driven analyses to identify new infrastructure needs beyond what is necessary for a 33% RPS scenario are being provided by the CPUC for consideration in long-term planning and for use by the CAISO for its 2017-18 TPP, as explained in more detail in Section 4.1.

Comments:

Parties to R.16-02-007 will be given the opportunity to provide comments and reply comments on this Draft 2017 A&S.

1.1 Terminology

Acronym	Definition
1-in-10	1-in-10 year weather peak demand forecast
1-in-2	1-in-2 year weather peak demand forecast
AAEE	Additional Achievable Energy Efficiency
AB	Assembly Bill
ACR	Assigned Commissioner Ruling
BTM	Behind-the-meter
CAISO	California Independent System Operator
CEC	California Energy Commission
CED	California Energy Demand Forecast
CEDU 2016	Draft 2016 Integrated Energy Policy Report California Energy Demand Updated Forecast, 2017-2027
CHP	Combined Heat and Power
CPUC	California Public Utilities Commission or "Commission"
DCPP	Diablo Canyon Power Plant
DR	Demand Response
Draft 2017	Draft 2017 Assumptions and Scenario for Long-Term Planning

[3] http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M162/K005/162005377.PDF

A&S	
EE	Energy Efficiency
ELCC	Effective Load Carrying Capability
GHG	Greenhouse Gas
GWh	Gigawatt Hour
IEPR	Integrated Energy Policy Report
ILR	Inverter Loading Ratio
IOU	Investor Owned Utility
LCR	Local Capacity Requirement
LSE	Load Serving Entity
LTPP	Long Term Procurement Plan
MW	Megawatt
MWh	Megawatt Hour
NMV	Net Market Value
NQC	Net Qualifying Capacity
OIR	Order Instituting Rulemaking
OTC	Once-through cooling
PG&E	Pacific Gas & Electric
POU	Publicly Owned Utility
PV	Photovoltaics
RFO	Request for Offers
RNS	Renewable Net Short
RPS	Renewable Portfolio Standard
SB	Senate Bill
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric
SWRCB	State Water Resources Control Board
TEPPC	Transmission Expansion Planning Policy Committee
TOU	Time-of-Use
TPP	Transmission Planning Process
WECC	Western Electricity Coordinating Council

1.2 Definitions

- **Load Forecast**: refers to the electricity demand served by the electric grid, measured by both peak demand and energy consumption. Load forecasts are influenced by a number of factors, such as State economics, demographics, behind-the-meter (BTM) resources and retail rates.

- **Assumption**: a statement that is made regarding the future for a given load forecast, or demand side or supply side energy resource, that should be used for procurement and transmission modeling purposes. For example, a forecasted load condition is an "assumption."
- **Scenario**: a set of assumptions about future conditions that is used in power system modeling performed to support generation or transmission planning.
- **Sensitivity**: is a variation on a scenario where only one variable is modified in order to assess its impact on the overall scenario results. Changing the retirement date of Diablo Canyon Power Plant, while holding other assumptions constant, is an example of a sensitivity.
- **Managed Forecast**: refers to the California Energy Demand Update (CEDU) Forecast that has been adjusted to account for the impact of load modifying programs that are expected to come online but that are not embedded into the baseline load forecast. An example of a "managed forecast" is a forecasted load that has been adjusted to account for energy efficiency programs that are not yet funded but that are expected to be implemented over the course of the planning horizon – frequently referred to as Additional Achievable Energy Efficiency (AAEE).
- **Probabilistic Load Level**: refers to the specific weather patterns assumed in the study year. For example, a 1-in-10 load level indicates a High load event due to weather patterns expected to occur approximately once every 10 years. The probabilistic load level primarily impacts annual peak demand (and other demand characteristics, such as variability) but does not significantly impact annual energy consumption.

1.3 Load Type Definitions

The CPUC, CEC, and CAISO have agreed upon a common modeling lexicon to facilitate modeling discussions across agencies. Note that in the CPUC production cost modeling work CPUC staff models behavior at the system level, and does not differentiate between sales and system load (i.e. staff grosses sales to the system level, accounting for distribution level losses).

Draft 2017 Assumptions and Scenario for Long Term Planning

Load Types	Relation to Other Terms	Rationale	Measurement
Consumption	Sum of electrical energy used to operate end-use devices excluding charge/discharge of storage	Consumption is the term used in CEC forms to capture onsite energy usage.	With increased self generation, and when relying on net energy metering to apply cost responsibility to end-users, consumption becomes counterfactual.
Sales	Consumption less BTM onsite generation including storage charge/discharge	Sales is the energy term to indicate the net energy delivered through the meter to the end-use customer	Metered by the utility on a short interval basis if the utility has deployed interval metering systems for end-users; otherwise could be estimated using load research practices
System	Sales load plus T&D losses plus theft and unaccounted for	Standard electricity industry term. CEC defines "hourly system load" in its data collection regulations	Generally measured by power plant output and import flows, e.g. a top down measurement inferring loads rather than a bottom up summation of individual customer loads
Net Load	System load less system intermittent renewable generation	This is the same definition as being used by CAISO	Balancing Area Authority estimation of system load less measured output of wind and solar supply-side renewables

1.4 Background

The Long-Term Procurement Plan (LTPP) proceedings were established to ensure a safe, reliable, and cost-effective electricity supply in California.[4] The LTPP proceeding addresses the overall long-term need for new system and local reliability resources, including the need for resources that provide operational flexibility.

[4] Pursuant to Assembly Bill (AB) 57 (Stats. 2002, ch. 850, Sec 3, Effective September 24, 2002), added Pub. Util. Code § 454.5., enabling resources to resume procurement of resources. *See also* OIR 3/27/2012, Scoping Memo 1.

Draft 2017 Assumptions and Scenario for Long Term Planning

To facilitate that ability of the public, staff, and decision-makers to compare and interpret the results of studies performed in different planning processes, the underlying study assumptions should align and be consistent. In order to ensure this alignment, consistency is needed for California's long-term planning assumptions. This Draft 2017 A&S document acts as a set of agreed-upon long-term planning assumptions until a successor document is adopted in this proceeding at a later date. The CPUC updates the planning assumptions on an annual basis in coordination and collaboration with the CAISO and the CEC. This document contains those updates.

1.5 History of LTPP Planning Assumptions

Since the 2006 LTPP the CPUC has worked to make the long-term procurement planning process more streamlined and transparent. The main effort of the 2008 LTPP was the creation of the *Energy Division Straw Proposal on LTPP Planning Standards*.[5] The 2010 LTPP took strides towards implementing that proposal, with adjustments based on party comments. CPUC Energy Division staff held several workshops in the summer of 2010, and in December of that same year, the *2010 LTPP Standardized Planning Assumptions* were issued via a Joint Scoping Memo and Ruling.[6] Following a similar process of workshops and comments in 2012 and 2013, the CPUC established LTPP planning assumptions for the 2012 and 2014 LTPP that build upon previous planning efforts to further improve the LTPP process.

The Order Instituting Rulemaking for R.16-02-007 was issued on February 19, 2016. R.16-02-007 is the Commission's primary venue for implementing the requirements related to Integrated Resource Planning mandated by Senate Bill 350: the Clean Energy and Pollution Reduction Act (de León, Chapter 547, Statutes of 2015) (SB 350). This proceeding also incorporates LTPP activities from R.13-12-010. This Draft 2017 A&S document acts as a bridge between the previous LTPP process and the successor IRP process. It is intended to provide continued coordination with the CAISO TPP process, keeping in accordance with the Joint Agency Process Alignment Agreement[7].

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[5] *Energy Division Straw Proposal on LTPP Planning Standards*, http://docs.cpuc.ca.gov/published/Graphics/103215.PDF

[6] *See* Assigned Commissioner and Administrative Law Judge's Joint Scoping Memo and Ruling, issued December 3, 2012, http://docs.cpuc.ca.gov/EFILE/RULC/127542.htm

[7] Infrastructure planning in California is split among the California Public Utilities Commission (CPUC), California Energy Commission (CEC), and California Independent System Operator (CAISO). These agencies collaborate to ensure that planning activities use common assumptions and are periodically updated.

More information is available here: http://cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6630

Draft 2017 Assumptions and Scenario for Long Term Planning

2 Planning Scope: Area & Time Frame

The 2017 Assumptions and Scenario are created specifically with regards to the loads served by, and the supply resources interconnected to, the CAISO-controlled transmission grid and the associated distribution systems.[8] Similar to the historic LTPP planning period, the Draft 2017 A&S for long-term planning forecasts 20 years out in order to study the impacts of major infrastructure decisions under consideration. The long term nature of resource planning is necessary given that resources procurement decisions typically take three to nine years until fruition. While detailed planning assumptions are used to create an annual loads and resources assessment in the first 10-year period (2017-2027), more generic long-term assumptions are used in the second 10-year period (2027-2037), reflecting the greater uncertainties associated with forecasting a more distant future.[9] Nonetheless, shorter-term (present to 10 years out) implications for infrastructure policy decisions can be assessed in conjunction with the longer term (10 to 20 year out) implications that each decisions carries.

This document supersedes the previous versions of assumptions and scenarios in this proceeding.

3 Planning Assumptions

A description of assumptions is provided in this section.

3.1 Demand-side Assumptions

Through joint-agency coordination processes such as the Joint Agency Steering Committee (JASC) and the Demand Analysis Working Group (DAWG), the CPUC, CEC, and CAISO work together to ensure no double-counting of demand-side resources in the CEDU 2016.

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[8] The technical studies will model the entire Western Electricity Coordinating Council (WECC); this document describes the assumptions that should be used for the balancing areas located inside the CAISO service territory. For assumptions pertaining to the balancing authorities located outside of the CAISO service territory, modelers shall rely upon the latest TEPPC common case data:
https://www.wecc.biz/Reliability/WECC_2026CC_V1.5%20Package.zip

[9] The updates incorporated in this document will also inform the 2017-18 TPP studies.

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3.1.1 Baseline, Incremental, and Managed Forecasts

The CEC-adopted CEDU 2016[10] is used as the "baseline" forecast. Demand-side assumptions are either embedded in the baseline forecast or consist of adjustments made to the baseline forecast. Incremental resource projections, such as Additional Achievable Energy Efficiency (AAEE),[11] are not embedded in the baseline forecast, but can be used to modify the baseline forecast to create a net or "managed" forecast. As an example, in the CEDU 2016 the CEC embeds an amount of energy efficiency representing current codes and standards and established energy efficiency programs. AAEE represents future expected energy and capacity savings from programs not yet established or funded; as such, AAEE is considered an incremental resource projection to the Energy Efficiency (EE) embedded in the CEDU 2016. In addition to its "baseline" demand forecast, the CEC publishes managed load forecasts which embed different levels of AAEE assumptions.

For modeling purposes the CEC provides its AAEE savings projections at the transmission bus-bar level to the CAISO; this information offers AAEE locational specificity to the CAISO and is provided on yearly basis for the given TPP's 10-year planning horizon.

3.1.2 Locational Certainty

As California chooses to meet its electricity needs with increasing proportions of demand-side management resources, such as energy efficiency and customer-sited solar photovoltaic (PV) self-generation, it becomes increasingly important to accurately forecast the locations of these demand-side impacts in order to capture the benefits that these resources provide to the system. Reliability studies in transmission-constrained local areas depend on these demand-side resources being capable of providing capacity value within the electrical areas in which they are forecasted to be located; ideally, their capacity value and location would be forecasted at specific transmission-level bus-bar or substation locations so that they can offset local capacity requirements in these subareas. Historically, demand-side resource projections lacked the locational certainty needed to contribute to local reliability. Fortunately, the current CED set of forecasts, with its embedded demand-side resources and incremental AAEE projections, is increasingly incorporating greater locational certainty by providing impacts at the climate zone level for BTM resources. The CEC defines 15 climate zones in California.[12] Efforts are underway to further refine the locational certainty of all BTM demand-side resources[13], to the transmission substation

[10] See the CED: California Energy Demand 2017-2027 Forecast, http://www.energy.ca.gov/2016_energypolicy/

[11] AAEE projections: https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=16-IEPR-05

[12] See p. 51 of http://www.energy.ca.gov/2013publications/CEC-200-2013-004/CEC-200-2013-004-V1-CMF.pdf

[13] Distribution Resources Plan Proceeding: R.14-08-013 and Integrated Distributed Energy Resources Proceeding: R.14-10-003

level, so that the capacity benefit provided by these resources can be appropriately counted on as a potential alternative to local conventional generation. [14]

3.1.3 Load

The CEC's CEDU 2016 set of forecasts, serves as the source for the "managed demand forecasts;" it consists of a base load forecast coupled with several alternative AAEE projections (see subsection on Energy Efficiency below). CEDU 2016 is an update of the full CED 2015 forecast, developed to incorporate more recent economic and demographic projections and the latest historical data. All other factors, such as projected load-modifying demand response, efficiency impacts, and rates are unchanged from CED 2015. The CEDU base forecasts include three load cases, "Low," "Mid," and "High," each factoring in variations on economic and demographic growth, retail electricity rates, fuel prices, and other elements. Each load case also has peak demand weather variants, for example, 1-in-2 weather year and 1-in-10 weather year.

While the CED forecasts use the best available information, they do not include all future expected activity. For example, the CEDU 2016 base forecast does not include the impact of the CPUC's recently adopted rate changes. Additionally, the CEDU 2016 does not incorporate changes expected to result from the adoption of Senate Bill 350.

The CEDU 2016 forecasts do account for the electrification of the transportation sector. However, development of policies that drive higher electrification growth is underway and may result in a different level of penetration of electric vehicles (EVs) across all vehicle types, including rail electrification, than what is embedded in the CEDU 2016 base load forecast.

The CEDU 2016 forecasts also included sensitivity analysis to account for the "peak shift" effect resulting from high penetrations of behind-the-meter rooftop photovoltaic solar systems, as discussed in further detail in subsequent sections. The CEC published the CEDU 2016 forecasts in December 2016.

For planning studies that utilize an 8760 hour load profile as input, the load profile should have annual peak and energy values consistent with the CEDU forecasts for the year being studied. The base load profile should be adjusted by using CEC-provided AAEE load shapes described in the following subsection. For planning studies that utilize a single historical

[14] For the past three TPP cycles, the CEC staff have developed load bus projections of AAEE peak savings to enable the CAISO to include these savings in its power flow studies. These "translations" of the approved AAEE projections, for use in the TPP, are not explicitly adopted by the CEC.

year as the basis for 8760 hour load shapes, the historical year should match the year used in the TEPPC 2026 Common Case.[15]

3.1.4 Energy Efficiency

Energy efficiency forecasts are developed from the CEDU 2016 base forecasts and its supplemental AAEE projections. Each load case of the CED base forecasts contains an embedded EE component that will be paired with an AAEE projection scenario representing additional savings. CEC staff, with input from the Demand Analysis Working Group and in consultation with CPUC staff and CAISO staff, developed the AAEE projections. In general, the lowest savings scenario includes only the EE savings most certain to materialize while the highest savings scenario includes all EE potential including aspirational goals (e.g. emerging technologies). Depending on the type of planning study, finer granularity of EE savings projections may be required.

Some planning study types may utilize EE savings projections allocated at the transmission-level bus-bar, and/or daily and seasonal load-shape EE savings projections. The CEC is developing 8760 load shapes for AAEE that match to the aggregate AAEE projections documented as part of the revised demand forecast. This task was undertaken so that modelers will not have to make up their own hourly shape, or debit it from peak and annual energy, and then effectively apply the same shape to AAEE as they do for the base forecast. We require that modelers use these 8760 hourly load reduction values when submitting studies to the CPUC, CEC or the CAISO. Transmission and distribution loss-avoidance effects shall be accounted in all studies.

The CEDU 2016 1-in-2 and 1-in-5 weather year, Mid-Baseline-Mid-AAEE forecasts should be used for the CAISO's system and bulk reliability studies in the 2017-18 TPP cycle.[16] The 1-in-10 weather year, Mid-Baseline-Low-AAEE forecast should be used for local reliability studies. The Mid-Baseline-Low AAEE scenario is appropriate for local reliability studies given the difficulty of forecasting load and AAEE at specific locations.

The May 2016 A&S document included a methodology to derive an AAEE forecast that corresponded to SB 350 AAEE goals. The Draft 2017 A&S does not attempt to approximate the additional AAEE envisioned by SB 350. SB 350 tasks the CEC with identifying AAEE savings and establishing targets for statewide energy efficiency savings and demand reductions to achieve doubling of energy efficiency by January 1, 2030. Agreement on how to implement SB 350's AAEE goals and how to model them will be arrived at in a separate

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[15] The TEPPC 2024 Common Case used the year 2005 as the basis for load shapes because it reflected an average weather year. TEPPC uses 2009 as the basis for load shapes in the 2026 Common Case.

[16] See the "Reliability Scenario" included in section 5.1 "2017 Planning Scenario – Reliability Scenario"

venue after they are established by the CEC, in coordination with the CPUC, and later will be reflected in the Integrated Resource Planning (IRP) process ordered by SB 350.

The CPUC staff will work with the CEC staff to develop, in a manner consistent with the CAISO-wide aggregate energy efficiency savings: (1) the specific hourly values appropriate to production simulation modeling, and (2) load bus modifiers that can be used in power flow modeling.

3.1.5 Solar Photovoltaics

Embedded Impacts

The Mid BTM PV assumption included in this document assumes no change to the BTM PV embedded in the Mid-demand IEPR forecast; the Mid-demand IEPR forecast incorporates a Mid-level assumption for installed PV capacity.

Although BTM PV is generally regarded as a demand-side resource, both the CED forecast-embedded BTM PV and any incremental amounts could be modeled as supply resources (e.g. as a non-dispatchable resource with a fixed annual energy profile) in resource planning models. Under this modeling convention, the corresponding demand forecast assumptions in the resource planning model would need to be adjusted upward to remove the impact of BTM PV resources, since BTM PV resources would be separately accounted for as a supply-side resource. The appropriate upward adjustment would require adding back the peak and energy reduction impact of the BTM PV resources, plus avoided losses, to the demand forecast. Production cost modeling, including production cost modeling employed by the CAISO in transmission planning proceedings, often uses this modeling convention (modeling BTM PV as supply resources). Power flow and dynamic stability models, such as used in the CAISO's TPP transmission planning studies employ "composite load models" that model the BTM PV as a discrete subset of the load model.

The BTM PV resource assumptions described above are forecasts of the installed AC output of these resources, and reflect estimates of capacity contribution during IOU peak periods and annual energy production. The capacity contributions of BTM PV resources during IOU peak periods in different load areas are calculated by multiplying installed AC capacity by the "peak impact factor." In order to calculate the BTM PV resources annual energy production one must multiply the BTM PV resource "capacity factor" by the MW of installed BTM PV resource capacity and multiply the result by 8760 hours. The table below summarizes the IOUs' peak impact factor and capacity factor that should be used in resource planning studies. These factors are derived from the embedded BTM ("self-generation") PV resource assumption for each of the three major IOUs.

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Table 1: Small Solar PV Operational Attributes

Variable	**PG&E**	**SCE**	**SDG&E**	**Average of all 3 IOUs**
Peak Impact factor	0.353	0.383	0.385	0.369
Capacity factor	0.184	0.186	0.172	0.185

The physical configuration of BTM PV resources influences the shape of hourly generation profiles and has material impact on the outcome of resource planning studies that inform the TPP and the LTPP. Two important physical attributes are the PV mounting type and the DC-AC inverter loading ratio. For BTM PV resources, the Mid assumption for mounting type is fixed-tilt, south-facing. The ratio of panel capacity to inverter capacity is the "DC-AC inverter loading ratio;" a higher loading ratio tends to flatten or clip the production profile of a PV unit. Industry practice for PV installations has been to install a panel capacity larger than the inverter capacity in order to compensate for de-rate factors such as DC-AC conversions and losses and to maximize economic value. For BTM PV resources, the Mid assumption for DC-AC inverter loading ratio is 1.2,[17] which is consistent with the assumption used in the Transmission Expansion Policy Planning Committee (TEPPC) Common Case.[18]

Granular information on the location and physical attributes of installed BTM PV resources can be derived from public databases such as those found on the "Go Solar California" web portal.[19] However, CPUC staff believes the benefit of incorporating such granular information in long-term planning assumptions is small because the overall uncertainty in BTM PV aggregate installed capacity in the long term is a much larger driver of modeling results. Therefore CPUC staff defers consideration of this granular information to a future long-term planning cycle.

As mentioned above, models such as hourly production simulation models need to model BTM PV as a supply resource with a fixed profile, rather than as a load reduction in order to account for the hourly shape of solar generation. The source of underlying irradiance profiles and method for creating 8760 hour generation profiles for BTM PV should be documented by the modeler. The 8760 hour generation profiles should also be consistent with the technical attributes described above: fixed-tilt, south-facing, and DC-AC inverter

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[17] For BTM PV technology assumptions, the RPS Calculator uses the default settings of the National Renewable Energy Lab's PV Watts tool, including DC to AC size ratio of 1.1, fixed-tilt, and azimuth south-facing.

[18] https://www.wecc.biz/TransmissionExpansionPlanning/Pages/Datasets.aspx

[19] https://www.californiasolarstatistics.ca.gov/

loading ratio 1.2. By building 8760 hour generation profiles according to the BTM PV installed AC capacity and the assumed technical attributes specified in this subsection, the resulting annual energy production implied by the profiles may deviate slightly from the annual energy production forecasted by using the capacity factors in

Table 1.

Peak Shift

The CEDU 2016 includes an analysis of the "peak shift" effect. Demand modifiers such as BTM PV, AAEE, time-of-use-pricing, and electric vehicles may affect load in such a way that hourly load profiles change. This change in load profile can lead to a shift in the hour during which LSEs serve their peak load. This peak shift effect can result in peak load shifting to later hours in the day than the historical hour that the peak had occurred which is included in the CEDU base forecast. The CEDU 2016 includes a scenario analysis of potential peak shift and the resulting impact on peak demand served by utilities. The results of this analysis are provided as an alternative scenario to the managed forecast of the CEDU 2016 for use in CAISO's TPP process for the review of previously-approved projects or procurement of resource adequacy resources to maintain local reliability, but not for identification of new needs that could result in new transmission projects.

The CEDU 2016 peak shift scenario analysis consisted of three main components:

- Hourly load profiles for PV generation
- Hourly load profiles for AAEE savings
- Projected weather normalized hourly end-use loads for each of 8760 hours for each year

The impacts of time-of-use and electric vehicles were not included in this analysis. Estimated load shapes for these modifiers are at a preliminary stage, and require more data and study.

The preliminary analysis of the "peak shift" effect included in the CEDU 2016 indicates a clear upward trend in LSEs' peak load, demonstrating a peak load increase relative to the 2015 IEPR CED managed forecast due to a smaller contribution of peak reduction by BTM PV resources at the later hour due to the "peak shift" effect. Annual adjustments were calculated to be incremental to 2016 load.

3.1.6 Combined Heat and Power

The CEC traditionally forecasts a "consumption" energy demand forecast and then subtracts onsite self-generation, such as behind-the-meter Combined Heat and Power (CHP) generation, in order to compute the net energy for load. As such, the default assumption for BTM CHP resources assumes no change from what the CED forecasts embed. The BTM CHP resource capacity that does not export to the grid will not be modeled as a supply resource; its impact will be implicitly modeled by virtue of being embedded in the CEC load forecast. Any CHP resource that serves both BTM load and exports to the grid (or in some cases which only exports to the grid) will have its export component (net of the capacity and energy used onsite) modeled as a supply resource, as described in Section 3.2.3.

3.1.7 Demand Response

The CED forecasts embed the impacts of load-modifying[20] demand response (DR) programs. These programs are generally non-event-based and/or tariff-based and include existing Time-of-Use (TOU) rates,[21] Permanent Load Shifting, and Real Time Pricing. Certain event-based, price-responsive programs are also embedded in the CED forecasts and include Critical Peak Pricing and Peak Time Rebate programs.[22]

There may also be additional DR impacts that need to be explored. For example, a future DR impact may come from defaulting residential customers to TOU rates.[23] Commission staff will collaborate with CEC's staff to facilitate the study of the default residential customer TOU rate impact in the next major CEC IEPR CED planning cycle.

3.1.8 Energy Storage

Energy storage units shall be modeled as supply-side resources; therefore this document describes the planning assumptions for distribution-connected and customer-connected storage, as well as transmission-connected storage, within the "Supply-side Assumptions" section.

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[20] See D.14-03-026 in the Demand Response Rulemaking, R.13-09-011, for further background on "load-modifying" and "supply-side" DR programs and the meaning of these terms with respect to DR resource attributes.

[21] The latest CED forecasts embed the impact of the TOU rates and periods existing in 2014, as they were forecast in the IOU's April 2015 load impact reports. These do include: (for residential customers) continuation of the TOU rates existing in 2014, with essentially no growth in participation – no default – and no late-shift in TOU periods; and (for non-res customers) mandatory TOU but no late-shift in TOU periods.

[22] DR programs whose impacts are *not* embedded in the CED forecasts include several event-based, price-responsive and reliability programs. Within the LTPP planning horizon, these programs shall achieve full integration into the CAISO wholesale market and therefore count as supply-side DR. Section 3.2.5 describes assumptions about DR treated as supply-side resources.

[23] The CED forecasts embed the impacts from existing TOU rates but do not include potential impacts from TOU rate changes being considered such as default TOU rates and shifting price periods/seasons.

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3.1.9 Transportation Electrification

The CEDU 2016 Mid-demand case includes a transportation electrification assessment reflecting the best available California specific EV penetration information. This forecast, which is based on current policy trends, also includes expected electrification in airport ground support equipment, port cargo handling equipment, shore power, truck stops, forklifts, and truck refrigeration units through 2027. The default transportation electrification assumption included in this document assumes no change to the transportation electrification assumption that is embedded in the Mid-demand IEPR forecast.

3.1.10 Avoided Transmission and Distribution Losses

Demand-side resource projections need to account for avoided transmission and distribution losses when calculating the balance of projected supply and demand. The table below specifies factors supplied by the CEC for accounting of avoided transmission and distribution losses. These factors are applied to the demand-side resource projections in order to determine the avoided supply-side generation replaced by the presence of demand-side resources.

Table 2: Factors to Account for Avoided Transmission and Distribution Losses

	PG&E	SCE	SDG&E
Peak, distribution losses only	1.067	1.051	1.071
Peak, transmission and distribution losses	1.097	1.076	1.096
Energy, transmission and distribution losses	1.096	1.068	1.0709

3.2 Supply-side Assumptions

All supply-side resource assumptions are solely for planning study purposes. Inclusion or exclusion of a specific project or resource in the planning cycle has no implications on existing or future contracts. To the extent a specific project or resource turns out to not be available, the planning study assumes an electrically equivalent resource will be available. All supply-side resources should be categorized as either a local resource (specific to a local area), a generic system resource, or a non-CAISO resource. At this time, no degradation of resource production is accounted for in these planning assumptions.

Resource Representation In Planning Models

A variety of planning studies can use the supply-side resource assumptions described by this document. Production simulation models should use the actual physical resource attributes of the supply-side (as well as demand-side) resource portfolios specified by this document. Power flow (load flow) and stability studies such as those used in the CAISO's TPP typically need to translate actual physical resource attributes into expected resource output levels under the specific conditions being modeled in such studies.

For variable energy resources such as wind or solar energy resources, hourly production simulation models should use 8760-hour generation profiles for modeling production. The source of the underlying wind and irradiance profiles, and the method for creating the 8760-hour generation profiles, should be documented by the modeler. The 8760-hour generation profiles should also be consistent with the resource technologies and locations specified in the renewable resource portfolios described in Section 3.2.6 and (for solar PV) the specific technical attributes described in Section 3.2.7.

In the power flow and stability studies typical of the CAISO's TPP, a required input is the expected output level of variable resources under the specific conditions being modeled, usually a specific time-of-day during a particular season. The CAISO has historically relied on one of two mechanisms for calculating the expected output level.

One mechanism used the 8760 hour generation profiles for variable resources, described above; this mechanism requires extracting resource output levels corresponding to the time period being studied (e.g. peak, off-peak, partial peak, and light load base cases). The other mechanism relied on the historical Net Qualifying Capacity (NQC) of a variable resource (calculated in the Resource Adequacy proceeding using an exceedance methodology) as the basis for the expected output level from variable resources that share similar technological and locational attributes during the specific conditions being studied.

This document provides no additional guidelines for modifying the current modeling practices associated with the output levels of variable resources. The CPUC is actively considering the use of Effective Load Carrying Capability (ELCC) methods, which assigns capacity value to wind and solar resources. The ELCC could be used for system-wide studies that assess the reliability contribution of a resource over the course of an entire year. The Resource Adequacy proceeding will determine how the use of ELCC methods will inform NQC calculations for the purpose of system and/or local Resource Adequacy compliance. For 2016-17 TPP modeling purposes, the current Resource Adequacy exceedance methodology should continue to be utilized to model output levels of variable resources in the power flow (load flow) and stability studies typical of the CAISO's TPP.

3.2.1 Existing Resources

Existing resources are itemized by the 2017 Resource Adequacy compliance year NQC list. This list includes all online resources with a CAISO Resource ID and that qualify for provision of Resource Adequacy, regardless of resource type. The CAISO and CPUC both publish these lists annually on their respective websites.

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3.2.2 Conventional Additions

The default values for conventional resource additions 50 MW or larger derive from the list of power plant siting cases maintained on the CEC website.[24] The default values for conventional resource additions smaller than 50 MW derive from other databases maintained by the CEC. The CEC updates these lists several times per year. A power plant project shall be counted if it (1) has a contract, (2) has been permitted, and/or (3) has begun construction. A power plant project that does not meet these criteria may be counted if the staff of the agency with permitting jurisdiction expects the project to come online within the planning horizon.

3.2.3 Combined Heat and Power

Combined Heat and Power resources identified in this section export electricity to the grid.[25] The default projection for exporting CHP assumes that all retiring CHP resources less than or equal to 20 MW that are on the 2016 NQC list would be replaced on a one-to-one basis by similar CHP resources; CHP resources that are greater than or equal to 20 MW will be assumed to retire based on a 40 year life cycle, or contract expiration date (whichever is furthest out).

Exporting CHP resources will be modeled as follows. First, one half of the exporting CHP capacity of each CHP resource will be assumed to operate on a historic profile as reflected by its monthly values on the 2016 NQC list and should be modeled as non-dispatchable resources. Secondly, the remaining half of the exporting capacity of each CHP resource will be assumed to be resources that are dispatchable by the CAISO.

3.2.4 Energy Storage

CPUC D. 13-10-040 established a 2020 procurement target[26] of 1,325 MW of newly installed energy storage capacity within the CAISO planning area. Of that amount, 700 MW needs to be transmission-connected, 425 MW needs to be distribution-connected, and 200 MW needs to be customer-side-connected. Unless otherwise noted via the IOUs' energy storage Applications, CPUC staff has assumed that 40% of the megawatts associated with transmission-connected and distribution-connected projects will provide two-hour storage, 40% of these projects' megawatts will provide four-hour storage, and the

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[24] http://www.energy.ca.gov/sitingcases/all_projects.html

[25] The NQC list includes values for only that portion of the exporting CHP facility that is used to export. For example, if a CHP facility has a 100 MW capacity and 40MW of that capacity is dedicated to meet onsite energy consumption, the NQC list only reports NQC values associated with 60 MW of that facility.

[26] The Decision specifies that resources must be online by 2024 so in the planning assumptions, target amounts are reached in 2024.

remaining 20% will provide six-hour storage. For energy storage projects connected on the "customer-side" – that is, behind-the-meter – CPUC staff assumes that 50% of these projects' megawatts will provide two-hour storage and 50% will provide four-hour storage.

Additionally, D.13-10-040 allocated a portion of the 1,325 MW energy storage procurement target to each of the three major IOUs.[27] Energy storage that is operational after January 1, 2010 and no later than December 31, 2024 shall count towards the procurement target. It is assumed that there will be no further growth in energy storage capacity targets, post 2024, beyond 1,325 MW.[28] Energy storage resources that are procured to satisfy a local capacity requirement also count towards satisfying the 1,325 MW energy storage target. Because such projects satisfy the local capacity RA requirement, they should be modeled as having at least a four-hour storage attribute, absent more specific information in the relevant procurement application.

Assumptions about storage attributes and capabilities

For modeling purposes, the entire 1,325 MW energy storage target shall be assumed to be operated such that the storage provides energy shifting, capacity, and flexibility services. The interconnection point of a storage resource does not determine its effectiveness for providing resource adequacy capacity, including flexible capacity, or ancillary services. In other words, regardless of interconnection domain (transmission-connected, distribution-connected, BTM), all storage shall be modeled as dispatchable and providing Resource Adequacy capacity and operational flexibility services. This represents a change in assumptions from the previous LTPP A&S.

[27] The CPUC also established an additional procurement target of 1% of load for ESPs and CCAs. The storage assumptions included herein do not include ESPs' or CCAs' storage resources.

[28] Decision 16-01-032 allows the IOUs to satisfy some of their transmission and distribution domain targets through customer-connected projects, up to a "ceiling" of 200% of the existing customer domain targets. A SCE data request response on this topic indicated that SCE has storage in response to LCR requirement that in effect over-procured a cumulative amount of 95MW of customer-side storage – see Table 6. SCE's customer-side storage target is 85 MW; meaning that 85 MW can be allocated to other energy storage domains. Even after the permissible shift of 85 MW, SCE exceeds its 85 MW customer-side target by 10 MW. As such, the expected statewide energy storage is 1,335 MW, although for simplicity's sake our "Residual Energy Storage Procurement To Meet D.13-10-040 Targets (MW)." Table 4, is based on the adopted 1,325 MW target.

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Table 3: Total Energy Storage Procurement To-Date (Based On IOU Data Received In Late 2016)

Domain	Transmission-connected	Distribution-connected	Customer-connected
SDG&E	40	44	20
SCE	55	204	199
PG&E	60	16	4
Total	155	264	268

Table 4: Residual Energy Storage Procurement To Meet D.13-10-040 Targets (MW)

Domain	Transmission-connected	Distribution-connected	Customer-connected
Total Capacity	545	160	0
Amount Providing RA Capacity	545	160	0
Amount Providing Flexibility	545	160	0
Amount with 2 hours of storage	218	64	0
Amount with 4 hours of storage	218	64	0
Amount with 6 hours of storage	109	32	0

In the CAISO's TPP Base local area reliability studies the transmission bus-bar identification numbers, names, etc., included in Table 5, Table 6 and Table 7, below, should be used for locational information regarding energy storage resources located in PG&E's,[29] SCE's and SDG&E's service territories.

[29] PG&E explained the following in regards to the energy storage resources listed in the "PG&E Energy Storage Resources" table: "The majority of the projects listed did not have completed interconnection studies nor were they included in the CAISO Full Network Model at the time of offer submittal. The list has also not been confirmed with the CAISO. Therefore the list is PG&E's current estimate of the nearest Transmission Point of Delivery / Receipt, nearest Resource ID, and nearest Bus ID, and should not be assumed to exactly denote the final bus-bar location."

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Summary: Energy Storage Assumptions Regarding RA, Flexibility and Depth/Duration used when project details are not known

Transmission-connected energy storage projects:

- All megawatts count for RA except:
    - If the energy storage project has a two-hour depth then it is de-rated by 50% in order to convert it MW into the amount of capacity actually counting towards RA (since by RA rules output must be sustained for minimum four-hours)
- All megawatts are assumed to provide operational flexibility to the grid
- For those projects whose duration/depth information was unavailable, we assume that 40% of their cumulative total megawatts provide two-hour storage, 40% provide four-hour storage, and 20% provide six-hour storage

Distribution-connected energy storage projects:

- All of the distribution-connected energy storage project's capacity counts towards RA and assumed to provide operational flexibility to the grid
- If the energy storage project only provides two-hour storage depth, it is derated by 50% in order to convert its capacity into an amount that can count towards meeting the RA obligation (since by RA rules output must be sustained for minimum four-hours)
- Energy Storage projects for which no duration/depth information was made available, we assume 40% of their cumulative total megawatts provide two-hour storage, 40% provide four-hour storage, and 20% provide six-hour storage

Customer-connected energy storage projects:

- All of a customer-connected energy storage project's capacity can count towards RA compliance, and is assumed to provide operational flexibility
- Energy storage projects for which no duration/depth information was made available, we assume 50% provide two-hour storage, 50% provide four-hour storage and 0% six-hour storage

It is reasonable to assume that cost-effectiveness requirements applicable to new storage capacity will lead to it being sited at the most optimal locations in order to allow these resources to help satisfy the local area reliability requirement. As CAISO staff identifies transmission constraints in the local areas in the current and future TPP technical studies they will also identify which transmission busses most optimally mitigate transmission constraints. Transmission, distribution and customer-side connected storage amounts providing capacity and flexibility identified in Table 4 should be distributed among the transmission busses which most optimally mitigate transmission constraints within local reliability areas. As such, the identified transmission bus locations are potential development sites for storage and should help inform the procurement of storage resources necessary to meet the storage procurement target.

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In regards to expedited storage procurement authorized through CPUC Resolution E-4791 (May 26, 2016), not all new storage facilities that are co-located at existing plants provide no net increases in the deliverable capacity available for meeting system or local capacity needs. Instead, IOUs have in some cases requested that a portion of the deliverable capacity associated with the existing plants be transferred to the new storage facilities to enable those facilities to achieve full capacity deliverability status, or have requested but not yet received deliverability. For those projects that have not received incremental deliverability through the ISO's 2017 Distributed Generation Deliverability process or an earlier process, those batteries will be treated as energy-only in normal scenarios.

In studying Aliso Canyon gas storage outage scenarios, the batteries will be studied with full capacity for the BESS and with 0 MW output from the associated gas plants due to assumed gas constraints. New storage facilities that are co-located at existing plants provide no net increase in the deliverable capacity available for meeting system or local capacity needs. Instead, IOUs have requested that a portion of the deliverable capacity associated with the existing plants be transferred to the new storage facilities to enable those facilities to achieve full capacity deliverability status.

Table 5: Locational Information for PG&E's Energy Storage Resources

PG&E Energy Storage Resources						
Counterparty (Project Name)	Point of Interconnection (POI)	Approximate Transmission Point of	Approximate Nearest Resource ID (ResID)	Approximate Bus ID (BusID)	MW	Point of Connection
Amber Kinetics (Energy Nuevo)	New 70 kV position in PG&E New Kearney Substation	New 70 kV position in PG&E New Kearney Substation	KERNEY_6_LD1	34480_KEARNEY _70.0_LD1	20	Transmission
Convergent (Henrietta)	Henrietta Distribution Substation (12kV)	Henrietta 70kV Substation	HENRTA_6_LD1	34540_HENRITTA_70.0_LD 1	10	Distribution
Hecate Energy (Molino)	Molino Transmission (69kV) Substation	Molino Transmission (69kV) Substation	MOLINO_6_LD1	31364_MOLINO _60.0_LD1	10	Transmission
NextEra Energy (Golden Hills)	Tesla Substation 115kV	Tesla Substation 115kV	TESLA_1_QF	33540_TESLA _115_GUM1	30	Transmission
Stem BTM	Customer Meter	Aggregated Sub Lap (TBD)	N/A	N/A	4	Customer
Yerba Buena Pilot Battery Project	21kV Swift 2102 Feeder (into Swift 21kV Substation)	Swift 115kV Substation	SWIFT_1_NAS (not yet operational)	35622_SWIFT _115_GUNS	4	Distribution
Vaca Dixon Pilot Battery Project	Vaca Dixon 12 kV Substation	Vaca Dixon 115kV Substation	VACADX_1_NAS	31998_VACA- DIX_115_GUNS	2	Distribution

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Table 6: Locational Information for SCE's Energy Storage Resources

SCE's Energy Storage Projects Locational Information by Busbar & Attributes (MW)

	Project	**Storage MW**	**Product Type**	**Locational Information**	**Bus ID**	
LCR RFO 264 MW	Ice Bear	28.64	ES BTM PLS (customer-side)	N/A (Distributed)		
	AES	100	IFOM (distribution)	**Point of Interconnection:** 230kV bus at the Alamitos A-Bank Substation **Bus Name:** ALMITOSW **Bus Number:** 24007		
	Stem	85	ES BTM (customer-sde)	N/A (Distributed)		
	Hybrid Electric	50	ES BTM (customer-sde)	N/A (Distributed)		
2016 ACES RFO/RFP	**Project**	**Storage MW**	**Product Type**	**Locational Information**		
	Powin	2	IFOM (distribution)	**Point of Interconnection:** 12kV Virgo Distribution line (Santiago A Bank Substation)	66 kV +H11:H35Bus Name: SANTIAGO 66 kV Bus Number: 24133	*No bus number for 12 kV Bus. 66 kV bus where B-station that feeds circuit is located used
	Western Grid [2]	5	IFOM (distribution)	**Point of Interconnection:** Wakefield Petit 16 kV Distribution line (Santa Clara A Bank Substation)	66 kV Bus Name: S.CLARA 66 kV Bus Number: 24127	
	AltaGas	20	IFOM (distribution)	**Point of Interconnection:** Ganesha Simpson 66kV line Distribution line (Chino A Bank Substation)	66 kV Bus Name: CHINO 66 kV Bus Number: 24024	*No bus number for 66 kV Transmission Line Tap. Chino 66 kV bus utilzied
	Project	**Storage MW**	**Product Type**	**Locational Information**		
2016 ACES DBT	Tesla	20	IFOM (distribution)	**Point of Interconnection:** Mira Loma A Bank Substation	66 kV Bus Name: MIRALOMW 66 kV Bus Number: 24210	
PRP 2	**Project**	**Storage MW**	**Product Type**	**Locational Information**		
	AMS CTEC 1-5	40	ES BTM (customer-sde)	N/A (Distributed)		
	Convergent OCES 1-3	35	IFOM (Transmission)	**Point of Interconnectio:** Chestnut 66kV bus out of Johanna 220/66kV substation	66 kV Bus Name: JOHANNA 66 kV Bus Number: 24207	
	Nextera OCES 1	8.5	ES BTM (customer-sde)	N/A (Distributed)		
	Nextera OCES 2	1.5	ES BTM (customer-sde)	N/A (Distributed)		
	SEF1	5	ES BTM (customer-sde)	N/A (Distributed)		
	Valencia Energy Storage	10	IFOM (distribution)	**Point of Interconnection:** Aquarius 12 kV circuit Santiago 220/66kV substation	66 kV Bus Name: SANTIAGO 66 kV Bus Number: 24133	*No bus number for 12 kV Bus. 66 kV bus where B-station that feeds circuit is located used
	HEJF1-2	15	IFOM (distribution)	**Point of Interconnection:** 12 kV bus at the Johanna substation	66 kV Bus Name: JOHANNA 66 kV Bus Number: 24207	*No bus number for 12 kV Bus. 66 kV bus where B-station that feeds circuit is located used
	NRG Hybrid 1-5 [1]	10	ES BTM (customer-sde)	N/A (Distributed)		
Bilateral	**Project**	**Storage MW**	**Product Type**	**Locational Information**		
	SCE EGT - Grapeland	10	IFOM (Transmission)	**Point of Interconnection:** Integrated with SCE's Grapeland Peaker	66 kV Bus Name: ETIWANDA 66 kV Bus Number: 24055 13.8 kV Bus Name: ETWPKGEN 13.8 kV Bus Number 29305 Project will share same 13.8 kV Bus where exsting peaker is located.	
	SCE EGT - Center	10	IFOM (Transmission)	**Point of Interconnection:** Integrated with SCE's Center Peaker	66 kV Bus Name: CENTER 66 kV Bus Number: 24203 13.8 kV Bus Name: CTRPKGEN 13.8 kV Bus Number 29308 Project will share same 13.8 kV Bus where exsting peaker is located.	
ES RFO 16.3 MW	**Project**	**Storage MW**	**Product Type**	**Locational Information**		
	Stanton Energy Reliability Center	1.3	RA Only (distribution)	**Point of Interconnection:** Barre Substation **Bus Name:** BARRE **Bus Number:** 24201		
	Western Grid	10	RA Only (distribution)	**Point of Interconnection:** Wakefield Petit 16 kV Distribution line (Santa Clara A Bank Substation) **Bus Name:** S.CLARA **Bus Number:** 24127		
		5	RA Only (distribution)			
EXISTING SCE STORAGE APPROVED AS ELIGIBLE IN D.14-10-045	**Project**	**Grid Domain**	**MW in Plan**	**MW Actually Installed**	**A-Bank Substation**	**Bus Numbers at the 230kV used by TSP and CAISO**
	Tehachapi Storage	Distribution	8	8	Windhub 220/66	29407
	Irvine Smart Grid-Community Energy Storage	Distribution	0.03	0.03	Santiago 220/66	24134
	Irvine Smart Grid-Containerized Energy Storage	Distribution	2	2	Santiago 220/66	24134
	Irvine Smart Grid-Residential ES Unit	Customer	0.06	0.06	Santiago 220/66	24134
	Large Storage Test	Distribution	2	2	Barre 220/66	24016
	Discovery Museum	Distribution	0.1	0.1	Villa Park 220/66	24154
	Catalina Island	Distribution	1	1	N/A	N/A
	V2G-LA AFB	Distribution	0.65	0.5	TBD	TBD
	Self-Generation Incentive Program	Customer	10.9	9.66	TBD	TBD
	Permanent Load Shifting	Customer	4.74	1.14	TBD	TBD
	Home Batter Pilot	Customer	0.08	0	N/A	N/A
	Distribution Energy Storage Integration 1	Distribution	2.4	2.4	Villa Park 220/66	24154

[1] Although these agreements are for 2 MW each, only 1 MW of the capacity will be comprised of storage as such only 1 MW is countable. (The remaining 1 MW is from renewable technology.)

[2] ACES Western Grid contract is an acceleration of the 2014 Energy Storage RFO Western Grid contract. As such, ACES Western Grid is not incremental to what is already counted for 2014 Energy Storage

Table 7: Locational Information for SDG&E's Energy Storage Resources

SDG&E's Energy Storage Projects Locational Information by Busbar & Attributes (MW)				
Domain	**Project Name**	**Capacity MW**	**Bus ID Number**	**Interconnection Substation**
Transmission	Lake Hodges Pumped Storage	40	22603	Lake Hodges LHM
Total Trasmission		**40 MW**		
Domain	**Project Name**	**Capacity / MW**	**Bus Number at Transmission Substation to which Distribution Circuit Connects**	**Interconection Substation**
Distribution	Escondido BESS 1	10	22256	Escondido
Distribution	Escondido BESS 2	10	22256	Escondido
Distribution	Escondido BESS 3	10	22256	Escondido
Distribution	El Cajon BESS 1	7.5	22208	El Cajon
Distribution	Borrego Microgrid Yard- SES1	0.5	22084	Borrego
Distribution	Pala Energy Storage Yard	0.5	22624	Pala
Distribution	Mission Valley- Skills Training Center	0.025	22496	Mission
Distribution	Clairemont	0.025	22136	Clairemont
Distribution	Poway	0.025	22668	Powey
Distribution	Borrego Springs CES	0.025	22084	Borrego
Distribution	Borrego Springs CES	0.025	22084	Borrego
Distribution	Borrego Springs CES	0.025	22084	Borrego
Distribution	Century Park CES	0.05	22372	Kearny
Distribution	Energy Inovation Center- Indoor	0.0045	22136	Clairemont
Distribution	Energy Inovation Center- Outdoor	0.01	22136	Clairemont
Distribution	San Diego Zoo	0.1	22868	Urban
Distribution	UCSD MESOM	0.006	22864	UCM
Distribution	Suites at Paseo (SDSU Private Dormitories)	0.018	21008	Stremview
Distribution	Del Lago Academy	0.1	22602	Olivenheim
Distribution	Ortega Highway 1243 SES1	1	22678	Margarita
Distribution	Ortega Highway 1243 SES2	1	22364	Margarita
Distribution	Pala Energy Storage Yard SES	1	22624	Pala
Distribution	Canyon Crest Academy	1	22581	North City West
Distribution	Borrego Microgrid Yard- SES2	1	22084	Borrego
Distribution	Santa Ysabel Substation	0.006	22736	Santa Ysabel
Distribution	Santa Ysabel Substation	0.03	22736	Santa Ysabel
Distribution	Del Lago Park & Ride	0.2		Felicita
Distribution	Integrated Test Facility	0.2	22256	Escondido
Total Distribution		**44.37 MW**		
Domain	**Project Name**	**Capacity / MW**	**Nearest Bus ID Number**	
Customer	SGIP/Non-SGIP Installed	14.64	Varies	Varies
Customer	SGIP/Non-SGIP In Progress	3.65	Varies	Varies
Customer	Permanent Load Shift Program	1.3	22864	Varies
Total Customer		**19.59 MW**		

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All energy storage projects described here are exclusive and incremental to any similar technologies that are accounted for as non-dispatchable DR (e.g. Permanent Load Shifting) embedded within the CEC's CEDU forecasts.

Adjustments due to actual and expected storage projects

The 50 MW of storage that D.13-02-015 ordered SCE to procure, and the 25 MW[30] of storage that D.14-03-004 ordered SDG&E to procure, are assumed to count towards the D.13-10-040 storage procurement target; they should not be double counted.

The 40 MW Lake Hodges storage project located in the San Diego area is assumed to satisfy a portion of SDG&E's share of the D.13-10-040 storage procurement target, and is reflected as doing so in Table 3.

3.2.5 Demand Response

Demand response (DR) programs whose impacts are not embedded in the CEDU 2016 forecasts include several event-based, price-responsive and reliability programs. Within the Draft 2017 A&S planning horizon, these programs should achieve full integration into the CAISO wholesale market and therefore count as supply-side DR. Per Decision D.14-12-024, and reinforced by D.15-11-042, the Commission found that, as of January 1, 2018, DR programs must be fully bifurcated. DR programs must also be either fully integrated into the CAISO wholesale market (supply-side DR) or embedded in the CEDU forecasts (load-modifying DR), otherwise these programs will no longer have capacity value and thus will no longer receive resource adequacy credit.[31] As of December 2016, SCE has integrated most of its DR programs into the CAISO market, while PG&E and SDG&E are working to integrate their program portfolios. With the adoption of D.15-11-042, CPUC staff anticipates that the IOUs will integrate their DR programs into the CAISO market by the January 1, 2018 deadline.

The DR Load Impact Reports[32] filed with the CPUC on April 1, 2016, and other supply-side DR procurement[33] incremental to what is assumed in the Load Impact Reports, serve as the basis for the supply-side DR planning assumptions included herein. Transmission and distribution loss-avoidance effects shall continue to be accounted for when considering the

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[31] That is, "supply-side" DR bids into the CAISO market and can receive resource adequacy credit, while "load-modifying" DR is embedded in the CED forecast and contributes by lowering the load forecast, thus lowering resource adequacy requirements.

[32] See Load Impact Report filings by each IOU on April 1, 2016, in R.13-09-011.

[33] Referring to procurement authorized by D.14-03-004 and DRAM, both described later in this subsection.

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load impacts that supply-side DR has on the system. The following table describes the total 2026 supply-side DR capacity assumptions, the details of which will be discussed in the remainder of this subsection.

Table 8: Demand Response Supply-side Modeling Assumptions Summary

DR not embedded in IEPR demand forecast (values in MW):	PG&E	SCE	SDG&E	All IOUs	Assumed Market Participation	Assumed to respond within 30 minutes
IOU Load Impact Report DR in 2026 (a)						
BIP	255.0	607.0	1.4	863.4	RDRR	Yes
AP-I		63.0		63.0	RDRR	Yes
AC Cycling Res (b)	54.0	218.0	11.5	277.0	PDR	Yes
AC Cycling Non-Res	1	40	3.1	44.1	PDR	Yes
CBP	120.0	141.0	12.2	263.0	PDR	No
DBP	0	0	0	0	PDR	No
AMP (DRC)	0	0		0	PDR	No
Other procurement program DR						
SCE LCR RFO (c), post 2018		5.0		5.0	RDRR	Yes
DRAM (d) (e) in 2017 and beyond				124.6	PDR[34]	No

Notes:
(a) Load Impact Report values are portfolio-adjusted August 2026 1-in-2 weather year condition ex-ante impacts at CAISO peak
(b) AC Cycling programs include Smart AC, SDP, and Summer Saver
(c) SCE LCR RFO refers to procurement authorized in D.14-03-004 with contract approved in D.15-11-041
(d) Demand Response Auction Mechanism is a 2-year pilot program of a maximum of one-year contracts
(e) For modeling purposes we assume capacity from existing programs described in the Load Impact Reports are a reasonable proxy for DR in 2026. It could turn out that by 2026, capacity from existing programs will be "retired" and "replaced" by significant growth in DRAM capacity.

[34] Although the 2017 DRAM solicitation could include a mix of Reliability Demand Response Resource (RDRR) and Proxy Demand Resource (PDR), for modeling we will assume it is all PDR absent more definitive information.

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In system resource planning studies, DR capacity based on the Load Impact Reports shall be counted using the portfolio-adjusted 1-in-2 weather year condition ex-ante forecast of monthly load impact at individual IOU peak.[35] This is consistent with the current DR capacity value calculation practice used in the CPUC's Resource Adequacy program. For the purpose of building load and resource tables, DR capacity shall be counted using the portfolio-adjusted 1-in-2 weather year condition ex-ante forecast of August load impact at CAISO peak.

For planning models that require hourly impacts of DR, the aggregate DR capacity for a given hour is assumed to be the sum of the capacity of all DR programs that operate during that hour. The capacity of a DR program outside its operating hours is assumed zero. For DR programs described in the Load Impact Reports, CPUC staff assumes the average capacity during operating hours specified in Resource Adequacy accounting rules (1pm to 6pm) is representative of DR capacity for all of a given program's operating hours (which may include hours outside of 1pm to 6pm). For a DR program described by other procurement processes (e.g. SCE LCR RFO and DRAM in Table 8), the capacity procured is the hourly capacity to be modeled during that program's operating hours. CPUC staff intends to improve upon this coarse assumption of hourly DR capacity in future planning cycles. Developing temporally granular assumptions about future DR capacity at this time would embody a lot of uncertainty due to DR bifurcation and other program changes happening within the DR proceeding (R.13-09-011).

For planning models that require assumptions about how DR would be expected to dispatch, DR is assumed to be available at times of system stress, subject to program operating constraints but not limited to the operating hours specified in the Resource Adequacy accounting rules. Near-term studies, such as one or two years ahead, may reasonably model DR operating constraints based on the current tariffs associated with each program.[36] Longer-term studies (e.g. more than five years ahead) should model DR operating constraints based on full integration into the CAISO market, implying that DR participates in the CAISO market using either the Proxy Demand Resource (PDR) or Reliability Demand Response Resource (RDRR) CAISO market constructs.[37] In the interest of ensuring comparability between studies conducted by different parties, CPUC staff

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[35] Previous iterations of the LTPP A&S document used monthly load impact figures at the CAISO peak. Going forward, modelers should use the individual IOU peak.

[36] To access IOU demand response tariffs please click on the following links.
PG&E: http://www.pge.com/en/mybusiness/save/energymanagement/index.page
SCE: https://www.sce.com/wps/portal/home/business/savings-incentives/demand-response/
SDG&E: http://www.sdge.com/save-money/demand-response/overview

[37] See http://www.caiso.com/participate/Pages/Load/Default.aspx

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recommends that modeling the expected dispatch of DR participating as PDR or RDRR use the following conventions:

- DR assumed to participate as RDRR[38]
    - shall trigger when market prices are $950/MWh
    - shall be dispatched for no more than 15 events and/or 48 hours total for June through September
    - shall be dispatched for no more than 15 events and/or 48 hours total for January through May and October through December
    - shall be consistent with other operating attributes specified by the RDRR construct, e.g. minimum load curtailment and run times
- DR assumed to participate as PDR [39]
    - shall trigger when market prices are $100/MWh
    - shall be dispatched for no more than 30 events and/or 120 hours total for the whole year
    - shall be consistent with other operating attributes specified by the PDR construct, e.g. minimum load curtailment and run times

Any party conducting Local Capacity Reliability Area planning studies must also make certain assumptions about available DR capacity under the grid conditions being studied. The CAISO conducts two types of planning studies related to Local Capacity Reliability Areas: Long-term Local Capacity Requirement (LCR) studies that study 10 years ahead and are conducted within the CAISO's annual Transmission Planning Process,[40] and Local Capacity Technical (LCT) Studies that study 1-5 years ahead and are used to inform the CPUC's Local Resource Adequacy requirements.[41] In these studies, the CAISO considers whether resources physically located within a Local Capacity Reliability Area can respond to a "first contingency".[42] The Resource Adequacy Rulemaking R.14-10-010 is currently considering whether to change Local Resource Adequacy rules in order to create a

[38] Based on RDRR attributes described here: http://www.caiso.com/Documents/ReliabilityDemandResponseResourceOverview.pdf

[39] It is difficult to know in advance if these specific modeling conventions for RDRR and PDR will result in models the produce realistic dispatches of DR. Modelers may use some discretion in adjusting trigger price and event or hour caps in order to achieve realistic dispatches of DR. Any adjustments must be transparently documented and shared with all parties.

[40] http://www.caiso.com/Documents/RevisedDraft2015-2016TransmissionPlan.pdf

[41] http://www.caiso.com/informed/Pages/StakeholderProcesses/LocalCapacityRequirementsProcess.aspx

[42] The terms "first contingency" and "second contingency" were described in decision D.14-03-004, and the May 21, 2013 revised scoping ruling found here: http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M065/K202/65202525.PDF

requirement regarding how quickly DR resources that are physically located in Local Capacity Reliability Areas would need to respond in order to count as Local RA capacity and whether there is a way to pre-dispatch slower responding resources so that they could also be counted. The CPUC's Resource Adequacy accounting rules currently have no requirement related to "first contingencies" or response times for a resource to count as Local Resource Adequacy capacity. If a new methodology is approved by the CPUC in 2016 it should be used as the basis for counting resources that meet Local Capacity Requirements in future long-term planning cycles.

Based on current program forecasts, CPUC staff estimate that in 2026, throughout the CAISO area, 1,259 MW of DR would be available to count towards Local RA capacity and meet LCR needs – to the extent that the DR is physically located within Local Capacity Reliability Areas. CPUC staff developed the 1,259 MW estimate by aggregating DR programs included in the Load Impact Reports that can deliver load reductions in 30 minutes, or less, from customer notification (which amounts to 1254 MW) with DR specifically procured to meet local reliability needs (5 MW). CPUC staff used the Load Impact Reports' August 2026 portfolio-adjusted 1-in-2 weather year condition[43] ex-ante forecast of load impact coincident with CAISO system peak. DR specifically procured to meet local reliability needs is the 5 MW of DR that was procured pursuant to SCE's LCR RFO (approved, by D.15-11-041).[44] This 5 MW is assumed to be incremental to the 928 MW[45] of 30-minute-responsive DR in SCE's territory as calculated from the Load Impact Reports.

In addition to DR specified in the Load Impact Reports and DR procured through SCE's LCR RFO, the CPUC has approved 56.2 MWs of SCE DR contracts for system RA capacity procured through the pilot Demand Response Auction Mechanism (DRAM) for deliveries starting January 1, 2017 through the end of 2017, for a mixture of system, local and flexible RA capacity[46]. PG&E's and SDG&E's 2017 DRAM auctions concluded in October 2016.

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[43] Note that although Local Capacity Requirement assessments study 1-in-10 year weather conditions, we assume DR capacity based on 1-in-2 year weather ex-ante impacts because this is currently the basis of the Qualifying Capacity value given to DR for both system and local Resource Adequacy compliance purposes.

[44] Note that the CAISO's recently proposed Business Practice Manual (BPM) change (https://bpmcm.caiso.com/Pages/ViewPRR.aspx?PRRID=854&IsDlg=0) calls into question whether the DR procured to meet local reliability needs through SCE's LCR RFO will be counted by the CAISO as eligible to meet local reliability needs. This is because the CAISO's proposed BPM change imposes a 20 minute response time on local DR resources as opposed to the 30 minute response time assumed in D.14-03-004 which authorized SCE's LCR RFO and D.15-11-041 which approved the DR resource.

[45] 935 MW = 611 MW of base interruptible + 66 MW agricultural pumping + 218 MW residential ac cycling + 40 MW non-residential ac cycling

[46] Energy Division approved SCE AL 3442-E via disposition letter.

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However, both IOUs were ordered by the CPUC to procure more DRAM capacity than they had originally demonstrated. PG&E's 2017 DRAM auction resulted in the procurement of 56.4 MW, and SDG&E's resulted in the procurement of 12 MW. That auction has not yet occurred, so studies needing to make an assumption about DRAM capacity in 2017 should assume the minimum procurement target of 22 MW is procured and that the DRAM capacity will be used for system RA capacity. Note that at this time the pilot DRAM program is structured for contracts with lengths of up to one year, so long term planning assumptions can make no reasonable statement about expected long-term DRAM capacity. Therefore, CPUC staff continues to assume that the bulk of DR capacity expected to be present in the long term is best approximated by the DR projections in the Load Impact Reports. In the long term it may be possible that the capacity from existing DR programs described in the Load Impact Reports will be "retired" and "replaced" by significant growth in DRAM capacity.

For technical studies that require modeling DR capacity at individual transmission-level bus-bars, DR capacity should be allocated to bus-bar using the method defined in D.12-12-010, or to specific bus-bar locations provided by the IOUs. CPUC staff expects that the IOUs will provide updated bus-bar allocations to the CAISO for use in the 2017-18 TPP. The bus-bar locations also help determine which portion of aggregate 30-minute-responsive DR capacity within an IOU planning area is physically located within a Local Capacity Reliability Area.[47]

Given the uncertainty as to the DR amount that can be relied upon for mitigating first contingencies, the CAISO's 2014-15 and 2015-16 TPP Base Local Capacity Reliability Area studies examined two scenarios: one consistent with the 2012 LTPP Track 4 DR assumptions and one consistent with the 2014 LTPP DR assumptions of available 30-minute-responsive DR. CPUC staff expects that a similar two scenario approach will be used in the 2017-2018 TPP; that is, the CAISO would study one scenario assuming a base level of DR capacity[48] to meet first contingencies, followed by a second scenario assuming full availability of the 30-minute-responsive DR described in Table 8 above – to the extent that DR is physically located in the Local Capacity Reliability Area being studied.

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[47] The CAISO noted that DR eligible for inclusion in the TPP must be allocated to bus-bars and must be a CAISO integrated resource, meaning that resource is mapped to specific PNodes.

[48] The CAISO has received updated information from SCE that increases the base level of DR capacity to meet first contingencies from what was assumed in previous TPP cycles. This is described in the CAISO's Draft 2016-2017 Transmission Planning Process Unified Planning Assumptions and Study Plan, p. 27 (http://www.caiso.com/Documents/Draft20162017StudyPlan.pdf.)

3.2.6 RPS Portfolios

Historically, a set of additional future renewable resources needed for compliance with the state's RPS program were specified for each scenario articulated in the Assumptions and Scenarios document. These portfolios were produced by Energy Division staff using the RPS Calculator, a publicly vetted spreadsheet tool.

Various studies are underway that could inform planning beyond the 33% RPS goal. Thus, various pathways may eventually be identified that lead to a beyond-33% goal. To include a portfolio of increased renewables for long term planning would be to presuppose the conclusions of the various studies underway, particularly as it relates to potential infrastructure authorizations needed to meet future goals. Thus, no new RPS portfolios are specified this year for additional resources needed to meet RPS goals.

- The information-only 50% RPS special study completed by CAISO as a part of their 2015-16 TPP process suggested that no additional transmission may be needed to enable the state to achieve its RPS policy goal (though additional transmission may be economically justifiable).
- The IRP process is expected to include a new and more appropriate methodology for developing RPS portfolios than the RPS Calculator. As a result, it would be more prudent to incorporate the results of the IRP process in the 2018-2019 TPP.
- IOUs under CPUC jurisdiction for purposes of compliance with the states RPS program are generally long on RPS resources and may not require much additional procurement, if any, to achieve their 50% targets by 2030. A smaller need for new generation reduces the urgency of studying the transmission upgrades that might be required to enable that generation to serve load. In the 2018-19 timeframe, IRP is expected to address the question whether there is need for additional RPS procurement over and beyond the mandated 50% RPS in 2030.

For use in the 2017-18 TPP process, the CAISO anticipates updating the prior RPS forecast with projects that have begun construction since issuance of the 2016 LTPP A&S document in May 2016.

3.2.7 Technical Attributes of Solar PV projects

The physical configuration of solar PV projects influences the shape of their hourly generation profiles and has material impact on the outcome of resource planning studies. Two important physical attributes are the mounting-type and the DC-AC inverter loading ratio. Mounting-type includes the following:

- Fixed-tilt: stationary panels tilted, south-facing

- Tracking, 1-axis: panels track the sun on a single axis from East to West
- Tracking, 2-axis: panels track the sun on a dual axis (these projects are rare)[49]

The ratio of panel capacity to inverter capacity is the DC-AC inverter loading ratio and a higher ratio tends to flatten or clip the production profile of a PV project. Industry practice for PV installations has been to install a panel capacity larger than the inverter capacity to compensate for de-rate factors such as DC-AC conversions and losses and to maximize economic value.

Table 9: Contracted Solar PV Capacity (MW) & Capacity-Weighted Average ILR, By Mounting-Type

	PG&E	SCE	SDG&E
Fixed-tilt capacity	2,043	876	395
Fixed-tilt ILR	1.26	1.24	1.29
Tracking capacity	1,406	3,334	938
Tracking ILR	1.28	1.31	1.29

Table 9 summarizes the IOU-contracted solar PV capacity (as of June 2015) for each of the three major IOUs and the capacity-weighted average inverter loading ratio separated by mounting-type.[50] "IOU-contracted" means the project has a CPUC-approved power purchase contract and it can be an existing online project or a project still under development. Because these projects have a CPUC-approved power purchase contract, their physical attributes are known and the projects are likely to be completed successfully.

For planning purposes, studies need to assume a mounting-type and inverter loading ratio for "generic" projects. The trends of mounting-type and inverter loading ratio in the most

[49] Dual-axis tracking solar PV projects represent a tiny portion of tracking projects CAISO-wide, just 12 MW of capacity out of over 5,600 MW of IOU-contracted projects. For simplicity, the tables in this section treat dual-axis projects as if they were single-axis projects.

[50] This data was aggregated from individual project data obtained from the CPUC Energy Division's RPS Contract Database (formerly known as Project Development Status Reports), June 2015 vintage, and data request responses from each IOU that provided physical attribute information for all IOU-contracted projects. Projects that were from these two data sources are either existing online projects or projects in development that are assumed to meet the criteria for "commercial" projects in the RPS Calculator. Some of these projects are in fact IOU-owned. The aggregated data does not identify market-sensitive information about individual solar PV projects.

recent IOU-contracted projects can be used as a proxy for the likely physical attributes of "generic" projects. Table 10 below categorizes IOU-contracted projects by online year and identifies the amount of each mounting-type by capacity and percentage of total capacity.

Table 10: Contracted Solar PV Capacity (MW) Grouped By Mounting-Type & Online-Year

	any year	%	2014 or later	%	2015 or later	%
PG&E						
Fixed-tilt	2,043	59%	1,560	61%	176	17%
Tracking	1,406	41%	1,000	39%	831	83%
SCE						
Fixed-tilt	876	21%	836	21%	525	15%
Tracking	3,334	79%	3,215	79%	3,040	85%
SDG&E						
Fixed-tilt	395	30%	17	3%	17	7%
Tracking	938	70%	552	97%	225	93%
3 IOUs						
Fixed-tilt	3,315	37%	2,414	34%	718	15%
Tracking	5,678	63%	4,767	66%	4,097	85%

The newest projects (online in 2015 or later) tend to consist of tracking mounting-types. Based on this trend, "generic" projects selected by the RPS Calculator shall be assumed 15% fixed-tilt and 85% tracking.[51] There does not appear to be a clear difference in inverter loading ratios for newer vs. older projects. Therefore, "generic" projects shall be assumed to have inverter loading ratios similar to the capacity-weighted average of all IOU-contracted projects. Table 11 below summarizes the mounting-type and inverter loading ratio assumptions for "generic" (i.e. not yet contracted) projects. The percentage represents the share of all generic solar PV projects.

[51] Note that this subsection intends to override certain technical attributes of generic solar PV assumed by the RPS Calculator on the basis that trends in solar PV procurement are likely better indicators of the technical attributes of generic solar PV that would be realized in future procurement. This is partly because the RPS Calculator makes some simplifying assumptions about solar PV attributes in order to complete its calculations in a timely manner.

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Table 11: Generic Solar PV Project Mounting-Type & ILR Assumptions

	PG&E	SCE	SDG&E
Fixed-tilt % share	15%	15%	15%
Fixed-tilt ILR	1.26	1.24	1.29
Tracking % share	85%	85%	85%
Tracking ILR	1.28	1.31	1.29

It is expected that technical modelers, especially those conducting production cost simulations, need to create 8760 hour annual energy profiles for bulk solar. Profile creation requires three key types of information: an 8760 hour solar irradiance profile varying by location, project installed capacity and location, and the technical attributes of each project. Solar irradiance data can be sourced from public datasets such as National Renewable Energy Laboratory's Solar Prospector[52] or Solar Integration National Dataset Toolkit.[53] Project installed capacity and location are provided by the RPS portfolio created by the RPS Calculator. Again, the technical attributes of bulk solar PV projects are specified by Table 9 and Table 11, above.

However, there is a potential for the annual energy outcome predicted by the RPS Calculator to be different from the annual energy profiles created by technical modelers and incorporating the technical attributes specified above. This is because the RPS Calculator uses simplified weather and technical attribute assumptions[54] to develop its RPS portfolio that meet a certain annual energy target and satisfy the desired RPS requirement (e.g. 50%). For consistency purposes the following method is adopted:

> Leave the installed capacity provided by the RPS portfolio unchanged. Create the annual energy profiles incorporating the technical attributes specified in this section and use those profiles as inputs to production cost simulations. This may result in annual energy outcomes somewhat different from what the RPS Calculator

[52] http://maps.nrel.gov/prospector

[53] http://www.nrel.gov/electricity/transmission/sind_toolkit.html

[54] http://www.cpuc.ca.gov/RPS_Calculator/

predicted (e.g. annual RPS energy percentage ended up at 48% or 52% instead of 50%).

Technical modelers are expected to document all details about how they create 8760 hour annual energy profiles for bulk solar, and how the profiles are used in technical studies (e.g. production cost simulations).

3.2.8 Nuclear Retirements

Both units of the Diablo Canyon Power Plant (DCPP) are proposed to be decommissioned, subject to Commission approval, and thus should be modeled as coming offline.

Unit 1 of DCPP is expected to retire on November 2, 2024 and Unit 2 is expected to retire on August 26, 2025.[55]

3.2.9 Once-Through-Cooled Technology Retirements

The default assumption is that power plants using once-through cooling (OTC) technology retire according to the current State Water Resources Control Board (SWRCB) OTC compliance schedule, or sooner, per generation owners' latest implementation plans submitted to the SWRCB.

Moss Landing

The original compliance date for Moss Landing under the OTC compliance schedule was December 31, 2017. However, a settlement agreement signed by Dynegy (the owner of Moss Landing) and the SWRCB staff in October 2014 extended this compliance date to December 31, 2020 for Units 1 and 2 and Units 6 and 7. This OTC amendment, per the settlement agreement, was approved by the SWRCB on April 7, 2015 and is now in effect. The plant's ownership stated its intent to install technology on Units 1 and 2 which will allow them to continue operating at a projected maximum capacity factor of 78%. Dynegy filed its 90-day notice with the CAISO to make known that it intends to retire Moss Landing Units 6 and 7 in January 2017. Therefore, staff assumes that by December 31, 2020 Units 1 and 2 will be successfully retrofitted and that at the end of January 2017 Units 6 and 7 will retire.

Encina

The OTC compliance date for all five Encina units is December 31, 2017. The Commission approved a 500 MW re-power of all Encina units into a proposed Carlsbad Energy Center. That Commission Decision was contested, but was recently affirmed by the Court of Appeal of the State of California. NRG (the owner of Encina) intends to shut down and permanently

[55] See A.16-08-006

retire Encina Unit 1 by February 2017. Encina Unit 1 should be modeled as coming offline February 2017 and the rest of the units coming offline December 31, 2017, subject to potential SWRCB extension, with Carlsbad coming online to replace them in Q4 2018. [56]

3.2.10 Renewable and Hydro Retirement Assumptions

Retirement assumptions are based on a facility's age as a proxy for determining a facility's remaining operational life. In previous versions of the LTPP A&S document, three options for renewable retirement levels were provided, which corresponded to "low-", "medium-", and "high-" levels of renewable retirement assumptions. In the 2017 A&S, it is assumed there will be no renewable retirements within the planning horizon.

3.2.11 Other Retirement Assumptions

Retirement assumptions are also based on facility age as a proxy for determining a facility's operational life. Similarly to renewable and hydro retirement assumptions, the operational history of non-renewable/hydro facilities will not be considered in this planning cycle. A "Low" level of retirement assumes that "Other" resource types stay online unless there is an announced retirement date. A "Mid" level assumes a retirement schedule based on resource age of 40 years or more. A "High" level assumes a retirement schedule based on resource age of 25 years or more. Facilities which have an existing contract that runs beyond their assumed retirement age shall instead be assumed to operate until the expiration of the contract. Thus, a 38 year old facility in the "Mid" level that has a three year contract should be assumed to retire at 41 years once that contract expires. Commission staff will periodically request confidential procurement data from the utilities to screen for such facilities. "Other" includes all resources whose retirement assumptions are not explicitly described above – for example, peaker and cogeneration facilities. The default assumption for planning studies is a "Mid" level of retirement for "Other" resources.

"Cold shutdowns" or "Mothballed" Facilities

Generator owners that announce they will shut down their facilities, but which do not send notifications of retirement,[57] will be treated as follows: we will assume that, if economic conditions merit, these facilities could be made operational. As such, they will be considered existing resources, subject to the retirement rules.

[56] http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=11675

[57] As with what has happened when Calpine announced it would not operate the Sutter Energy Center Plant for the rest of 2016.

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Long Beach Peakers

From a technical and operational perspective, the Long Beach peaker plants can remain in operation at least through 2025 due to recent refurbishments. These peaker plants' economic lifespan, however, depends on whether this facility can successfully re-contract once its current contract expires in 2017. The planning assumptions in studies informing D.14-03-004 and the 2015-16 CAISO TPP assumed that the Long Beach Peakers would retire at the end of its current contract. In contrast, the retirement assumption specified in the Rulings on 2014 LTPP planning assumptions dated March 4, 2015 assumed that the Long Beach Peakers would remain online at least through 2025. The May 2016 LTPP A&S[58] assumed now assume that the Long Beach Peakers will would retire by December 31, 2047, which is a date based on the year (2007) these peakers were refurbished and our "Mid" level 40 year lifespan assumption.

3.2.12 Imports and Exports

For the purposes of load and resource tables the default value for imports shall be based on the CAISO Available Import Capability for loads in its control area. This import capability is equal to the CAISO Maximum Imports minus Existing Transmission Contracts (ETCs) outside its control area, and is published on its website annually.[59] For 2017 the total import capability is calculated at 11,310 MW.[60] The 11,310 MW value should be used throughout the planning horizon being modeled. An alternative assumption is historical expected imports as calculated by the CEC.[61]

Technical planning studies require a more nuanced approach to accounting for imports. In the 2010 and 2012 LTPP studies the CAISO used a tool to calculate California statewide, and CAISO area maximum imports. That tool calculated import limits for each scenario being studied based on inertia changes in the Southern California Import Transmission (SCIT) area due to increased penetration of renewable resources and retirement of generation resources with inertia. It is anticipated that CAISO will update this tool and use it for the LTPP studies envisioned by this document for use in future planning studies.

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[58] http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M162/K005/162005377.PDF

[59] 2016 Import Capability Assignment Process Steps 6 and 7; found here http://www.caiso.com/FASTSearch2/Pages/allresults.aspx?k=import%20capability%20step%206

[60] For the source of the 11,665 MW of total import capability, look for "2016 Import Allocations" under "Import Allocation" here: "https://www.caiso.com/planning/Pages/ReliabilityRequirements/Default.aspx Click on "Step 6: 2016 Assigned and Unassigned RA Import Capability on Branch Groups".

[61] As described in Appendix D, http://www.energy.ca.gov/2012publications/CEC-200-2012-003/CEC-200-2012-003.pdf

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For technical planning studies requiring information about infrastructure, resources, and loads outside of the CAISO area, the Transmission Expansion Policy Planning Committee (TEPPC) 2026 Common Case dataset should be used.

In regards to exports, the LTPP planning assumptions have historically been silent on the potential quantity of exports. The CAISO has, in the past, imposed a modeling constraint of "no net exports;" this reflects historical practice. As the system moves forward with regionalization efforts, however, further work is required to establish appropriate assumptions on the potential exports in different planning futures. In the Draft 2017 A&S, zero net exports will be deemed as the Low-case; 2000 MW of net exports will be considered the Mid-case; and 5000 MW of net exports will be incorporated as the High-case. The net export constraint assumed by modelers should be set at the Mid-case in all but the Interregional Coordination Scenario. For the Interregional Coordination Scenario the net export constraint should be set at the High-case.

3.2.13 Regional Generation Requirement and Frequency Response Constraints

In previous LTPP studies using production cost simulation models, a regional generation requirement constraint was imposed. This was modeled as a requirement for at least 25 percent of load to be met by generation from local resources within specific geographic areas in California. This constraint served as a crude proxy for ensuring sufficient local generation was online to supply both frequency response and the ability to respond to contingencies. Given recent infrastructure upgrades including new peaker resources in Southern California that enhance the ability to respond to contingencies, the 25 percent regional generation requirement constraint is removed. However, the need to supply sufficient frequency response must still be met, and this will be modeled by a new constraint in production cost simulation models that would ensure each balancing area can meet its obligations under the new NERC BAL-003-1 frequency response standard. According to the NERC BAL-003-1 standard and the CAISO's Frequency Response Stakeholder Process, the CAISO's current frequency response obligation is 258 MW/0.1 Hz, which can be interpreted to mean that the CAISO balancing area must have 752 MW of headroom at all times.

For consistency across different studies using production simulation models, modelers are directed to implement constraints to represent the CAISO balancing area's compliance with NERC BAL-003-1 as follows:

1. 50% of the headroom requirement (376 MW) is assumed to be met by hydro resources (excluding pumped hydro storage). However, no modeling constraint will be imposed on hydro. This is based on CAISO's operational experience that hydro can respond to under-frequency at any time without imposing explicit constraints on hydro operations.

2. 50% of the headroom requirement (remaining 376 MW) is assumed to be met by storage (excluding pumped hydro storage) and/or online combined cycle resources.
   a. Storage units assumed to provide flexibility services (as described in the storage assumptions section of this document) are allowed to meet the headroom requirement on a MW-for-MW basis, up to the available storage headroom.
   b. Combined cycle units can provide 0.08 MW toward the headroom requirement for each MW of online capacity, up to the available combined cycle unit head room.
3. Geothermal and nuclear typically operate at full load and are assumed to not contribute towards meeting the frequency response obligation.
4. The headroom requirement applies for all 8760 hours of the typical one-year production cost simulation model.

3.2.14 Existing Procurement Authorizations

Planning Assumptions Made With Pending Applications Data

Decision 15-11-041 approved the results of SCE's Local Capacity RFO (A.14-11-012) for the Western LA Basin pursuant to D.13-02-015 and D.14-03-004.

Decision 16-05-050 approved a portion of the results of SCE's Local Capacity Requirements RFO (A.14-11-016) for the Moorpark sub-area. A decision on the remaining resources is expected in 2017; the projects that would help satisfy Moorpark's LCR are those with "location": "Goleta" illustrated in Table 12.

SDG&E filled 500 MW of its 800 MW Track 4 LCR authorization via its power tolling agreement with Carlsbad Energy Center LLC.

The complete set of planning assumptions for existing LCR procurement authorizations are specified in Table 12, below, and should be used in all planning studies. These assumptions should also be utilized to inform CAISO TPP studies.

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Table 12: Procurement Assumptions With Approved and Pending Applications

Decision	Capacity (MW)	Assumed online	Location	Description
Approved: D.15-11-041	640	2020	Alamitos, Long Beach	Combined cycle gas turbine
Approved: D.15-11-041	644	2020	Huntington Beach	Combined cycle gas turbine
Approved: D.15-11-041	98	2020	Stanton	Peaker turbine
Approved: D.15-11-041	124	2020	W. LA Basin (Procured via SCE's LCR RFO)	Energy efficiency
Approved: D.15-11-041	5	2018	W. LA Basin (Procured via SCE's LCR RFO)	Demand response
Approved: D.15-11-041	38	2018	W. LA Basin (Procured via SCE's LCR RFO)	Distributed generation solar PV
Approved: D.15-11-041	135	2018	W. LA Basin (Procured via SCE's LCR RFO)	Battery storage – BTM
Approved: D.15-11-041	29	2020	W. LA Basin (Procured via SCE's LCR RFO)	Thermal storage – BTM PLS
Approved: D.15-11-041	100	2021	Long Beach (Procured via SCE's LCR RFO)	In-front-of-the-meter Battery storage – transmission-connected
Approved: D.16-05-050	6	2020	Big Creek/Ventura (Moorpark Sub-Area)	Energy efficiency
Approved: D.16-05-050	6	2018	Big Creek/Ventura (Moorpark Sub-Area)	Distributed generation solar PV
Approved: D.16-05-050	262	2020	Puente, Big Creek/Ventura (Moorpark Sub-Area)	Peaker gas turbine
Pending: A.14-11-016	0.5	2018	Goleta (Moorpark Sub-Area)	In-front-of-the-meter Battery storage transmission-connected
Approved: D.14-02-016	300	2016	Pio Pico site	Peaker gas turbine
Approved: D.15-11-041	500	2018	Encina site (Carlsbad)	Peaker gas turbine
Authorized / Pending	25	2019	San Diego	Battery storage – transmission-connected
Pending: A.16-03-014	18.5	2018	San Diego	Energy efficiency
Pending: A.16-03-014	20	2019	San Diego	Energy Storage

Note that the 264 MW (100 MW + 35 MW + 29 MW) of energy storage projects included in Table 12 also counts toward achievement of the storage procurement target in D.13-10-040 and are therefore counted in Table 6. These 264 MW are shown here is listed for completeness, but should not be modeled twice (double counted). Also note that the table above does not encompass the entirety of SDG&E's existing LCR procurement authorizations. Pursuant to D.15-05-051, SDG&E's residual procurement authority limited to preferred resources or energy storage, was revised to 300 MW. On March 30, 2016 SDG&E filed an Application (A.16-03-014), seeking approval of a 20 MW energy storage contract and 18.5 MW of EE projects. Assuming SDG&E's Application is approved, SDG&E's remaining preferred resource authorization is 261.5 MW.

Since the portfolio of resources necessary to meet SDG&E's authorization has not been determined, power flow studies should exclude the authorized but unprocured energy capacity. To the extent power flow studies identify an LCR need, the remaining 261.5 MW of authorized LCR procurement need should be considered first before authorizing new resources.

The energy efficiency, demand response, and distributed generation resource assumptions listed in Table 12 above represent incremental LCR procurement and are therefore assumed to be incremental to the other energy efficiency, demand response,[62] and distributed generation assumptions described earlier in this document.

Interaction of LCR procurement and storage target

Some of the storage projects included in the applications that would fill existing LCR procurement authorizations are assumed to satisfy the D.13-10-040 storage procurement target; these storage projects are noted in Table 12. Technical studies shall not double count these resources. Table 3 in the Energy Storage section (3.2.4) of this document does not include any adjustment to reflect how existing LCR procurement authorizations are assumed to satisfy the D.13-10-040 storage procurement target. SCE's share of the D.13-10-040 storage procurement target for customer-side storage is 85 MW. However, the CPUC via D. 15-11-041 approved SCE contracts to procure 164 MW[63] of customer-side storage via its LCR procurement Application. This results, combined with other customer-side storage procurement, in SCE exceeding its customer-side storage target (per D.13-10-040) 159.42 MW. Technical studies should therefore assume that SCE's share of the D.13-10-040 storage procurement target for customer-side storage is completely filled by its proposed LCR procurement. Note that all of the 164 MW of customer-side storage represented by SCE's LCR application should count as capacity in power flow studies because this storage is expected to be procured specifically to satisfy local capacity requirements.

[62] The "5 MW 2019 W. LA Basin Demand response" project included in Table 12 is the same 5 MW of incremental DR described in Section 3.1.7 and should therefore not be double counted.

[63] These 164 MW include the Ice Bear (28.64 MW project) and two "Hybrid Electric, stern" (85 MW + 50 MW) projects. See Table 6.

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SCE's share of the D.13-10-040 storage procurement target for transmission-connected storage is 310 MW. However, SCE proposes to procure about 100 MW of transmission-connected storage in its LCR procurement applications. Therefore technical studies should assume that SCE's share of the D.13-10-040 storage procurement target for transmission-connected storage is partly filled by its proposed LCR procurement of 100 MW and the remaining share of the storage procurement target is 210 MW.

SDG&E's share of the D.13-10-040 storage procurement target for transmission-connected storage is 80 MW. After accounting for existing project Lake Hodges, the remaining share is 40 MW. Note that all of the 25 MW of transmission-connected storage represented by SDG&E's required LCR procurement, per D.14-03-004, counts as capacity in power flow studies because this storage is expected to be procured specifically to satisfy local capacity requirements.

3.3 Other Assumptions

3.3.1 The Second Planning Period

Planning studies which target years within the second planning period (2027-2036) will use simplified planning assumptions. Generally, these assumptions reflect extrapolation of the approaches of the first planning period.

- Net (managed) load growth will be extrapolated using the average, annual compound growth rate from the prior period. Only the net load will be extrapolated (i.e. the forecast load, after demand side adjustments such as AAEE), rather than extrapolating individual load or demand assumptions. The formula for calculating the growth rate is…

  $$GrowthRate = \left(\frac{NetLoad_{2026}}{NetLoad_{2016}}\right)^{\frac{1}{(2026-2016)}} - 1$$

  …where Net Load is the gross load forecast minus AAEE. This annual growth rate is then applied to the 2026 Net Load to calculate the Net Load for 2027-2036.
- Resource retirements will be calculated based on resource age or other characteristic, as described for the first planning period of each scenario.
- Resource additions (except renewable resources) will be calculated based on known and planned additions for all scenarios.
- Imports will be assumed to remain constant from the 2026 value through the second planning period.

- Dispatchable DR will be assumed to remain constant from the 2026 value through the second planning period.
- The analytical work being undertaken in the Integrated Resource Planning Proceeding (R.16-02-007) will be making a projection of BTM PV beyond 2026. In the meantime, the BTM PV assumptions contained in CEDU 2016 should be used in long-term planning.

3.3.2 Deliverability

Resources can be modeled as Energy-Only or Fully-Deliverable. The CAISO's TPP, for purposes of identifying needed policy-driven transmission additions, uses renewable resource portfolios provided by the CPUC that historically require full-deliverability. As an alternative to full deliverability and in order to better allow for analysis of options for providing additional generic capacity, in Energy-Only portfolios any additional resource will only be assumed to be Deliverable if it meets one of two criteria:

(1) Fits on the existing transmission and distribution system,[64] including minor upgrades,[65] or new transmission approved by both CAISO and CPUC, or

(2) It is a baseload or flexible resource.[66]

This assumption is only for study and planning purposes and does not prejudge any future CPUC decisions on transmission or resource approvals.

3.3.3 Price Methodologies

The same methodologies that were used in the 2014 LTPP proceeding and the 2016 LTPP proceeding should be used for the Draft 2017 A&S.

Natural Gas

[64] For this purpose, "fits" refers to the simple transmission assumptions listed in the "CAISO_Tx_Inputs" tab of the RPS Calculator. Staff shall collaborate with the CAISO to update these transmission assumptions and apply them to the resource portfolios.

[65] Minor upgrades do not require a new right of way.

[66] Flexibility currently does not have a standard definition, but a definition will be established either in this proceeding or in the Resource Adequacy proceedings (the current proceeding is R.14-10-010. Generally speaking, baseload resources are those that provide a constant power output, such as a nuclear plant, while flexible resources are those that can respond to dispatch instructions. There is some overlap between these two categories, for example a baseload design combined cycle plant could provide some flexibility.

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The CEC's Natural Gas Reference Case as put forward in CEDU 2016 shall be used as the base for calculating natural gas prices. This price series was constructed to be consistent in baseline assumptions with the CED forecast and therefore the two are congruent for planning purposes.

Greenhouse Gas

The GHG price forecast as put forward in the 2016 IEPR shall be used as the base for calculating GHG prices.

4 Planning Scenarios

4.1 2017 Planning Scenario – Reliability Scenario

The Draft 2017 A&S document contains information regarding a single scenario: the Reliability Scenario. The Reliability Scenario maps closely to the Infrastructure Investment Scenario articulated in the previous version of the LTPP A&S finalized as of May 2016. This is for use in long-term electric system planning for the state of California, as well as for use as an input in the CAISO's 2017-18 TPP studies, set to commence in early-2017.

Previous versions of the LTPP Assumptions & Scenarios document contained multiple scenarios used to evaluate different potential futures for California's electric system. Typically, these scenarios contained varying assumptions used for reliability, economic, and policy-driven analyses. For example, previous LTPP A&S documents contained scenarios for analysis of possible futures that contained assumptions for higher RPS generation targets, greater regional coordination, or higher BTM PV adoption. Analyses of these scenarios could have highlighted the need for different investments, such as additional transmission infrastructure.

The Draft 2017 A&S document only contains information regarding a single reliability scenario: the Reliability Scenario. Policy-driven analysis historically focused on identifying any transmission infrastructure needed to support the state's Renewable Portfolio Standard (RPS) program. By mutual agreement between the CPUC, CAISO, and CEC, no RPS-related policy-driven analyses to identify new infrastructure needs beyond what is necessary to support a 33% RPS scenario are being provided by the CPUC in this document for consideration in long-term planning and for use by the CAISO for its 2017-18 TPP.

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What this scenario helps us study: This scenario will be provided to the CAISO as the base-case to be used in the 2017-18 Transmission Planning Process (TPP) studies.[67]

Why this scenario is worthwhile to study: The renewable resources portfolio plays an integral role when modeling the electric system. The CAISO and the CPUC have a memorandum of understanding under which the CPUC provides a renewable resource portfolio for CAISO to analyze in the CAISO's annual TPP. The TPP analyzes the transmission system and determines the need for new transmission resources to ensure system reliability and meet policy goals.

This scenario updates critical operational variables of the transmission system but does not forecast an increase in renewable resources beyond the 33% goal used in previous trajectory scenarios. CPUC and CAISO staff believes that it would be inappropriate to plan significant transmission expansion investments to access increased renewable resources before the CPUC has fully analyzed alterative renewable portfolios and selected a preferred course of action for infrastructure investment enhancements. If a fully-deliverable portfolio consisting of a RPS percentage greater than 33% is studied by the CAISO as part of its "base-case" TPP scenario, such a portfolio would likely result in a CAISO assessment indicating that new transmission capacity is needed to bring renewable energy, beyond the 33% RPS threshold, to market. Thus, it would be imprudent to generate a renewable portfolio that might trigger new policy-driven transmission investment until more information is available.

Similarly, a new 33% RPS portfolio generated by the updated RPS calculator would be based upon increasing customer generation and declining IEPR CED load forecasts and therefore could be based upon a lower RPS net short than the RPS portfolio used in the 2016-17 TPP. Such a portfolio might not support currently approved transmission projects that will be needed to reach 50% RPS goals. Thus, no new renewable portfolio will be provided in the Draft 2017 A&S which may compel the CAISO to reexamine previously approved transmission investment decisions until more information is available.

Submitting the Reliability Scenario for the CAISO to study as part of the 2017-18 TPP therefore ensures that the CAISO study results will reflect known transmission needs, not transmission needs based on speculative renewable portfolios. On a practical level,

[67] The CAISO authorizes new transmission infrastructure based on studies of the Base-Case scenario; via reply comments on the Draft Assumptions and Scenarios document CAISO stated: "The CAISO strongly supports staff's recommendation to use the 33% RPS portfolios for the 2016-17 transmission plan. Changing the portfolios used to plan the 33% RPS goals at this point will cause the CAISO to revisit already approved transmission solutions designed to meet the 33% RPS goal. This would in turn cause serious industry uncertainty regarding the state of already approved transmission solutions.

transmission capacity exists to interconnect additional renewable projects without major new transmission expansion. Nevertheless, a new RPS portfolio – even one that models a 33% RPS target – could still lead to a CAISO finding that new transmission capacity is necessary if such portfolio is sufficiently different than the 33% RPS portfolios previously studied.

How this scenario will be created: This scenario uses the same RPS portfolio that was supplied by Commission staff to the CAISO for the 2016-17 TPP, the "33% 2025 Mid AAEE" trajectory portfolio.[68] It is expected that the CAISO will supplement the Reliability Scenario with information regarding contracted RPS projects that have begun construction since the May 2016 LTPP A&S document was published. As a result, the renewable GWh energy value contained in the Reliability Scenario will exceed 33% of forecast demand.

(END OF ATTACHMENT)

[68] See section "4.2.7 RPS Portfolios for the 2015-16 TPP" of "Attachment 2" (found here: PDF) from the "Assigned Commissioner's Ruling on updates to the Planning Assumptions and Scenarios for use in the 2014 Long-Term Procurement Plan and the California Independent System Operator's 2015-2016 Transmission Planning Process" (found here: PDF).

Attachment 3a

EV Geographic Forecast Executive Summary

NAVIGANT RESEARCH

RESEARCH REPORT

Executive Summary:

Electric Vehicle Geographic Forecasts

Battery and Plug-In Hybrid Electric Vehicle Sales and Populations in North America

NOTE: This document is a free excerpt of a larger report. If you are interested in purchasing the full report, please contact Navigant Research at research-sales@navigant.com.

Published 2Q 2016

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Section 1
EXECUTIVE SUMMARY

1.1 Background Data

This report draws on the model results in Navigant Research's *Electric Vehicle Market Forecast* report published in 2015, with a specific focus on North America. The *Electric Vehicle Geographic Forecast* report assesses plug-in electric vehicle (PEV) sales and populations in the United States and Canada, and it provides detailed geographic breakdowns of PEV sales by U.S. state, core based statistical area (CBSA), Canadian province, and Canadian census metropolitan area (CMA). Forecasts provided in this report are done so under three scenario conditions: conservative, base, and aggressive. Results from Navigant Research's annual *Electric Vehicle Consumer Survey* are also included.

Navigant Research uses a number of variables to evaluate PEV demand by region. Sales forecasts per technology segment analyzed are determined by estimating the market share of the technology against all competing platforms as a function of a number of variables that feed into the consumer choice. At a high level, these variables are as follows: costs (net outlay, energy, and maintenance), capability (range, power, etc.), infrastructure, social/political concerns (environmental and geopolitical), and automotive industry support.

Various vehicle (commercial and consumer) and geographic markets will value the above variables differently, and each factor is weighed differently based on how the market is likely to value each variable relative to all others. This report disaggregates the national-level PEV forecasts produced through this method into more granular geographic components at the state, province, U.S. CBSA, and Canadian CMA level.

The disaggregation of national-level results is executed through a thorough examination of U.S. and Canadian demographic characteristic variations, regional consumer sentiments regarding vehicle purchases, state and regional transportation policies, population change and density, and other localized vehicle market conditions like retail fuel prices.

1.2 Market Forecasts

Growth in the North American PEV market slowed in 2015 as plug-in hybrid electric vehicle (PHEV) sales in the United States declined from 2014 highs. The decline in PHEV sales appears to be largely the result of vehicle availability, with the first generation Chevrolet Volt and Prius PHV witnessing production declines in preparation for the second generation versions.

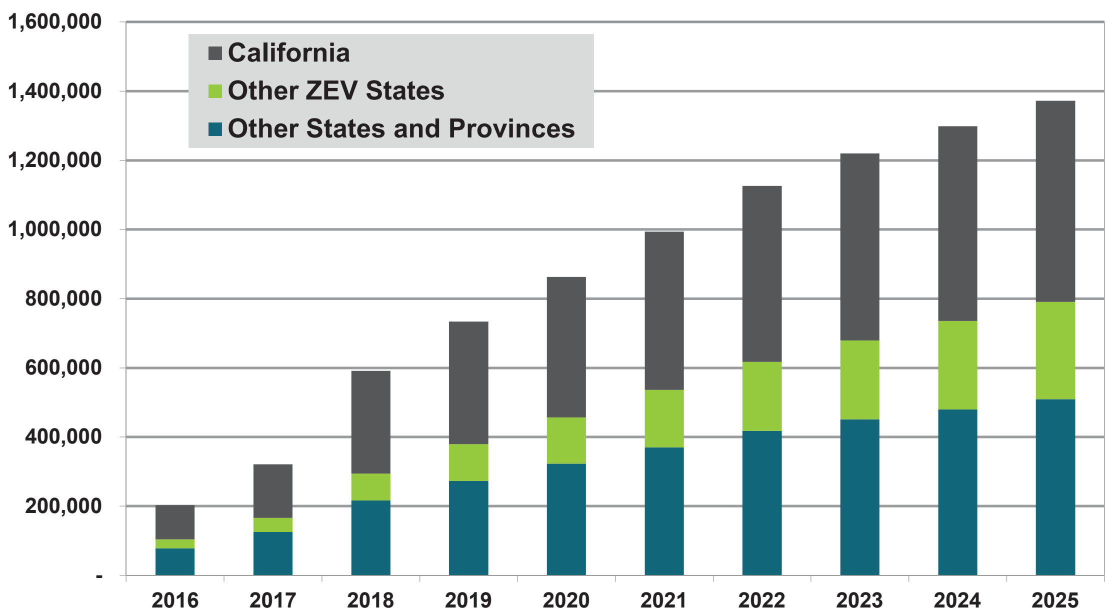
In 2016, Navigant Research expects the North American market to grow around 62% from 2015 levels, nearing 200,000 sales. Growth is anticipated to come from expanding sales of the Tesla Model X and the second-generation Volt, as well as the introduction of the Chevrolet Bolt 200-mile range battery electric vehicle (BEV), the Prius Prime PHEV, the

Chrysler Pacifica PHEV, and the Mitsubishi Outlander PHEV later in the year. Further ahead, Navigant Research estimates that the introduction of the Tesla Model 3 in late 2017 will likely boost the market by about 60% in 2017 and then nearly double the market in 2018 as the first full year of Model 3 sales is achieved. After 2018, strong but stable growth is expected with a compound annual growth rate from 2018 to 2025 in the base scenario of nearly 13%.

The PEV market in North America has been concentrated in the U.S. West Coast states, with PEV market share in California expected to be over 5% in 2016. Outside of the West Coast, a group of eight states in the Northeast is likely to see PEV sales increase considerably as automakers stress BEV deployments and marketing efforts in these states specifically to comply with the region's mandates for PEV production.

Outside of the zero emissions vehicle (ZEV) states, PEV sales are expected to grow most quickly in states with desirable PEV incentives, low vehicle capability and range requirements, and positive demographic characteristics toward PEVs. Hawaii and Washington are likely to maintain the significant market growth both states witnessed over the last 5 years. The deployment of BEVs with over 200 miles of range, expansion of PEVs outside of passenger car body type segments, and encouraging state purchase incentives are also likely to make Utah and Colorado leading PEV adopters.

Chart 1.1 PEV Sales by Major Market, Base Scenario, North America: 2016-2025



(Source: Navigant Research)

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SCOPE OF STUDY

This Navigant Research report provides a detailed breakdown of U.S. and Canadian PEV sales by geographic region, including state, province, U.S. CBSA, and Canadian CMA. This report has been expanded to include selected results of Navigant Research's annual *Electric Vehicle Consumer Survey*. The results consist of a comprehensive set of sales forecasts developed from both quantitative and qualitative research. They also offer a breakdown of the North American light duty vehicle market described in other Navigant Research reports, including the annual *Electric Vehicle Market Forecasts* report. The forecasts are provided in three scenarios: conservative, base, and aggressive.

This report's objective is to provide a more detailed examination of the market opportunity for PEVs within smaller geographic areas. This data can be used for vehicle production planning and determining future electric load requirements, charging station requirements, and other analytical needs. The report is meant to supply data needed for making decisions and identifying trends at a regional, state, provincial, or metropolitan levels. While some analysis on market development are provided, this report does not provide comprehensive analysis of trends for the overall global industry.

SOURCES AND METHODOLOGY

Navigant Research's industry analysts utilize a variety of research sources in preparing Research Reports. The key component of Navigant Research's analysis is primary research gained from phone and in-person interviews with industry leaders including executives, engineers, and marketing professionals. Analysts are diligent in ensuring that they speak with representatives from every part of the value chain, including but not limited to technology companies, utilities and other service providers, industry associations, government agencies, and the investment community.

Additional analysis includes secondary research conducted by Navigant Research's analysts and its staff of research assistants. Where applicable, all secondary research sources are appropriately cited within this report.

These primary and secondary research sources, combined with the analyst's industry expertise, are synthesized into the qualitative and quantitative analysis presented in Navigant Research's reports. Great care is taken in making sure that all analysis is well-supported by facts, but where the facts are unknown and assumptions must be made, analysts document their assumptions and are prepared to explain their methodology, both within the body of a report and in direct conversations with clients.

Navigant Research is a market research group whose goal is to present an objective, unbiased view of market opportunities within its coverage areas. Navigant Research is not beholden to any special interests and is thus able to offer clear, actionable advice to help clients succeed in the industry, unfettered by technology hype, political agendas, or emotional factors that are inherent in cleantech markets.

NOTES

CAGR refers to compound average annual growth rate, using the formula:

CAGR = (End Year Value ÷ Start Year Value)$^{(1/steps)}$ – 1.

CAGRs presented in the tables are for the entire timeframe in the title. Where data for fewer years are given, the CAGR is for the range presented. Where relevant, CAGRs for shorter timeframes may be given as well.

Figures are based on the best estimates available at the time of calculation. Annual revenues, shipments, and sales are based on end-of-year figures unless otherwise noted. All values are expressed in year 2016 U.S. dollars unless otherwise noted. Percentages may not add up to 100 due to rounding.

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Note: Editing of this report was closed on June 13, 2016.

Attachment 3b

EV Geographic Forecast Methodology

NAVIGANT RESEARCH

RESEARCH REPORT

Electric Vehicle Geographic Forecast Report Methodology

Battery and Plug-In Hybrid Electric Vehicle Sales and Populations in North America

Published 2Q 2016

Scott Shepard

Senior Research Analyst

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Senior Research Analyst

METHODOLOGY

1.1 Overview

The data provided in the 2016 Navigant Research Electric Vehicle Geographic report is a product of a national-level sales forecast model for global light vehicle markets, disaggregated at the state and county level. The national forecast model uses high-level macroeconomic factors like gross domestic product and population as well as vehicle density and historic sales data to project overall light vehicle market growth. Sales forecasts per technology segment analyzed are determined by estimating the market share of the technology against competing platforms as a function of a variables that feed into the consumer choice. At a high level, these variables are as follows:

- **Technology costs:** The purchase price of the technology relative to conventional vehicles. This variable is affected by fuel efficiency regulations, purchase subsidies, and economies of scale.
- **Energy costs:** The per-mile costs of powering the technology. This variable is affected by fuel efficiency regulations and the price of various alternative fuels.
- **Vehicle capability:** The ability of the technology to satisfy all consumer requirements; this is most tangibly conveyed through driving range, power, and hauling capacity.
- **Accessible infrastructure:** The availability of refueling/recharging infrastructure relative to conventional vehicles.
- **Geopolitical concerns:** The capacity of the technology to reduce oil consumption.
- **Environmental concerns:** The capacity of the technology to reduce carbon emissions and/or other regulated criteria air pollutants.
- **Maintenance:** The estimated required costs of vehicle upkeep relative to conventional vehicles.
- **Automaker support:** The vehicle production roadmap of automakers and anticipated capacities for production by year relative to the conventional vehicle.

Markets will value the above variables differently, and each factor is therefore weighed differently based on how the market is likely to value each variable relative to all others. Using the variables listed above, a score relative to the others is created per each technology, evaluated against past market performance and then used to calculate how changes to any or all of the above variables going forward will affect market share.

The results from the national sales model for plug-in electric vehicles and battery electric vehicles are then fed into a model that disaggregates the results by state based on state and local purchase incentives, mandates, retail fuel prices, demographics, and historic sales data. State level results are then disaggregated by county based on consumer demographics, the estimated county vehicle market size, sales history, and data derived from Navigant Research's Electric Vehicle Consumer Survey.

County-level sales are then aggregated by US Census bureau defined core based statistical areas to produce the forecasts of the Electric Vehicle Geographic Forecast report. The PEV population forecasts of the report are calculated based on vehicle sales, registration history, and estimated vehicle life. The method makes no assumptions regarding vehicle registration travel within or out of states. All registration occurring within a territory are assumed to remain in that territory until the vehicle is removed from use.

SOURCES AND METHODOLOGY

Navigant Research's industry analysts utilize a variety of research sources in preparing Research Reports. The key component of Navigant Research's analysis is primary research gained from phone and in-person interviews with industry leaders including executives, engineers, and marketing professionals. Analysts are diligent in ensuring that they speak with representatives from every part of the value chain, including but not limited to technology companies, utilities and other service providers, industry associations, government agencies, and the investment community.

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Attachment 4

2015 and Beyond Potential and

Goals Study Stage 1 Final Report 92515

NAVIGANT

Energy Efficiency Potential and Goals Study for 2015 and Beyond

Stage 1 Final Report

Prepared for:
California Public Utilities Commission

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Reference No.: 174655
September 25, 2015

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Special thanks are due to the staff of California Public Utilities Commission and the many stakeholders for providing direction, guidance, insight, and data throughout the conduct of this study.

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Executive Summary

Introduction

Navigant Consulting, Inc. along with its partners Tierra Resources Consultants LLC, DNV GL, ASWB Engineering, RedHorse Corp, and Opinion Dynamics (collectively known as "the Navigant team") developed this study ("2015 and Beyond Potential and Goals Study") to analyze energy and demand savings potential in the service territories of four of California's investor-owned utilities (IOUs) during the post 2015 energy efficiency (EE) portfolio planning cycle. This report includes results for Pacific Gas and Electric (PG&E), Southern California Edison (SCE), San Diego Gas and Electric (SDG&E), and Southern California Gas (SCG). A key component of the 2015 Potential and Goals Study (2015 Study) is the Potential and Goals Model (PG Model), which provides a single platform in which to conduct robust quantitative scenario analysis that reflects the complex interactions among various inputs and Policy Drivers.

The 2015 Study is the third consecutive potential study conducted by the Navigant team on behalf of the California Public Utilities Commission (CPUC). Navigant conducted the 2011[1] study which informed the 2013-14 IOU program goals and the 2013 Study[2] which was used to inform the 2015 goals for California IOUs. The model developed in the 2013 Study serves as the methodological basis for this study. As such, the 2015 study is considered an "update study" relative to the 2013 Study.

The 2015 Potential and Goals Study supports four related efforts:

1. Inform the CPUC as it proceeds to adopt goals and targets, providing guidance for the next IOU energy efficiency portfolios. The potential model is a framework that facilitates the stakeholder process. The model helps build consensus for goals by soliciting agreement on inputs, methods, and model results.
2. Guide the IOUs in portfolio planning and the state' principal energy agencies in forecasting for procurement, including the planning efforts of the CPUC, California Energy Commission (CEC), and California Independent System Operator (CAISO). Although the model cannot be the sole source of data for IOU program planning activities, it can provide critical guidance for the IOUs as they develop their plans for the 2016 and beyond portfolio planning period. The study is also providing California's principal energy agencies with the tools and resources necessary to develop outputs in a manner that is most appropriate for their planning and procurement needs.
3. Inform strategic contributions to greenhouse gas reduction targets. As the rules and impacts of Assembly Bill (AB) 32 are gaining traction, the model must account for Greenhouse Gas (GHG) savings estimates. This will provide an opportunity to understand how extensively IOU programs and energy efficiency can help meet AB32 goals. Navigant will work with the CPUC and stakeholders to develop stretch GHG reduction scenarios.

---

[1] Navigant. *Analysis to Update Energy Efficiency Potential, Goals, and Targets for 2013 and Beyond - Track 1.* May 2012.

[2] Navigant. *2013 California Energy Efficiency Potential and Goals Study*. February 2014.

4. Develop metrics for the CPUC's Energy Efficiency Strategic Plan update.[3] The Plan identifies a number of strategies that move beyond current approaches for energy efficiency resource deployment and lays the groundwork for their implementation. The 2015 Study is expected to inform, as well as be informed by the Plan, by helping to provide metrics, including projections of additional energy savings estimates, for the 2015 Strategic Plan Update Goals. This may include aligning the potential model with strategic plan initiatives, identifying appropriate metrics, characterizing the baseline, developing scenarios, and creating a tracking mechanism.

CPUC policy making informed and directed this study, as outlined in Rulemaking (R.) 09-11-014 and most recently by Decision (D.) 12-05-015, which provided guidance on the 2013-2014 energy efficiency portfolios. D.14-10-046 (Phase I of R.13-11-005) adopted energy efficiency savings goals for 2015 and Phase II of the proceeding will adopt goals for a three year period starting in 2016.[4] The study period spans from 2016-2024 based on the direction provided by CPUC and focuses on current and potential drivers of energy savings in IOU service areas. Analysis of energy efficiency savings in publicly owned utility service territories is not part of the scope of this effort.

The Navigant team and the CPUC have conducted outreach to stakeholders in the development of this model. The comments and questions raised during these meetings have informed the development of the PG Model and the study.

Scope of this Study

The four primary uses of the 2015 and Beyond Potential Study correspond to the four distinct tasks that will be used throughout the project:

- **Task 1 Potential and Goals Study Update.** This task will inform the CPUC as it proceeds to adopt goals for future IOU energy efficiency portfolios.
- **Task 2: Additional Achievable Energy Efficiency (AAEE) Savings Forecast.** This task will develop savings forecasts for use by CPUC, CEC, and CAISO in long term planning exercises.
- **Task 3: Energy Efficiency Targets for Greenhouse Gas Reductions.** This task will quantify how extensively IOU programs and energy efficiency can help meet AB32 goals.
- **Task 4: Metrics to Support the Strategic Plan Update.** This task will help provide metrics, including projections of additional energy savings estimates, for the 2015 Strategic Plan Update Goals.

This report represents the first of multiple updates to the potential study that will occur through 2018. This report focuses on Task 1: Potential and Goals Study Update. Specifically, this report represents the first stage of Task 1 updates (Stage 1). The CPUC and Navigant worked together to determine the appropriate scope of Stage 1 updates given the regulatory timeline for setting 2016 and beyond goals. Stage 1 of Task 1 is primarily a data update to the PG model to inform 2016 and beyond goals; it is the sole topic of this report. The scope of Stage 1 was to:

---

[3] More information on the Plan can be found at: http://www.cpuc.ca.gov/PUC/energy/Energy+Efficiency/eesp/

[4] Note that the 2016-2018 period is tentative and will ultimately be determined in Phase II of R.13-11-005.

» Maintain the 2013 PG Model methodology, infrastructure, architecture, and types of output (the 2013 PG model methodology is documented in detail in the 2013 Study report[5]);

» Correct minor issues where the 2013 PG model methodology is not aligned with current CPUC policy; and

» Rely on new secondary data sources to update the PG model with the latest available information to better inform the 2016 and beyond goal setting process.

The majority of the effort undertaken by the team on Stage 1 was to review and incorporate the latest available data into the study. The CPUC provided the following high level direction to Navigant throughout the data update process:

» Database for Energy Efficient Resources (DEER) data must be incorporated for high impact measures including DEER2014 Update and DEER2015 Update.[6]

» 2010-12 Evaluation, Measurement, and Verification (EM&V) impact studies should further update DEER data for residential and commercial measures.

» 2010-12 EM&V evaluations should be used to inform updates to Codes and Standards (C&S) analysis, behavior program analysis, and financing analysis.

» The latest California appliance saturation survey studies should be relied upon for key market data.

» In regards to IOU workpapers, the Navigant team should only rely upon those reports that went through a rigorous CPUC review process (however, un-reviewed workpapers could be used to characterize emerging technologies).

» In regards to Industry Standard Practice (ISP) studies, the Navigant team should only rely upon those that are CPUC vetted and approved.

Given the short timeline of Stage 1, the various data update tasks were prioritized by the team along with CPUC input. Table ES-1 lists the Stage 1 key data update activities along with their assigned priority. The priority indicates the relative level of effort allocated to each update activity; high priority items obtained more attention and resources than low priority items.

[5] Navigant. *2013 California Energy Efficiency Potential and Goals Study*. February 2014. The report is available at http://www.cpuc.ca.gov/PUC/energy/Energy+Efficiency/Energy+Efficiency+Goals+and+Potential+Studies.htm.

[6] The full DEER2016 cannot be incorporated into Stage 1 due to the timeline of the DEER2016 release relative to the timeline of Stage 1. However, the Navigant team did coordinate with the DEER team to best align the study to any new DEER changes and made some high priority adjustments to the potential study in responses based on a draft of DEER2016.

Table ES-1: Stage 1 Data Update Priorities

Key Data Update Activity.	Stage 1 Priority
Update Residential and Commercial measures with the following data sources: DEER, 10-12 EM&V studies, the Measure Cost Study, and saturation studies.	High
Update C&S savings analysis using the 2010-12 impact evaluation study, update methodology to match CPUC policy.	High
Update Agricultural, Industrial, Mining, and Street-Lighting to incorporate the latest Industry Standard Practice studies.	High
Incorporate the latest non-measure inputs regarding retail rates, building stocks, avoided costs, and utility program costs.	High
Update Whole Building Energy Efficiency data using 2010-12 EM&V data, DEER data, CEC building code data, and other available studies.	Medium
Update Emerging Technologies data assumptions, specifically review LED assumptions with regards to the California Lighting Quality Standards.	Medium
Provide the ability to view measure level results from the model.	Medium
Update Behavior and Conservation analysis with latest EM&V and utility data and coordinate with the ongoing CPUC behavior studies.	Low
Update Financing analysis with latest EM&V data and coordinate with the ongoing CPUC financing studies.	Low

Source: Navigant team discussions with CPUC Staff

Sources of Potential

Consistent with the 2013 Study, the 2015 Study examines the potential from the following:

» Residential and Commercial rebated measures

» Agriculture, Industrial, and Mining rebated measures

» Street Lighting measures

» Residential and Commercial behavior programs (home energy reports and building operator certification/training)

» Codes and Standards

» "Emerging Technologies" for the Residential, Commercial, and Street Lighting sectors

» Whole building initiatives (existing building renovation and new construction for the Residential and Commercial sector)

» Low Income programs

» Incremental savings due to energy efficiency financing

Consistent with the 2013 Study, the 2015 Study forecasts energy efficiency potential at three levels for rebate programs:

1. **Technical Potential**: Technical potential is defined as the amount of energy savings that would be possible if the highest level of efficiency for all technically applicable opportunities to improve energy efficiency were taken, including retrofit measures, replace-on-burnout measures, and new construction measures. Technical potential represents the immediate replacement of applicable equipment-based technologies regardless of the remaining useful life of the existing measure. Consistent with industry best practices, technical potential does not and is not meant to account for equipment stock turnover.
2. **Economic Potential**: Using the results of the technical potential analysis, the economic potential is calculated as the total energy efficiency potential available when limited to only cost effective measures.[7] All components of economic potential are a subset of technical potential. Similar to technical potential, economic potential does not account for equipment stock turnover.
3. **Market Potential**: The final output of the potential study is a market potential analysis, which calculates the energy efficiency savings that could be expected in response to specific levels of incentives and assumptions about policies, market influences, and barriers. All components of market potential are a subset of economic potential. Some studies also refer to this as "achievable potential." Market potential is used to inform the utilities' energy efficiency goals, as determined by the CPUC.

The market potential reported in this study is the incremental market potential. The incremental potential represents the annual energy and demand savings achieved by the set of programs and measures in the first year that the measure is implemented. It does not consider the additional savings that the measure will produce over the life of the equipment. A view of incremental savings is necessary in order to understand what additional savings an individual year of energy efficiency programs will produce. This has historically been the basis for IOU program goals.

A large number of variables drive the calculation of market potential. These include assumptions about the manner in which efficient products and services are marketed and delivered, the level of customer awareness of energy efficiency, and customer willingness to install efficient equipment or operate equipment in ways that are more efficient. The Navigant team used the best available current market knowledge and followed these guidelines in developing the recommended market potential:

1. Provide a view of market potential where data sources and calculation methods are transparent and clearly documented.
2. Avoid assumptions and model design decision that would establish goals and targets that are aspirational, but for which the technologies or market mechanisms to attain these goals may not yet be clearly defined.

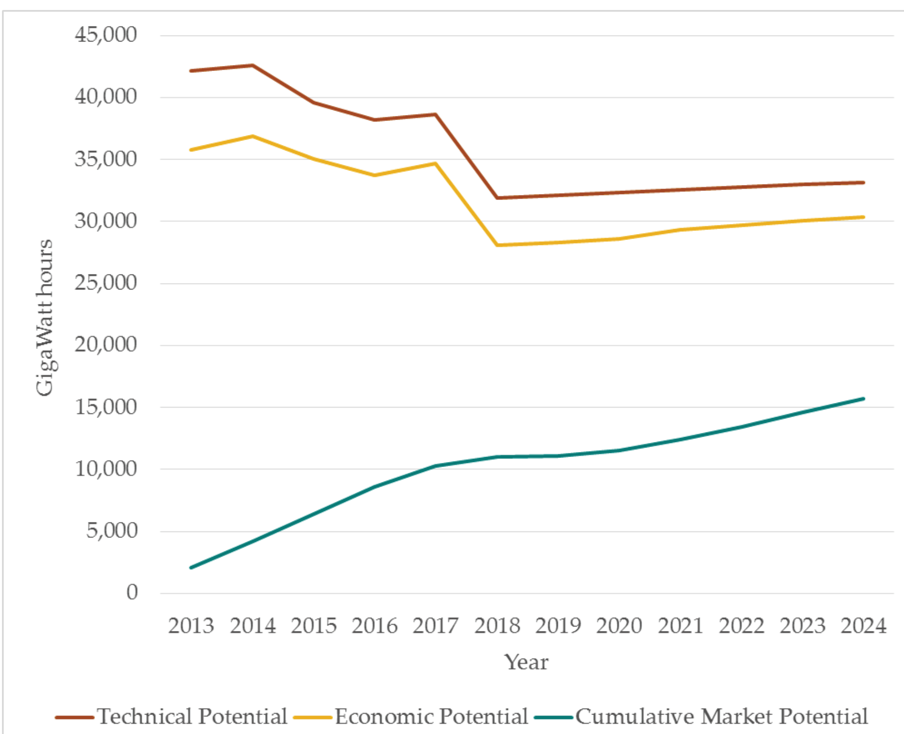
[7] The default assumption for this study includes all non-emerging technologies with a total resource cost (TRC) test of 0.85 or greater; emerging technologies are included if they meet a TRC of 0.5 in a given year and also achieve the TRC for non-emerging technologies (0.85) within ten years of market introduction. The model includes savings from measure bundles commonly adopted for low income programs; low income programs generally have a TRC less than 0.85 and are not required to be cost effective. These measure bundles are thus included for the purposes of calculating economic potential.

With these precepts in mind, the Navigant team considers that the market potential presented in this study is a viable basis for energy efficiency forecasting to which load forecasters, system planners, and resource procurement specialists could agree. However, this study may not capture the upper bound on the total amount of energy efficiency that can be achieved. There may be additional energy savings to capture, particularly from systems efficiency and behavior change, which could not be reliably quantified based on past EM&V results available at the time of this study.

Results

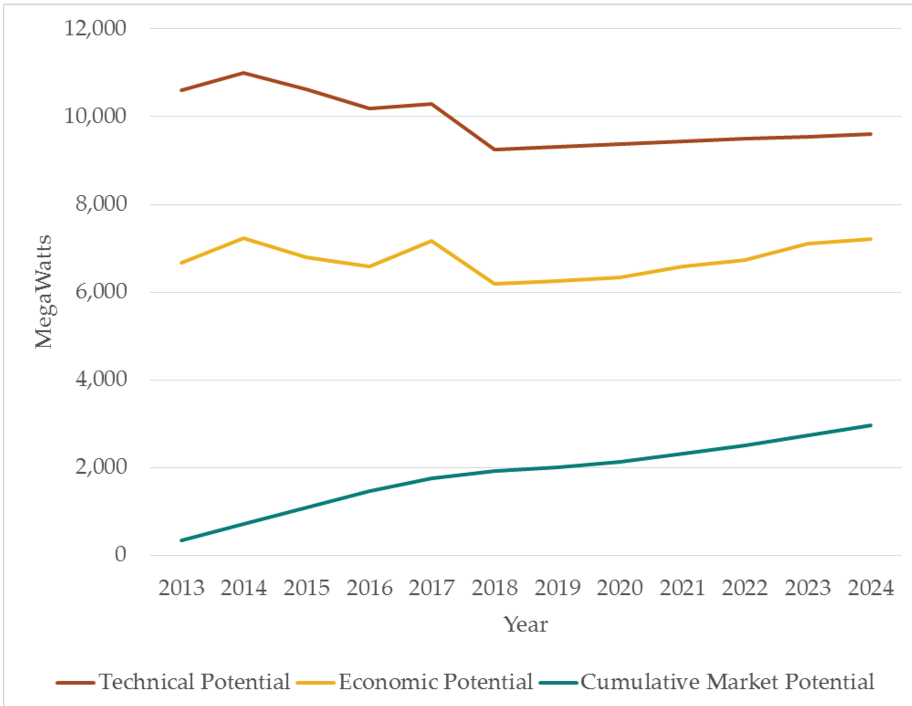
Figure ES-1 and Figure ES-2 illustrate the statewide technical, economic and cumulative market potential for electricity and natural gas respectively. Figure ES-1 shows a technical potential of approximately 38,000 GWh in 2016 and an economic potential of approximately 33,700 GWh. Cumulative market potential grows at a relatively constant rate from 2013 to 2017 when its trajectory slows. This change in trajectory is due to the effects of new lighting C&S that come into effect in 2018 and decrease the IOU claimable savings. Technical and economic potential also decrease in 2018 due to changes in lighting C&S. Figure ES-2 shows a technical potential of approximately 2,000 MMTherms in 2016 and an economic potential of approximately 1,800 MMTherms. Cumulative market potential grows at a relatively constant rate throughout the study period. Section 4.1 of this report contain additional discussion of the technical, economic, and cumulative market potential and also illustrates savings as a percent of energy sales.

Figure ES-1: Statewide Technical, Economic and Cumulative Electric Potential



Source: June 2015 PG Model

Figure ES-2: Statewide Technical, Economic and Cumulative Natural Gas Potential



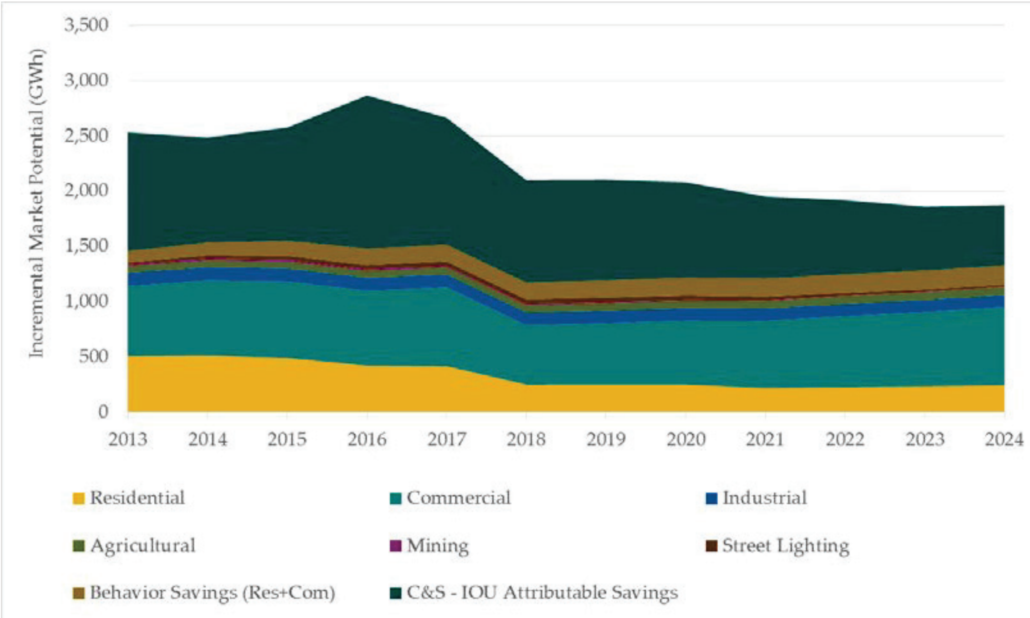
Source: June 2015 PG Model

Figure ES-3 through Figure ES-5 illustrate the statewide incremental market potential from IOU programs for electric (GWh), peak demand (MW) and gas (MMTherms) respectively. These graphs include IOU claimable savings from C&S advocacy programs and behavior programs but they do not include the effects of energy efficiency financing.

Figure ES-3 shows a large portion of IOU potential comes from IOU attributable C&S savings. Residential and Commercial rebated equipment has historically contributed a significant amount of savings to IOU programs and will continue to do so through 2017. In 2018, changes in lighting C&S act to reduce IOU claimable savings. The AIMS sectors remain a small portion of future potential. IOU behavior programs provide more electric savings than the agriculture, mining and streetlighting sectors combined.

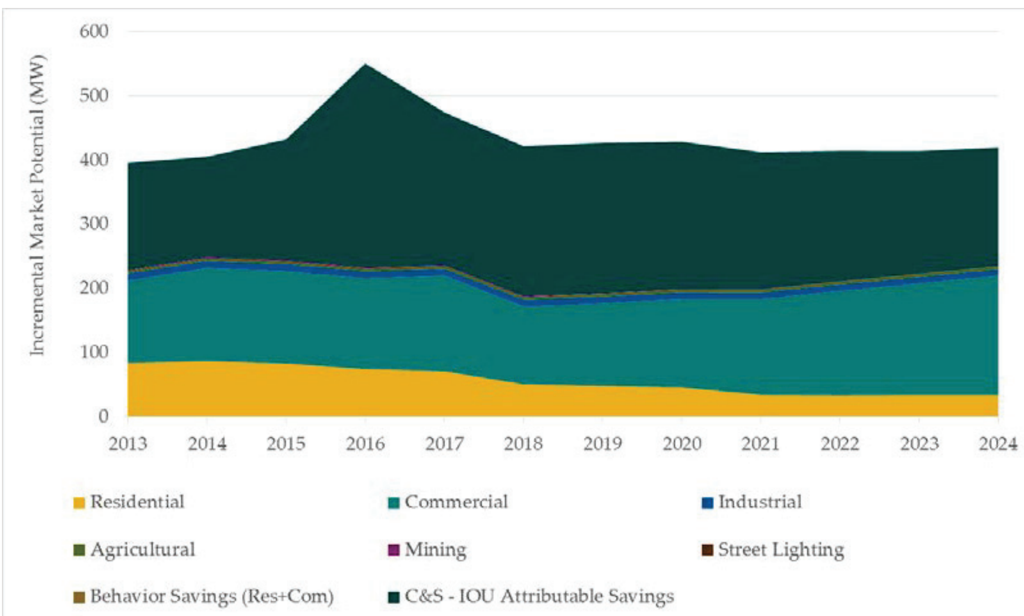
Figure ES-4 shows similar trends for peak demand savings with a few noted differences: behavior programs and street lighting measures do not have any quantified IOU claimable savings potential. Figure ES-4 also shows a spike in expected demand savings in 2016 from C&S. This spike is due to expected 2016 Title 20 HVAC standards regarding air filter labeling.

Figure ES-3: Statewide Incremental Electric Potential



Source: June 2015 PG Model

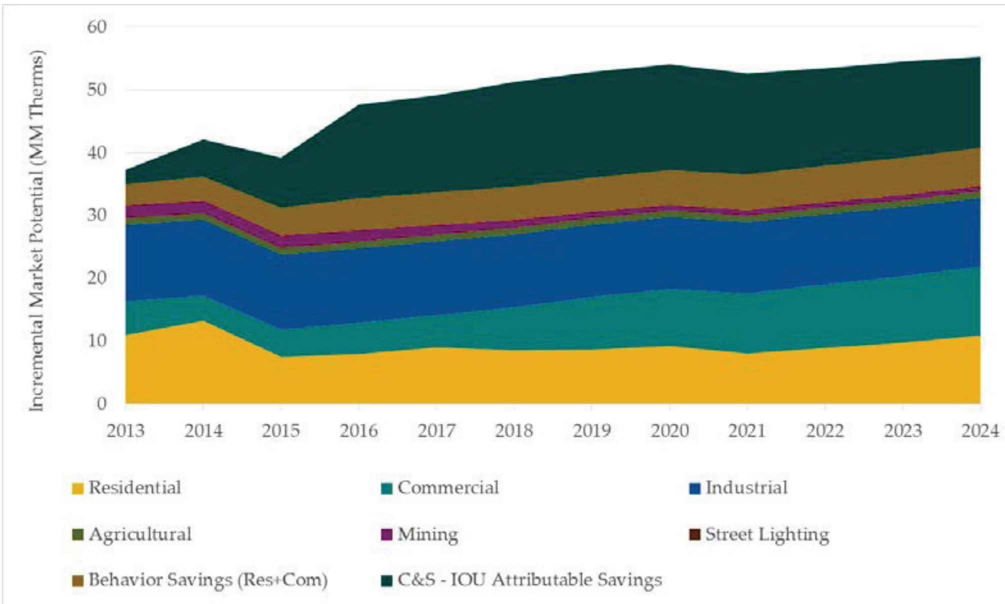
Figure ES-4: Statewide Incremental Demand Potential



Source: June 2015 PG Model

Figure ES-5 shows larger contributions by the Industrial and Mining sectors towards total gas savings potential. Residential and Commercial savings are expected to grow in 2016 and beyond. C&S savings will continue to play a role in IOU program potential but is not as significant of a contributor when compared to electric savings. Like electric potential, IOU behavior programs provide more gas savings than the agriculture, mining and streetlighting sectors combined.

Figure ES-5: Statewide Incremental Natural Gas Potential



Source: June 2015 PG Model

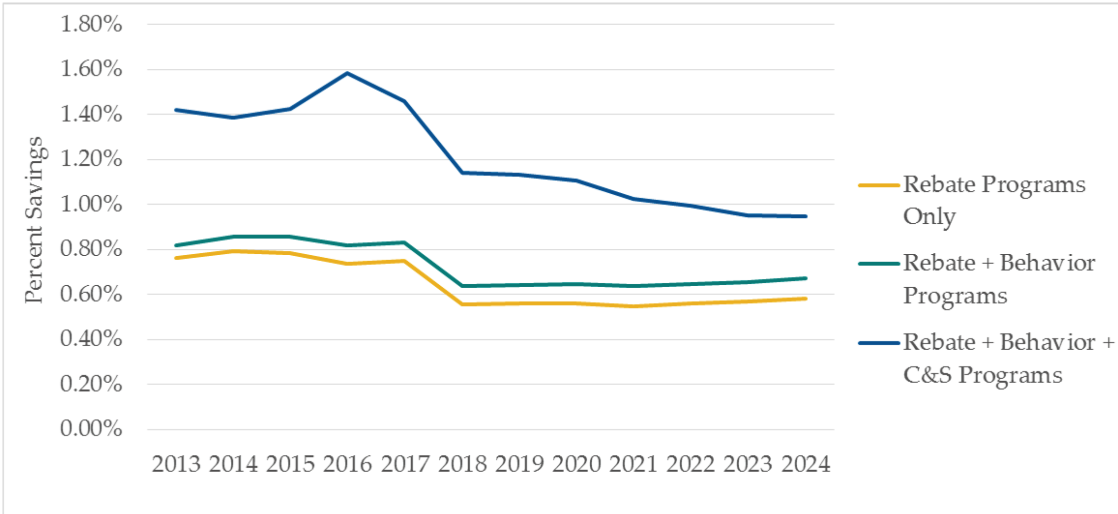
The proposed Assembly Bill 1330 would create an Energy Efficiency Resource Standard (EERS) in California; a statewide target for electric and natural gas efficiency savings. AB 1330, as currently written, would set the following targets:

» Incremental electric savings achieved of no less than 1.5% in 2020 and 2% in 2025

» Incremental natural gas savings achieved of no less than 0.75% in 2020 and 1% in 2025

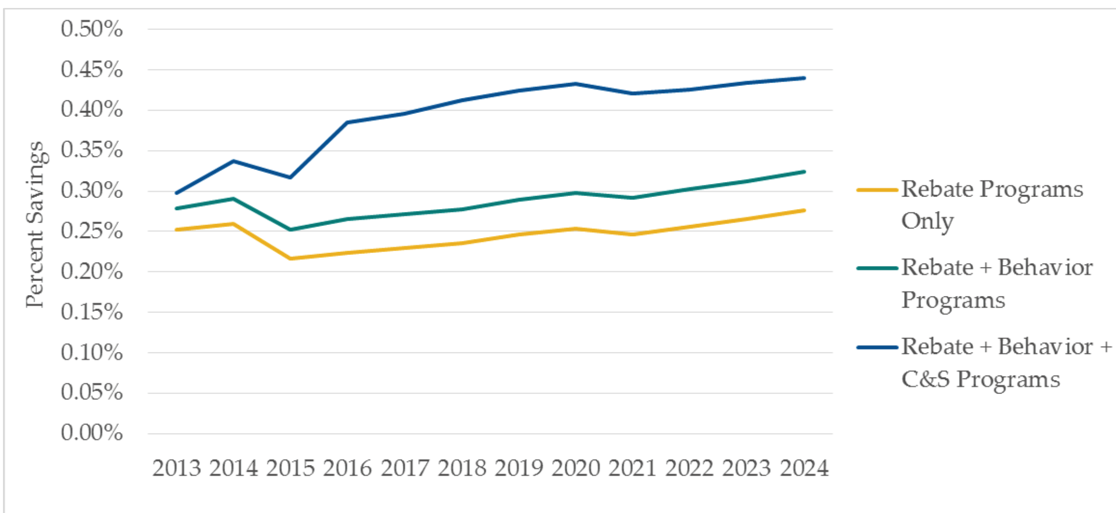
Figure ES-6 illustrates the percent savings in each year considering three sources of savings (rebate programs, behavior programs and IOU C&S programs). It is unclear at this time which sources of savings can and should be counted towards AB 1330 targets. When considering only IOU rebate programs, savings in 2016 amounts to 0.74% of sales. Adding the savings from behavior programs increases the value to 0.82%. The total savings from rebate programs, behavior programs and C&S in 2016 results in 1.58% savings. Savings as a percent of retail sales declines over time. A similar graph for gas savings can be found in Figure ES-7. In all analyzed situations, gas savings is less than 0.5% of CEC forecasted gas sales.

Figure ES-6: Statewide IOU Electric Savings as a Percent of Annual Sales



Source: June 2015 PG Results Viewer

Figure ES-7: Statewide IOU Natural Gas Savings as a Percent of Annual Sales



Source: June 2015 PG Results Viewer

The following tables detail the annual incremental market potential for each IOU from 2016 through 2024. The potential is disaggregated by rebate programs (including behavior programs) as well as net C&S (IOU claimable) savings. Savings values for PG&E and SDG&E include interactive effects (the impact of electric energy efficiency on gas savings) while savings for SCE and SCG exclude these interactive effects. IOU rebate program potential shown in the tables below are gross incremental annual savings while the IOU claimable C&S savings are net IOU attributable annual savings. Savings values for SDG&E further reflect an adjustment to whole building savings to be consistent with CPUC Decision 14-10-046 (further discussion can be found in section 1.4)

Table ES-2: PG&E Market Potential

	GWh			MW			MMTherms		
Year	Rebate Programs*	Net C&S	Total	Rebate Programs*	Net C&S	Total	Rebate Programs*	Net C&S	Total
2016	624.5	611.3	1,235.9	85.0	140.6	225.6	12.9	5.5	18.4
2017	637.4	506.5	1,143.9	87.4	105.2	192.6	12.9	5.7	18.6
2018	507.4	408.3	915.7	68.9	103.2	172.1	14.8	6.1	20.9
2019	510.9	401.0	911.9	69.6	103.3	173.0	14.9	6.2	21.1
2020	519.1	380.9	900.0	71.4	101.3	172.7	15.5	6.2	21.7
2021	523.9	326.2	850.1	74.4	94.3	168.8	15.9	5.9	21.8
2022	541.2	294.7	835.9	80.3	89.7	170.0	16.7	5.7	22.4
2023	558.2	254.1	812.3	86.3	84.4	170.7	17.5	5.6	23.2
2024	581.3	239.8	821.1	91.7	81.5	173.3	18.6	5.3	23.9

**Includes behavior programs, excludes effects of financing.*
Source: June 2015 PG Model

Table ES-3: SCE Market Potential

	GWh			MW			MMTherms		
Year	Rebate Programs*	Net C&S	Total	Rebate Programs*	Net C&S	Total	Rebate Programs*	Net C&S	Total
2016	673.8	630.5	1,304.4	122.3	145.0	267.3	0.0	0.0	0.0
2017	693.5	522.4	1,215.9	123.0	108.5	231.4	0.0	0.0	0.0
2018	527.7	421.1	948.8	99.4	106.4	205.8	0.0	0.0	0.0
2019	541.8	413.6	955.3	103.1	106.6	209.7	0.0	0.0	0.0
2020	553.0	392.9	945.9	106.9	104.5	211.4	0.0	0.0	0.0
2021	542.4	336.5	878.9	103.3	97.3	200.6	0.0	0.0	0.0
2022	558.8	304.0	862.7	108.6	92.5	201.1	0.0	0.0	0.0
2023	573.2	262.1	835.4	113.2	87.1	200.3	0.0	0.0	0.0
2024	592.8	247.3	840.2	118.8	84.1	202.9	0.0	0.0	0.0

**Includes behavior programs, excludes effects of financing.*
Source: June 2015 PG Model

Table ES-4: SCG Market Potential

	GWh			MW			MMTherms		
Year	Rebate Programs*	Net C&S	Total	Rebate Programs*	Net C&S	Total	Rebate Programs*	Net C&S**	Total
2016	0.0	0.0	0.0	0.0	0.0	0.0	17.3	11.7	29.1
2017	0.0	0.0	0.0	0.0	0.0	0.0	18.1	12.2	30.3
2018	0.0	0.0	0.0	0.0	0.0	0.0	16.6	12.7	29.4
2019	0.0	0.0	0.0	0.0	0.0	0.0	18.0	12.6	30.6
2020	0.0	0.0	0.0	0.0	0.0	0.0	18.4	12.2	30.6
2021	0.0	0.0	0.0	0.0	0.0	0.0	17.7	10.9	28.6
2022	0.0	0.0	0.0	0.0	0.0	0.0	18.2	10.3	28.5
2023	0.0	0.0	0.0	0.0	0.0	0.0	18.6	9.6	28.2
2024	0.0	0.0	0.0	0.0	0.0	0.0	19.0	9.1	28.1

**Includes behavior programs, excludes effects of financing.*
***Excludes interactive effects*
Source: June 2015 PG Model

Table ES-5: SDG&E Market Potential

	GWh			MW			MMTherms		
Year	Rebate Programs*	Net C&S	Total	Rebate Programs*	Net C&S	Total	Rebate Programs*	Net C&S	Total
2016	181.0	143.1	324.1	24.5	32.9	57.4	2.6	0.6	3.2
2017	185.0	118.6	303.5	25.7	24.6	50.3	2.7	0.6	3.3
2018	140.8	95.6	236.4	19.6	24.1	43.7	3.2	0.7	3.9
2019	143.7	93.8	237.6	20.1	24.2	44.2	3.2	0.7	3.9
2020	147.3	89.2	236.4	20.9	23.7	44.6	3.3	0.7	4.0
2021	146.6	76.4	223.0	21.1	22.1	43.2	3.0	0.7	3.7
2022	151.3	69.0	220.3	22.5	21.0	43.4	3.1	0.6	3.7
2023	154.4	59.5	213.9	23.4	19.8	43.2	3.2	0.6	3.8
2024	158.1	56.1	214.2	24.5	19.1	43.6	3.2	0.6	3.8

**Includes behavior programs, excludes effects of financing. Includes adjustment for whole building savings to be consistent with CPUC Decision 14-10-046*
Source: June 2015 PG Model

Significant data updates have been made in Stage 1 that cause results to depart from those previously stated in the 2013 Study. A comparison of statewide (all IOUs combined) savings found in Table ES-6 through Table ES-8.

Relative to the 2013 study, overall potential from electric rebate programs decreased slightly between 2016 and 2018 while potential from C&S increased during the same period. Thus total electric potential from 2016 to 2018 increased. Rebate program electric potential after 2018 (after major changes in lighting standards take effect) decrease relative to the 2013 study.

Relative to the 2013 study, overall potential from gas rebate programs decreased on the order of 20% from 2016 through 2024. However, during this same period potential from C&S increased significantly relative to the 2013 study. The net effect of both changes is an overall minimal change to the total potential over the 2016-2024 period though a 9% increase is observed in 2016 and 2017.

The key drivers behind the differences in the results of the two studies are listed below.

» The 2015 study uses more up-to date historic market data for the purposes of model calibration. The 2015 study uses evaluated program results from 2010-12 that was not available in the 2013 study as well as better data about the saturation of equipment from saturation surveys (CLASS and CSS).

» Residential and commercial measures assumptions about unit energy savings were sourced from the DEER2015 Update and 10-12 EM&V studies. Some additional adjustments to CFLs, refrigerator recycling, and commercial lighting were made based on DEER2016 and the Ex Ante Uncertain Measures update.

» The 2015 study used updated measure cost data to characterize residential and commercial measures. The 2013 study in some case relied upon cost data from as early as 2008. HVAC and appliance measures saw the largest changes in cost given this data refresh.

» The CEC proved updated building stock and energy consumption forecasts.

» The updated CPUC evaluation of IOU C&S programs (2010-12 EM&V study) shows more savings than previous evaluation results (2006-08 EM&V study)

» Additional data about IOU behavior programs has generally increased behavior program savings

» Better data on LEDs was obtained. LED assumptions are more conservative in both price and efficacy in the 2015 study relative to the 2013 study. This results in a lower LED potential in the 2015 compared to the 2013 study. In the 2013, much of the increase in potential after 2018 came from LEDs. The post-2018 LED potential is more conservative given data updates.

Table ES-6: 2015 Stage 1 vs. 2013 Study Results: Electric Potential (GWh)

	2013 Study			2015 Stage 1			Difference		
Year	Rebate Programs*	Net C&S	Total	Rebate Programs*	Net C&S	Total	Rebate Programs*	Net C&S	Total
2016	1,637	937	2,574	1,482	1,385	2,867	-9%	48%	11%
2017	1,600	734	2,334	1,517	1,147	2,665	-5%	56%	14%
2018	1,227	664	1,891	1,177	925	2,102	-4%	39%	11%
2019	1,335	644	1,979	1,196	908	2,105	-10%	41%	6%
2020	1,463	613	2,076	1,219	863	2,082	-17%	41%	0%
2021	1,589	517	2,106	1,213	739	1,952	-24%	43%	-7%
2022	1,720	458	2,178	1,251	668	1,919	-27%	46%	-12%
2023	1,829	366	2,195	1,286	576	1,862	-30%	57%	-15%
2024	1,932	337	2,269	1,332	543	1,875	-31%	61%	-17%

**Includes behavior programs, excludes effects of financing.*
Source: June 2015 PG Model, and 2013 Study

Table ES-7: 2015 Stage 1 vs. 2013 Study Results: Demand Potential (MW)

	2013 Study			2015 Stage 1			Difference		
Year	Rebate Programs*	Net C&S	Total	Rebate Programs*	Net C&S	Total	Rebate Programs*	Net C&S	Total
2016	266	192	458	232	319	551	-13%	66%	20%
2017	268	127	395	236	238	475	-12%	88%	20%
2018	218	123	341	188	234	422	-14%	90%	24%
2019	238	122	360	193	234	427	-19%	92%	19%
2020	262	119	381	199	230	429	-24%	93%	13%
2021	285	109	394	199	214	413	-30%	96%	5%
2022	311	103	414	211	203	415	-32%	97%	0%
2023	335	94	429	223	191	414	-33%	103%	-3%
2024	358	90	448	235	185	420	-34%	105%	-6%

**Includes behavior programs, excludes effects of financing.*
Source: June 2015 PG Model, and 2013 Study

Table ES-8: 2015 Stage 1 vs. 2013 Study Results: Natural Gas Potential (MMTherms)

	2013 Study			2015 Stage 1			Difference		
Year	Rebate Programs*	Net C&S	Total	Rebate Programs*	Net C&S	Total	Rebate Programs*	Net C&S	Total
2016	39.2	7.3	46.5	32.8	17.9	50.6	-16%	145%	9%
2017	39.0	9.1	48.1	33.7	18.5	52.2	-13%	103%	9%
2018	43.5	10.5	54.0	34.6	19.6	54.2	-20%	87%	0%
2019	45.1	11.2	56.3	36.1	19.5	55.6	-20%	74%	-1%
2020	47.1	11.3	58.4	37.3	19.1	56.3	-21%	69%	-4%
2021	48.9	10.2	59.1	36.6	17.5	54.1	-25%	71%	-9%
2022	50.8	10.0	60.8	38.0	16.6	54.6	-25%	66%	-10%
2023	52.4	9.9	62.3	39.3	15.9	55.2	-25%	61%	-11%
2024	54.1	9.7	63.8	40.8	15.0	55.9	-25%	55%	-12%

**Includes behavior programs, excludes effects of financing.*
Source: June 2015 PG Model, and 2013 Study

1. Introduction

1.1 Context of the Goals and Potential Study

Navigant Consulting, Inc. along with its partners Tierra Resources Consultants LLC, DNV GL, ASWB Engineering, RedHorse Corp, and Opinion Dynamics (collectively known as "the Navigant team") developed this study ("2015 and Beyond Potential and Goals Study") to analyze energy and demand savings potential in the service territories of four of California's investor-owned utilities (IOUs) during the post 2015 energy efficiency (EE) portfolio planning cycle. This report includes results for Pacific Gas and Electric (PG&E), Southern California Edison (SCE), San Diego Gas and Electric (SDG&E), and Southern California Gas (SCG). A key component of the 2015 Potential and Goals Study (2015 Study) is the Potential and Goals Model (PG Model), which provides a single platform in which to conduct robust quantitative scenario analysis that reflects the complex interactions among various inputs and Policy Drivers.

The 2015 Study is the third consecutive potential study conducted by the Navigant team on behalf of the California Public Utilities Commission (CPUC). Navigant conducted the 2011[8] study which informed the 2013-14 IOU program goals and the 2013 Study[9] which was used to inform the 2015 goals for California IOUs. The model developed in the 2013 Study serves as the methodological basis for this study. As such, the 2015 study is considered an "update study" relative to the 2013 Study.

The 2015 Potential and Goals Study supports four related efforts:

1. Inform the CPUC as it proceeds to adopt goals and targets, providing guidance for the next IOU energy efficiency portfolios. The potential model is a framework that facilitates the stakeholder process. The model helps build consensus for goals by soliciting agreement on inputs, methods, and model results.
2. Guide the IOUs in portfolio planning and the state' principal energy agencies in forecasting for procurement, including the planning efforts of the CPUC, California Energy Commission (CEC), and California Independent System Operator (CAISO). Although the model cannot be the sole source of data for IOU program planning activities, it can provide critical guidance for the IOUs as they develop their plans for the 2016 and beyond portfolio planning period. The study is also providing California's principal energy agencies with the tools and resources necessary to develop outputs in a manner that is most appropriate for their planning and procurement needs.
3. Inform strategic contributions to greenhouse gas reduction targets. As the rules and impacts of AB32 are gaining traction, the model must account for (greenhouse gas) GHG savings estimates. This will provide an opportunity to understand how extensively IOU programs and energy

[8] Navigant. *Analysis to Update Energy Efficiency Potential, Goals, and Targets for 2013 and Beyond - Track 1.* May 2012.
[9] Navigant. *2013 California Energy Efficiency Potential and Goals Study*. February 2014. The report is available at http://www.cpuc.ca.gov/PUC/energy/Energy+Efficiency/Energy+Efficiency+Goals+and+Potential+Studies.htm.

efficiency can help meet AB32 goals. Navigant will work with the CPUC and stakeholders to develop stretch GHG reduction scenarios.

4. Develop metrics for the CPUC's Energy Efficiency Strategic Plan update.[10] The Plan identifies a number of strategies that move beyond current approaches for energy efficiency resource deployment and lays the groundwork for their implementation. The 2015 Study is expected to inform, as well as be informed by the Plan, by helping to provide metrics, including projections of additional energy savings estimates, for the 2015 Strategic Plan Update Goals. This may include aligning the potential model with strategic plan initiatives, identifying appropriate metrics, characterizing the baseline, developing scenarios, and creating a tracking mechanism.

CPUC policy making informed and directed this study, as outlined in Rulemaking (R.) 09-11-014 and most recently by Decision (D.) 12-05-015, which provided guidance on the 2013-2014 energy efficiency portfolios. D.14-10-046 (Phase I of R.13-11-005) adopted energy efficiency savings goals for 2015 and Phase II of the proceeding will adopt goals for a three year period starting in 2016.[11] The study period spans from 2016-2024 based on the direction provided by CPUC and focuses on current and potential drivers of energy savings in IOU service areas. Analysis of energy efficiency savings in publicly owned utility service territories is not part of the scope of this effort.

The Navigant team and the CPUC have conducted outreach to stakeholders in the development of this model. The comments and questions raised during these meetings have informed the development of the PG Model.

1.2 Scope of this Study

The four primary uses of the 2015 and Beyond Potential Study correspond to the four distinct tasks that will be used throughout the project:

- **Task 1 Potential and Goals Study Update.** This task will inform the CPUC as it proceeds to adopt goals for future IOU energy efficiency portfolios.
- **Task 2: Additional Achievable Energy Efficiency (AAEE) Savings Forecast.** This task will develop savings forecasts for use by CPUC, CEC, and CAISO in long term planning exercises.
- **Task 3: Energy Efficiency Targets for Greenhouse Gas Reductions.** This task will quantify how extensively IOU programs and energy efficiency can help meet AB32 goals.
- **Task 4: Metrics to Support the Strategic Plan Update.** This task will help provide metrics, including projections of additional energy savings estimates, for the 2015 Strategic Plan Update Goals.

The Navigant team is contracted through 2018 to support the development of the PG Model and provide results for each of the four above listed tasks. This report represents the first of multiple updates to the potential study that will occur through 2018. This report focuses on Task 1: Potential and Goals Study Update. Specifically, this report represents the first stage of Task 1 updates (Stage 1). The CPUC and

[10] More information on the Plan can be found at: http://www.cpuc.ca.gov/PUC/energy/Energy+Efficiency/eesp/
[11] Note that the 2016-2018 period is tentative and will ultimately be determined in Phase II of R.13-11-005.

Navigant worked together to determine the appropriate scope of Stage 1 updates given the regulatory timeline for setting 2016 and beyond goals.

1.2.1 Stage 1

Stage 1 of Task 1 is primarily a data update to the PG model to inform 2016 and beyond goals; it is the sole topic of this report. The scope of Stage 1 is to:

» Maintain the 2013 PG Model methodology, infrastructure, architecture, and types of output;

» Correct minor issues where the 2013 PG model methodology is not aligned with current CPUC policy; and

» Rely on new secondary data sources to update the PG model with the latest available information to better inform the 2016 and beyond goal setting process.

The majority of the effort undertaken by the team on Stage 1 was to review and incorporate the latest available data into the study. The CPUC provided the following high level direction to Navigant throughout the data update process:

» Database for Energy Efficient Resources (DEER) data must be incorporated for high impact measures including the DEER2014 Update and DEER2015 Update.[12]

» 2010-12 Evaluation, Measurement, and Verification (EM&V) impact studies should further update DEER data for residential and commercial measures.

» 2010-12 EM&V evaluations should be used to inform updates to Codes and Standards (C&S) analysis, behavior program analysis, and financing analysis.

» The latest California appliance saturation survey studies should be relied upon for key market data.

» In regards to IOU workpapers, the Navigant team should only rely upon those reports that went through a rigorous CPUC review process (however, un-reviewed workpapers could be used to characterize emerging technologies).

» In regards to Industry Standard Practice (ISP) studies, the Navigant team should only rely upon those that are CPUC vetted and approved.

The Navigant team conducted analysis on Stage 1 from November 2014 through June 2015. The majority of the analysis (data collection, model development, and results analysis) was conducted from November 2014 to March 2015. Given the short timeline of Stage 1, the various data update tasks were prioritized by the team along with CPUC input. Table 1-1 lists the Stage 1 key data update activities along with their assigned priority. The priority indicates the relative level of effort allocated to each update activity; high priority items obtained more attention and resources than low priority items. Data collection for high priority updates ended in December 2014 to allow the Navigant team the requisite

[12] The full DEER2016 cannot be incorporated into Stage 1 due to the timeline of the DEER2016 release relative to the timeline of Stage 1. However, the Navigant team did coordinate with the DEER team to best align the study to any new DEER changes and made some high priority adjustments to the potential study in responses based on a draft of DEER2016.

time to review and process the data. Medium and low priority updates continued to receive data through early February at which point data collection activities were stopped in order to deliver draft results on March 17, 2015. Additional, data updates in response to stakeholder comments and CPUC direction were made in early June of 2015, see Section 1.4 for more detail.

Table 1-1: Stage 1 Data Update Priorities

Key Data Update Activity	Stage 1 Priority
Update Residential and Commercial measures with the following data sources: DEER, 10-12 EM&V studies, the Measure Cost Study, and saturation studies	High
Update C&S savings analysis using the 2010-12 impact evaluation study, update methodology to match CPUC policy	High
Update Agricultural, Industrial, Mining, and Street-Lighting to incorporate the latest Industry Standard Practice studies	High
Incorporate the latest non-measure inputs regarding retail rates, building stocks, avoided costs, and utility program costs	High
Update Whole Building Energy Efficiency data using 2010-12 EM&V data, DEER data, CEC building code data, and other available studies	Medium
Update Emerging Technologies data assumptions, specifically review LED assumptions with regards to the California Lighting Quality Standards	Medium
Provide the ability to view measure level results from the model	Medium
Update Behavior and Conservation analysis with latest EM&V and utility data and coordinate with the ongoing CPUC behavior studies	Low
Update Financing analysis with latest EM&V data and coordinate with the ongoing CPUC financing studies	Low

Source: Navigant team discussions with CPUC Staff

1.2.2 Stage 2

Stage 2 will continue to update Task 1 and further refine the data, assumptions, and methodology used to inform the IOU goal setting process. Work on Stage 2 is expected to start in July 2015. The exact scope and timeline for Stage 2 has yet to be determined, the Navigant team is coordinate with the CPUC to better define the scope and schedule. Stakeholders will be invited to participate in the scoping process. The following items are possible updates for Task 1 in Stage 2 (pending further discussions with the CPUC):

» Integrate DEER2016 Update data

» Review Agriculture Industrial, Mining and Street Lighting data to better align with the California market

» Update savings from future codes and standards

» Add new advanced and emerging technologies to the study

» Consider modeling methodology changes as appropriate

» Update whole building initiatives with better cost and market applicability data

1.3 Types of Potential

Consistent with the 2013 Study, the 2015 Study forecasts energy efficiency potential at three levels for rebate programs:

1. **Technical Potential**: Technical potential is defined as the amount of energy savings that would be possible if the highest level of efficiency for all technically applicable opportunities to improve energy efficiency were taken, including retrofit measures, replace-on-burnout measures, and new construction measures. Technical potential represents the immediate replacement of applicable equipment-based technologies regardless of the remaining useful life of the existing measure. Consistent with industry best practices, technical potential does not and is not meant to account for equipment stock turnover. Technical potential represents the potential from individual, equipment based measures. It does not account for behavior programs, IOU claimable savings from codes and standards, or whole building initiatives. In this study, technical potential represents the remaining opportunities for energy efficiency relative to the state of the market as of 2013.
2. **Economic Potential**: Using the results of the technical potential analysis, the economic potential is calculated as the total energy efficiency potential available when limited to only cost effective measures.[13] All components of economic potential are a subset of technical potential. Similar to technical potential, economic potential does not account for equipment stock turnover. The technical and economic potential represent the total energy savings available each year that are above the baseline of the Title 20/24 codes and federal appliance standards.
3. **Market Potential**: The final output of the potential study is a market potential analysis, which calculates the energy efficiency savings that could be expected in response to specific levels of incentives and assumptions about policies, market influences, and barriers. All components of market potential are a subset of economic potential. Some studies also refer to this as "achievable potential." Market potential is used to inform the utilities' energy efficiency goals, as determined by the CPUC.

Market potential can be represented three different ways; each is based on the same data and assumptions though each serve separate needs and provide necessary perspectives.

1. **Incremental savings** represent the annual energy and demand savings achieved by the set of programs and measures in the first year that the measure is implemented. It does not consider the additional savings that the measure will produce over the life of the equipment. A view of incremental savings is necessary in order to understand what additional savings an individual year of energy efficiency programs will produce. This has historically been the basis for IOU program goals.

[13] The default assumption for this study includes all non-emerging technologies with a total resource cost (TRC) test of 0.85 or greater; emerging technologies are included if they meet a TRC of 0.5 in a given year and also achieve the TRC for non-emerging technologies (0.85) within ten years of market introduction. The model includes savings from measure bundles commonly adopted for low income programs; low income programs generally have a TRC less than 0.85 and are not required to be cost effective. These measure bundles are thus included for the purposes of calculating economic potential.

2. **Cumulative savings** represent the total savings from energy efficiency program efforts from measures installed since 2013 including the current program year, and are still active in the current year. It includes the decay of savings as measures reach the end of their useful lives. Cumulative savings also account for the timing effects of codes and standards that become effective after measure installation. This view is necessary for demand forecast, but creates challenges in accounting for IOU program goals.
3. **Life-cycle savings** refer to the expected trajectory of savings from an energy efficiency measure (or portfolio of measures) over the estimated useful life of the measure(s), taking account of any natural decay or persistence in performance over time. Whereas cumulative savings are a backward look at all measures installed in the past that are producing current savings, life-cycle savings accounts for all future savings from measures installed in the current year. Life-cycle savings is used to inform cost-effectiveness evaluations and could be an appropriate basis for IOU program goals.

A large number of variables drive the calculation of market potential. These include assumptions about the manner in which efficient products and services are marketed and delivered, the level of customer awareness of energy efficiency, and customer willingness to install efficient equipment or operate equipment in ways that are more efficient. The Navigant team used the best available current market knowledge and followed these guidelines in developing the recommended market potential:

1. Provide a view of market potential where data sources and calculation methods are transparent and clearly documented.
2. Avoid assumptions and model design decision that would establish goals and targets that are aspirational, but for which the technologies or market mechanisms to attain these goals may not yet be clearly defined.

With these precepts in mind, the Navigant team considers that the market potential presented in this study is a viable basis for energy efficiency forecasting to which load forecasters, system planners, and resource procurement specialists could agree. However, this study may not capture the upper bound on the total amount of energy efficiency that can be achieved. There may be additional energy savings to capture, particularly from systems efficiency and behavior change, which could not be reliably quantified based on past evaluation results available at the time of this study.

1.4 Changes relative to the May 2015 Draft Release

Several data updates have been made to the potential study since the May 2015 release. A draft version of DEER2016 was published for the first time; the release coincided with the potential study's May 2015 release. While the Navigant team was in communication with the DEER team prior to the release, final impacts of key data were unavailable to the Navigant team during the development of MICS. Several updates have been made to the potential study as a result of the DEER team's review of 2010-12 EM&V data and incorporation into DEER2016. Additionally, Navigant reviewed key data sources for the AIMS sectors as well as IOU Low Income Programs. As a result of this data review, the following updates have been made:

- The EUL for all residential CFL measures (basic, specialty, and reflector in indoor and outdoor applications) have been decreased to 3.5 years (previous values ranged from 4.5-11 years depending on the measure). This update was made based on the CPUC's uncertain measure review.[14] This decrease in EUL has two effects: 1) stock turnover of bulbs in the residential sector increases thus slightly increasing the future potential of LEDs, and 2) cumulative savings in the residential sector decreases in future years as CFL savings can only be counted on for 3.5 years.
- Commercial lighting hours of use assumptions have been updated in DEER2016. HOU assumption vary by building type and proportionally impact unit energy savings. In some building types the team observed a 50% decrease in HOUs relative to DEER2015 while other building types remained similar or slightly increased. These changes applied to CFLs, linear fluorescents, and their respective LED equivalents. The net impact of these HOU changes is a decrease in commercial lighting potential. These impacts go into effect starting in 2016 thus calibration is not affected.
- DEER2016 updated the unit energy savings assumptions and net to gross assumptions for residential refrigerator recycling. The unit energy savings decrease on the order of 50% while net to gross increased slightly. The net impact is a significant reduction in savings from residential refrigerator recycling relative to the May 2015 results. These impacts go into effect starting in 2016 thus calibration is not affected.
- Based on verbal and written comments from stakeholders regarding the results from the AIMS sectors, Navigant reviewed key inputs in greater detail. Navigant found a minor update to the AIMS sector was warranted to use the latest available building stock, energy consumption, and building type distribution data available from the CEC. The update lead to a slight decrease in IOU market potential savings.
- Navigant worked with CPUC's low income staff to review and revise the input assumptions regarding low income programs. Savings per participant and estimated number of participants were updated in the model. A key change relative to the May 2015 release is the new assumption that low income programs in their current form will stop operation after 2020, no potential from low income is forecasted in 2021 or beyond. For additional details regarding data updates see Section 3.8.

Navigant made an additional downward adjustment to SDG&E's whole building energy savings at the direction of the CPUC. CPUC Decision 14-10-046 says in regards to whole building savings for SDG&E:

> *"It is going to take some "ramping-up" to achieve such a dramatic increase in savings. Accordingly, we have adjusted SDG&E's 2015 goal to reflect 120% of SDG&E's recent annual savings claims for commercial whole building retrofit programs. This considers (but does not require) a linear, five-year ramp up to the level of savings the draft 2013 Study forecasts for SDG&E."*

The 2015 study shows a decreased savings potential from whole building initiative relative to the 2013 study; however, Navigant made a further adjustment to SDG&E's potential to remain consistent with D.

[14] CPUC. *Ex Ante Update for ESPI Uncertain measures - Compact Fluorescent Lamps 30 Watts and Less.* May 2015.

14-10-046. This adjustment was made based on a 4-year ramp starting in 2016 (similar to the previous 5-year ramp methodology in which 2015 was the first year of the ramp). This ramp assumes 2015 whole building savings for SDG&E are equivalent to the adjusted value found in the SDG&E's 2015 goal and 2019 whole building savings are equal to the 2019 forecast from the PG study. A linear ramp is used between these two years. The result is a small adjustment to SDG&E potential in 2016 through 2018.

1.5 Contents of this Report

This report documents the data relied upon by and the results of the 2015 and Beyond Potential and Goals Study – Stage 1. It does not discuss Task 2, Task 3, or Task 4.

- **Section 2** provides an overview of the study's methodology. Note that the majority of the study's methodology is the same as the 2013 study. Section 2 in many instances refers readers to the 2013 Study for more details on the methodology.
- **Section 3** provides details on the data update process for each key area of the study. Section 3 describes the data sources and process taken to incorporate the data into the PG Model.
- **Section 4** provides the 2015 PG Model results.
  - Section 4.1 discusses the statewide (all IOUs combined) technical, economic and market potential in California.
  - Section 4.2 contains the incremental market potential for each IOU, these are the basis for the IOU goal setting process.
  - Section 4.3 documents the effects of energy efficiency financing on the market potential.
  - Section 4.4 describes how readers can access detailed results from the PG study include end use and sector specific results for each IOU.
  - Section 4.5 compares the results of this study to the results of the 2013 Study.
- **Appendices** provide additional details for key topic areas.

Aside from this report, the following are available to the public:

- **2015 PG Model File –** an Analytica based file that contains the PG model used to create the results of this study;
- **2015 PG Results Viewer –** a spreadsheet viewer that contains detailed results at the measure level for the mid-case scenario (the basis of the results of this study); and
- **2015 PG MICS –** a spreadsheet version of the Measure Input Characterization System documenting all final values for all measures used in the model.

These additional documents and files can be found on the CPUC's website.[15]

[15] http://www.cpuc.ca.gov/PUC/energy/Energy+Efficiency/Energy+Efficiency+Goals+and+Potential+Studies.htm

2. Study Methodology

2.1 Modeling

The primary purpose of the 2015 Study is to provide the CPUC with information and analytical tools to engage in goal setting for the next IOU energy efficiency portfolio. In addition, this study informs forecasts used for procurement planning. The model itself does not establish any regulatory requirements. This section provides a brief overview of the modeling methodology used for the 2015 Potential and Goals Study. The modeling methodology remains the same as that used in the 2013 Study. For more information on the specific methodology for different parts of the model, please reference the 2013 Study report.

The 2015 model forecasts potential energy savings from a variety of sources within six distinct sectors: Residential, Commercial, Agricultural, Industrial, Mining, and Street Lighting. Within some or all of the sectors, sources of savings include:

» Emerging Technology – Emerging technologies were examined for the Residential, Commercial, and Street-lighting sectors. These sectors are modeled using individual measures for specific applications.
» Behavior - For the purposes of this study, the Navigant team defines behavior-based initiatives as those providing information about energy use and conservation actions, rather than financial incentives, equipment, or services.
» Financing - Financing has the potential to break through a number of market barriers that have limited the widespread market adoption of cost-effective energy efficiency measures. The PG Model estimates the incremental effects of introducing energy efficiency financing on energy efficiency market potential and how shifting assumptions about financing affect the potential energy savings.
» Whole Building - In the case of whole-building initiatives, the "measure" is characterized for the building retrofit or house retrofit rather than for specific technology or end uses. Whole building initiatives are modeled for the Residential and Commercial sectors.
» Low Income – The methodology for the low-income sector remains unchanged from the 2013 Study. Data was updated to reflect the most recent information available from the CPUC regarding savings per participant and forecasted participants.
» Codes and Standards - Codes and standards are implemented and enforced either by federal or state governmental agencies. Codes regulate building design, requiring builders to incorporate high-efficiency measures. Standards set minimum efficiency levels for newly manufactured appliances. The Navigant team assessed energy savings potentials for three types of C&S:
    - Federal appliance standards
    - Title 20 appliance standards
    - Title 24 building energy efficiency codes

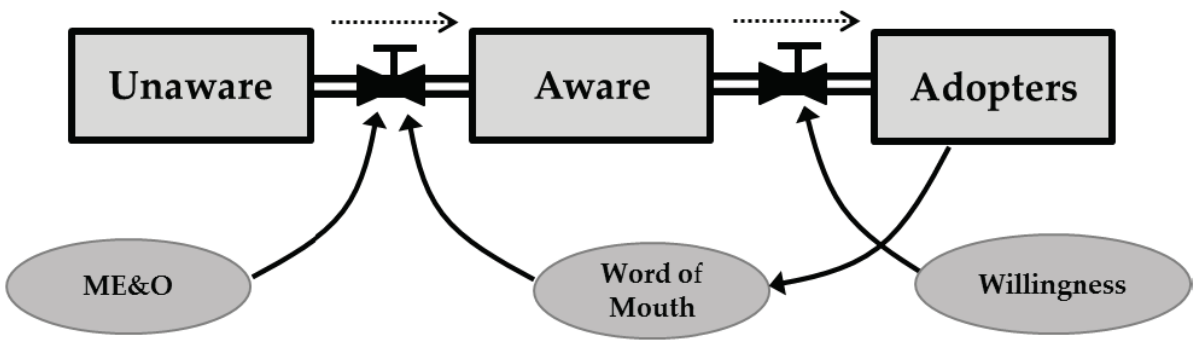
Consistent with the 2013 Study, the 2015 PG Model forecasts three levels of energy efficiency potential (technical, economic, and market) as described earlier in section 1.3 To estimate the market potential for the Residential, Commercial, Mining, and Street Lighting sectors, the model employs a bottom-up dynamic Bass Diffusion approach to simulate market adoption of efficient measures. The bass diffusion model is illustrated in Figure 2-1 and contains three parameters:

» ***Marketing, education, and outreach*** (ME&O) moves customers from the *unaware* group to the *aware* group at a consistent rate annually. Unaware customers, as the name implies, have no knowledge of the energy efficient technology option. Aware customers are those that have knowledge of the product and understand its attributes. ME&O is often referred to as the "Advertising Effect" in Bass Diffusion modeling.

» ***Word of mouth*** represents the influence of adopters (or other aware consumers) on the unaware population by informing them of efficient technologies and their attributes. This influence increases the rate at which customers move from the unaware to the aware group; the word-of-mouth influence occurs in addition to the ongoing ME&O. When a product is new to the market with few installations, often ME&O is the main source driving unaware customers to the aware group. As more customers become aware and adopt, however, word of mouth can have a greater influence on awareness than ME&O, and leads to exponential growth. The exponential growth is ultimately damped by the saturation of the market, leading to an S-shaped adoption curve, which has frequently been observed for efficient technologies.

» ***Willingness*** is the key factor affecting the move from an aware customer to an adopter. Once customers are aware of the measure, they consider adopting the technology based on the financial attractiveness of the measure. The PG Model applies a levelized measure cost to assess willingness; the levelized measure cost considers upfront cash outflows as well as cash outflows

Figure 2-1: The Bass Diffusion Framework is a Dynamic Approach to Calculating Measure Adoption



Source: Adapted from Sterman, 2000.

The Navigant team calculated energy efficiency potential in the industrial and agricultural sectors using a top-down supply curve approach as detailed in the 2013 Study report.

Like the 2013 PG model, the 2015 model was developed in the Analytica software platform. The inputs and user interface are designed for customizability and ease of use. Figure 2-2 depicts a screenshot of the model user interface.

Figure 2-2: The 2015 Potential Goals Model User Interface

2.2 *Methodology Changes Relative to 2013 Study*

As previously mentioned, the modeling methodology remains largely the same as the 2013 study. Table 2-1 lists the key modeling methodology topics, along with the relevant methodology sections from the 2013 study. Readers should reference the 2013 study for additional modeling methodology details. The only noted methodology change from the 2013 study is the treatment of codes and standards; this difference is further explained following the table.

Table 2-1: Comparing 2015 and Beyond Methodology to 2013 Study

Methodology Topic	Modeling Methodology used in this Study	2013 Study Relevant Methodology Sections
Forecasting Adoption of Rebated Measures	Same as 2013 Study	3.3.1 3.3.2.1
Agriculture, Industrial, Mining and Street Lighting Special Considerations	Same as 2013 Study	Section 4 Appendix G – J Appendix T
Emerging Technologies Special Considerations	Same as 2013 Study	3.1.1.1
Whole Building Initiatives Special Considerations	Same as 2013 Study	3.3.2.3 Appendix E
Modeling Behavior Energy Efficiency Initiatives	Same as 2013 Study	3.3.2.5
Modeling Energy Efficiency Financing	Same as 2013 Study	3.3.2.4 Appendix F
Modeling Codes and Standards (Impact on IOU Rebate Programs)	Same as 2013 Study	3.3.2.2 Appendix D.1 Appendix D.2
Modeling Codes and Standards (IOU Attributable Savings)	Modified relative to 2013 Study	3.3.2.2 Appendix D.3

Source: Navigant team analysis (2015)

The 2015 PG Model's analysis of IOU attribute Codes and Standards (C&S) savings follows the same methodology as that used in the 2013 study with one update. Some new California standards supersede efficiency levels set by earlier standards. Two options are available to model the IOU attributable savings these types of standards:

» **Layering:** The first standard produces the first "layer" of savings and each later standard adds another layer of savings.

» **No Layering:** Savings from earlier superseded standards end when a new, more stringent standard takes effect. Only incremental savings from the most recent standard are included.

The CPUC 's Evaluation Study[16] used the Integrated Standards Savings Model[17] developed by CADMUS and DNV GL. Commission staff and evaluators reviewed all of the codes and standards being evaluated in the ISSM model. To qualify as an instance of layering, standards must be adopted separately (not at the same time, as happens when one standard includes two tiers that take effect at different times).

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[16] Cadmus, Energy Services Division and DNV GL. *Statewide Codes and Standards Program Impact Evaluation Report For Program Years 2010-2012*. August 2014.
[17] Cadmus, Energy Services Division and DNV GL. *Integrated Standards Savings Model (ISSM).* Last accessed: January 2015.

Additionally, the superseding code or standard must regulate the same feature(s) of a product.[18] See section 2.2.2 of the Evaluation Study for further details.

Stage 1 uses no layering when calculating results. This is a methodology change relative to the 2013 study which did include layering in accounting for IOU attributable savings. This change is made to the methodology to better align with CPUC policy regarding savings accounting for C&S. The measures that were superseded by later standards and thus are affected by this methodology change were General Service Incandescent Lamps, Tier 2 and Consumer Electronics – TVs.

2.3 Model Calibration

Like any model that forecasts the future, the PG model faces challenges with validating results, as there is no future basis against which one can compare simulated versus actual results. Calibration, however, provides both the developer and recipient of model results with a level of comfort that simulated results are reasonable. Calibration is intended to achieve three main purposes:

» Anchors the model in actual market conditions and ensures that the bottom-up approach to calculating potential can replicate previous market conditions;

» Ensures a realistic starting point from which future projections are made; and

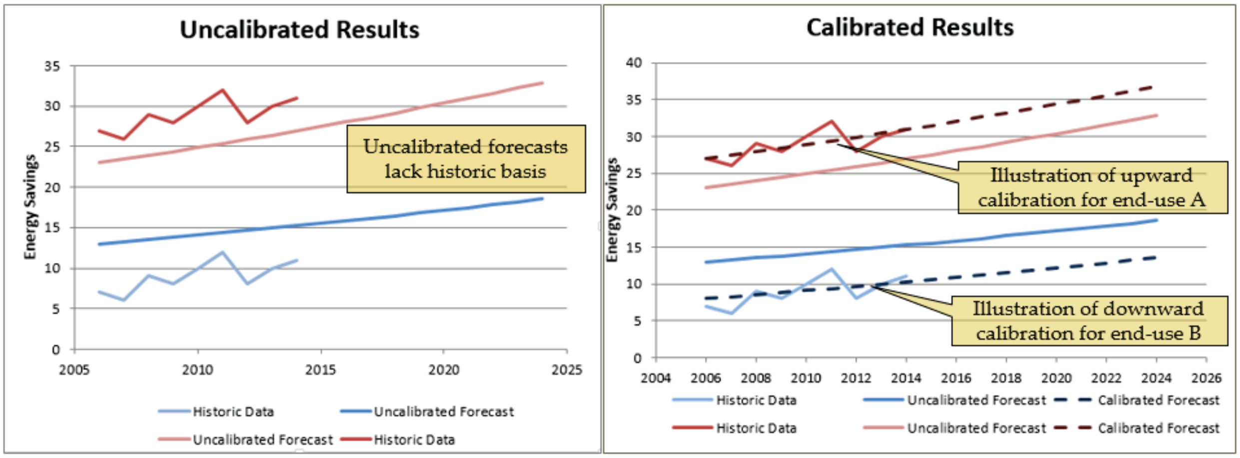
» Accounts for varying levels of market barriers across different types of technologies. The model applies general market and consumer parameters to forecast technology adoption. There are often reasons that markets for certain end uses or technologies behave differently than the norm-both higher and lower. Calibration offers a mechanism for using historic observations to account for these differences.

The PG model is calibrated by reviewing portfolio data from 2006 up through 2012 to assess how the market has reacted to program offerings in the past. The Navigant team used ex-post EM&V data from 2006-2012 as the calibration data and also compared results to the 2013-2014 compliance filing data. The 2013-2014 data was not incorporated into the model calibration because the evaluated data set is not yet available. The Navigant team used the calibration data to adjust willingness and awareness parameters that drive measure adoption over the modeling period. This calibration method (a) tracks what measures have been installed or planned for installation over an historic eight-year period and (b) forecasts how remaining stocks of equipment will be upgraded, including the influence of various factors such as new codes and standards, emerging technologies, or new delivery mechanisms (e.g., financing or whole-building initiatives). This calibration approach is not applied to emerging technologies, as there is no historical basis to adjust future adoption for these technologies.

Figure 2-3 provides a conceptual illustration of how the calibration process affects market potential.

[18] Cadmus, Energy Services Division and DNV GL. *Statewide Codes and Standards Program Impact Evaluation Report For Program Years 2010-2012*. August 2014.

Figure 2-3: Conceptual Illustration of Calibration Effects on Market Potential



Source: Navigant team analysis 2015.

Calibration provides a more accurate estimate of the current state of customer willingness, market barriers, program characteristics and remaining adoption potential. Although calibration provides a reasonable historic basis for estimating future market potential, past program achievements may not perfectly indicate the full potential of future programs. Calibration can be viewed as holding constant certain factors that might otherwise change future program potential, such as:

- Consumer values and attitudes toward energy efficient measures;
- Market barriers associated with different end uses;
- Program efficacy in delivering measures; and
- Program spending constraints and priorities.

Changing values and shifting program characteristics would likely cause deviations from market potential estimates that are calibrated to past program achievements. For more details on the necessity of calibration, the data basis of calibration, effects of calibration, and interpreting calibration please see Appendix A. The appendix also addresses the irrelevance of an "uncalibrated" forecast while offering a supporting discussion about scenario analyses not directly related to the process of calibration but relevant to stakeholder concerns about the interpretation of calibrated results.

2.4 Scenarios

The PG model can run numerous scenarios based on changes to key variables. The 2015 PG Model maintains the same scenario variable options as the 2013 PG model (additional information is available in section 3.3.4 of the 2013 Study). This report presents the results for the mid-case scenario.

- The mid-case scenario has historically been used to inform the IOU goal setting process.
- The mid case scenario is the default setting that the PG model uses to produce results.
- The mid-case scenario in this report retains the same assumptions used in the mid-case scenario in the 2013 study.

» The mid-case scenario is based on population, consumption, and economic inputs defined in the mid-case of the California Energy Commission's 2014 Integrated Energy Policy Report (IEPR).

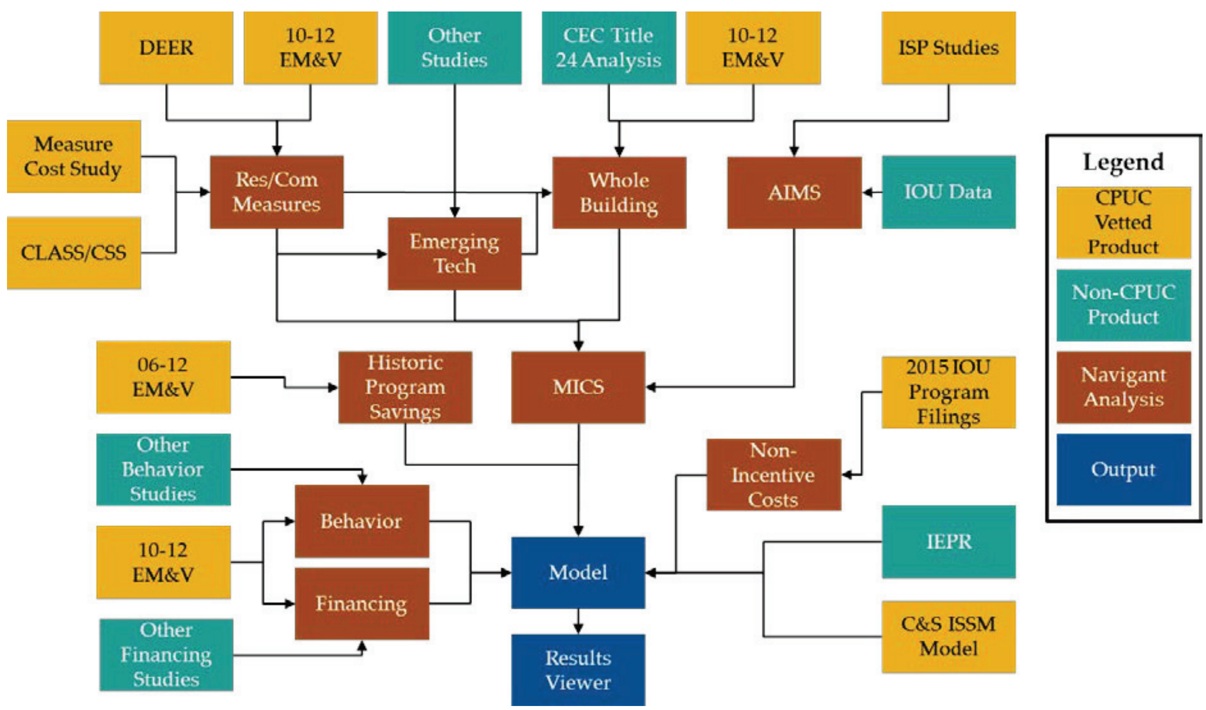
The Navigant team is in the process of developing alternate scenarios. The 2013 study produced additional scenarios (referred to as Additional Achievable Energy Efficiency [AAEE]) to support the 2013 IEPR update process. The CPUC, CEC, and CAISO collaborated to develop an estimate of the energy efficiency savings forecast that could be realized through utility programs that are incremental to the savings already incorporated in the IEPR baseline forecast. The Navigant team will continue to work with the CEC to define the appropriate low and high scenarios to use.

3. Data Sources

As mentioned previously, Stage 1 of Task 1 (Potential and Goals Study Update) is primarily a data update to the PG model to inform 2016 and beyond goals. The majority of the effort undertaken by the team on Stage 1 was to review and incorporate the latest available data into the study.

The data sources relied upon in Stage 1 are vast and varied. Figure 3-1 below illustrates the various produces relied upon for data that feed Navigant analysis that ultimately informs the output of this study. Throughout the data update process, the Navigant team sought to rely upon CPUC vetted products as much as possible. However, in several cases, the team needed to seek alternate data sources where CPUC products did not provide the necessary information. This chapter describes the data update process and sources for key topic areas. The discussion only focus on new data used to inform the Stage 1 of the 2015 Study. In some cases data was not updated and data from the 2013 study was "passed through" to Stage 1; each of the following sections describes what data was "passed through" from the 2013 study.

Figure 3-1: Stage 1 Data Map



3.1 Global Inputs

Global inputs are macro-level model inputs that are not specific to any measure, but rather apply to market segments or sectors. Navigant reviewed the data source for each of these inputs to ensure that the most recent data is utilized for 2015 PG Model update. Table 3-1 provides an overview of all the global inputs within the 2015 model, whether or not the input was updated, and the data source for that update. Each item in Table 3-1 is discussed in further detail in the subsections that follow the table.

No updates were made to the avoided costs, which come from each IOU's Avoided Cost model. Navigant will review these Avoided Cost models again Stage 2 to check for updates.

Table 3-1: Overview of Global Inputs Updates and Sources

Global Input *(description)*	Updated in Stage 1?	Data Source for Update
Building Stocks *(households, floor space, consumption)*	Yes	CEC - *2014 Integrated Energy Policy Report (IEPR) Update and Demand Forecast Forms.* Adopted Feb. 2015. Excel Demand Forecast Forms available at: *http://www.energy.ca.gov/2014_energypolicy/documents/index.html#adoptedforecast*
Retail Rates *($/kWh, $/therm)*	Yes	
Sales Forecasts *(GWh, MW, and MM Therms)*	Yes	
Avoided Costs *(Avoided energy and capacity costs)*	No	No Update in Stage 1, "passed through" from 2013 Study
Historic Program Accomplishments *(Used for calibration)*	Yes	CPUC - *EE Program Tracking Database* Accessed: November 2014
Non-Incentive Program Costs *(formerly Admin. Costs)*	Yes	CPUC - 2015 IOU Planning Submissions - *IOU-2015-Filing-Review-4-17-204.xlsm* Accessed: March 2015

3.1.1 Building Stocks

Building stocks are the total "population" metrics of a given sector, though represented by different metrics for most sectors. Residential building stocks are based on number of households in an IOU's service territory. Commercial building stocks are represented by total floor space for each commercial building type. Industrial and agricultural building stocks are represented by energy consumption. Mining and Street lighting stocks are the number of pumps and streetlights respectively. The residential, commercial, industrial and agriculture building stock metrics are derived from the CEC's IEPR, which is updated yearly by the CEC. Navigant updated the building stocks to reflect the recently released IEPR 2014, adopted by the CEC in February 2015. Sources for mining and street lighting building stocks are discussed further in section 3.4.

Navigant recognizes that within the CEC's IEPR forecast, PG&E and SCE baseline demand forecasts include consumption from Publicly Owned Utilities (POUs) in addition to IOU consumption. The CEC provided Navigant with ratios to adjust the planning area consumption (found within IEPR) down to each IOU's actual service territory consumption for both PG&E and SCE. These ratios, based on 2014 IEPR, are referred to as Service Territory to Planning Area adjustment ratios and are detailed in Table 3-2.

Table 3-2: IEPR Electric Service Territory to Planning Area Adjustment Ratios

	Residential	Commercial	Industrial	Mining	Agriculture	Streetlights
PG&E	90.1%	83.0%	76.6%	86.2%	86.1%	92.0%
SCE	94.0%	91.8%	87.9%	95.7%	62.4%	99.7%

Source: California Energy Commission, 2015

Most POUs in CA do not offer any gas service (currently only the City of Palo Alto and Island Energy offer natural gas service). Due to this, these Service Territory to Planning Area ratios only apply to the electric forecasts of PG&E and SCE. Additionally, PG&E's Gas service territory is larger than its electric service territory to include the SMUD Planning Area, which is reflected within both the 2013 and 2015 PG Models.

3.1.2 Retail Rates and Sales Forecasts

The CEC's IEPR is also the source for retail rates and sales forecasts within the 2015 Study, utilizing 2014 IEPR for the electric rates and sales forecasts and 2013 IEPR for the gas rates and sales forecasts. This was because only electric rates and forecasts were updated in the recently released 2014 IEPR. Updates to the natural gas rates and forecasts are expected this later in 2015 and will be utilized in Stage 2 if they are available. As comparison, the 2013 Study utilized the 2013 IEPR for its sales forecasts and retails rates for both electricity and natural gas. The aforementioned Service Territory to Planning Area ratios were applied to the PG&E and SCE sales forecasts as well.

3.1.3 Historic Rebate Program Achievements

One of the Residential and Commercial sector inputs important for calibration purposes is the historic rebate program achievements for each of the IOUs. These include the ex-post gross program achievements from both the 2006-2009 and 2010-2012 (06-09 and 10-12 hereinafter) program cycles as reported and evaluated by the CPUC. For both the 2013 and 2015 Studies, Navigant obtained these achievements from the CPUC's Standard Program Tracking Database (SPTdb). These achievements are used to inform the historic modeling period and used to calibrate future model projections to account for past program activities. Additional discussion of the calibration process can be found in Appendix A.

The CPUC requires that ex-post gross achievements be utilized whenever possible. In the 2013 Study, the evaluation of the 06-09 program cycle had already been complete and the gross ex-post achievements were utilized in the 2013 Study. These 06-09 achievements were unchanged in Stage 1.

For Stage 1, the historical program achievements for the 10-12 program cycle were updated. The 10-12 program cycle had not been fully reported or evaluated when calibration data was collected for the 2013 PG Study. These evaluations have since completed and the data was obtained in November 2014 for use in Stage 1. The 2013-14 evaluated program achievements are not yet available. Table 3-3 provides the updated 2010-2012 gross ex-post savings utilized in Stage 1.

Table 3-3: 2010-2012 IOU Portfolio Gross Ex-Post Program Savings

	Energy Savings (GWh)		Gas Savings (MM Therms)	
	RES	COM	RES	COM
PG&E	1,743.7	1,249.7	-19.3	23.1
SCE	2,312.4	1,235.1	NA	NA
SCG	NA	NA	24.4	30.1
SDG&E	308.3	300.6	-0.6	7.0

Source: Navigant analysis of Standard Program Tracking Database. 2014 (includes HVAC Interactive Effects)

Appendix A contain tables detailing residential and commercial end use level historic achievements for all years from 2006-2012. Navigant mapped its modeling end-uses to those found within SPTdb, therefore end-use level data may not match exactly. Some program savings were not modeled (such as 'C&S', 'other' or 'unknown' programs) and those savings are included as 'NA' in these tables. Additionally, CFL upstream lighting savings were split between the Residential and Commercial sectors only (52% and 48% respectively) based on the KEMA's Final Evaluation Report: Upstream Lighting Program prepared for the CPUC.[19]

3.1.4 Non-Incentive Program Costs

Non-incentive program costs underwent a thorough review and update based on the 2015 IOU Compliance Filings submitted to the CPUC and found on the DEER website.[20] The 2015 Compliance Filings were utilized since these are most indicative of future non-incentive program costs. These costs were referred to as simply "Administrative Costs" in the 2011 and 2013 Studies, however, this instilled confusion because these include more than simply utility administrative costs. The title was therefore changed to non-incentive program costs, and includes administrative, market/outreach, and implementation (customer service) costs, taken from the 'Program Summary' tab of each IOU's 2015 compliance filings. State and local government partnerships are excluded because they are target exempt programs. Due to high variation in of costs in the agricultural and industrial sectors, a weighted average of Non-Incentive Program Costs for these sectors was applied to the all of AIMS. Table 3-4 provides an overview of the Non-Incentive Program Costs utilized in Stage 1.

[19] CPUC. *Final Evaluation Report: Upstream Lighting Program Volume I.* Prepared by KEMA, Inc., Feb. 2010

[20] Available at *ftp://ftp.deeresources.com/E3CostEffectivenessCalculators/2015IOUsubmissions/* Last Accessed: March 2015

Table 3-4: Non-Incentive Program Costs Summary – 2015 Compliance Filings

	Energy - $/kWh Saved			Gas - $/Therm Saved		
	RES	COM	AIMS	RES	COM	AIMS
PG&E	$0.164	$0.147	$0.095	$3.879	$3.393	$1.637
SCE	$0.141	$0.166	$0.216	NA	NA	NA
SCG	NA	NA	NA	$6.580	$9.536	$13.063
SDG&E	$0.201	$0.095	$0.234	$5.627	$2.262	$7.710

Source: Navigant analysis of 2015 IOU Compliance Filings

3.2 Residential and Commercial Measure Characterization

This section provides an overview of the Navigant team's approach to updating the Residential and Commercial Measure Characterization used in Stage 1. The approach used for the 2013 Study is carried over for the 2015 Study. For the 2013 Study, the Navigant team compiled an extensive set of measure-level data for the two sectors into an online database. To develop the 2013 study measure-level data, the Navigant team combined information from multiple versions of the Database for Energy Efficient Resources (DEER),[21] the Frozen Ex Ante (FEA) database,[22] various IOU workpapers, and saturation studies. Navigant's Measure Input Characterization System (MICS) Online provided a platform for stakeholders to access, review, and provide feedback on measure characterization data. For additional detail regarding the key input variables and initial data sources in the MICS, please refer to the 2013 Study.

For Stage 1 of the 2015 Study, Navigant developed a methodology to refresh the existing MICS with data published after the 2013 Study was completed. The overall architecture of the MICS remained largely the same from 2013 to 2015. This section provides additional detail on the types of measure-level data updates and the sources of each type of input.

The MICS database houses approximately 65,000 unique rows of Residential and Commercial measure characteristics that allow the calculation of technical, economic, and market potential for each measure by climate zone, building type, and service territory. Each of the 65,000 rows of data consists of 87 data parameters that define the measure.

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[21] The Database for Energy Efficient Resources (DEER) contains information on energy efficient technologies and measures. This information includes energy consumption and savings, costs, and other supporting data required to calculate cost-effectiveness and willingness. DEER has been developed for the CPUC through funding from California ratepayers. Interested parties can access DEER at www.deeresources.org.
[22] The FEA (Frozen Ex Ante) is a database developed for the CPUC to house all approved measure-level ex ante data. This includes data on DEER and non-DEER measures. The FEA is housed by the CPUC's Energy Division (ED) on an internal server; access to the FEA data can be requested from ED.

3.2.1 DEER Data

Many of the measures in the MICS developed in the 2013 Study relied on DEER data. Since the 2013 Study was completed, DEER was updated and approved by the CPUC twice due to changes in applicable codes and standards and other minor requests.[23] As such, Navigant updated affected MICS measures with the most recent DEER data. The following DEER updates were included in Stage 1:

» DEER2014 Update: This update was the result codes and standards changes, particularly the California Title 20 Appliance Efficiency Regulations and the California Title 24 Building Energy Efficiency Standards. DEER2014 impacted ex ante unit energy savings for HVAC measures, lighting measures, water heating measures, and other weather-sensitive measures.

» DEER2015 Update: An incremental update to DEER2014 based on United States Code of Federal Regulations, this update affected specific technology groups included in the MICS. The technology groups included split and package air conditioning equipment, water heaters, and gas furnaces.

Navigant collaborated with the Ex Ante Team to fully understand the updates and coordinate the incorporation of the DEER2014 Update and DEER2015 Update data. This collaboration ensured Navigant had the most up-to-date DEER data available for the affected measures and could direct any necessary changes to fundamental structure of those measures. For each affected measure, Navigant extracted data from the DEER database and reconstructed the MICS measure workbooks with the new data. Where necessary, Navigant modified the code and efficient equipment specifications in the measure definitions to match those of the updated unit energy savings data. For more information regarding the integration of DEER data into the MICS, please refer to the 2013 Study.

More recently a draft version of DEER2016 has been released. The CPUC requested Navigant make several critical updates to MICS in response to DEER2016. These updates affected commercial lighting and refrigerator recycling measures (previously discussed in Section 1.4). The team was unable to incorporate the full DEER2016 into Stage 1 due to the timeline of the DEER2016 release relative to the timeline of Stage 1.

3.2.2 2010-12 EM&V Data

Because of the high volume of data in the MICS, Navigant developed a method to prioritize the measure updates based on EM&V data for Stage 1. In general, Navigant selected measures that contributed the greatest to the potential impact in the 2013 Study. Defined as High Impact Measures (HIMs), these measures represented 90% of the potential impact within each sector (Residential and Commercial) and fuel type category (electric and gas).

Table 3-5 presents a count of the measures by Sector, Fuel Type, and End-Use Category included in the EM&V update priority list. Although the list contains most of the updated measures, measures with lower potential impact were also included if they were analogous or related to HIMs. For example, if the baseline unit energy consumption for an HIM changed, the baseline unit energy consumption for all

[23] Updates to DEER outside of the DEER Update process can be found on the change log at http://deeresources.com/files/deerchangelog/deerchangelog.html.

related measures was changed regardless of the potential impact. These corollary updates help to maintain consistency throughout the MICS measures.

Table 3-5: Residential and Commercial Measures Included in the Stage 1 EM&V Data Update

Sector	Fuel Type	Use Category Definition	Use Category Examples	Measure Count
Com	Electric	Lighting	Linear Fluorescents, CFLs, Occupancy Sensors, High-Bay T5s, HIDs	13
Com	Electric	HVAC	A/C and Heating Units, Chillers	7
Com	Electric	Plug-in Appliances/Electronics	Vending Machine Controls, Desktop Computer Power Management	2
Com	Electric	Service/Non-Equipment	HVAC Fault Detection and Diagnostics	1
Com	Electric	Whole-building	HVAC Energy Management Systems	1
Com	Gas	HVAC	Boilers, Thermostats, Furnaces	6
Com	Gas	Service Hot Water	Pipe and Tank Insulation	2
Com	Gas	Whole-building	HVAC Energy Management Systems	1
Com	Gas	Food Service	Fryers	1
Res	Electric	Lighting	CFLs, Plug-In Fixtures, Seasonal Lighting	11
Res	Electric	Plug-in Appliances/Electronics	Refrigerator Recycling, Computer Monitors, Variable Speed Pool Pumps	4
Res	Gas	Service Hot Water	Storage Water Heaters, Instantaneous Water Heaters	2
Res	Gas	HVAC	Furnaces, Duct System Repair	2
Res	Gas	Plug-in Appliances/Electronics	Clothes Washers	1

Source: Navigant team analysis (2015)

Table 3-6 presents the EM&V studies Navigant reviewed and sourced for relevant data updates in Stage 1. Navigant focused the updates on the following key measure parameters:

» Unit energy savings (or factors that contribute to unit energy savings, such as hours of use)

» Equipment specification distributions (e.g., CFL wattages to calculate a weighted average lamp wattage)

» Measure costs

» Measure densities

Navigant engaged the primary authors of the studies during the process to facilitate data transfer and understanding of the available data. The coordination resulted in Navigant's retrieval of data from the full impact evaluation and study databases beyond the data available from within the written report.

Notably, the available studies did not have data applicable to all HIMs, thus some HIMs remained unchanged from the 2013 Study. Similarly, the MICS measures are built from many parameters, and not all parameters are within the scope of or were updated during the EM&V studies. Thus, some parameters of MICS measures remained unchanged from the 2013 Study. Given the timeline of Stage 1, Navigant updated measures based on the EM&V results conservatively, updating measure parameters for which there was a high degree of certainty that the new data were consistent with and an exact matches to the existing parameters.

Table 3-6: EM&V Studies Used for Stage 1 Measure Updates

Author	Study Title	Publication Date	Relevant Data
DNV GL	*Appliance Recycling Program Impact Evaluation*	October 2014	Unit energy savings and net to gross for refrigerator recycling measure
DNV GL	*California Upstream and Residential Lighting Impact Evaluation Final Report*	August 2014	Residential lighting HOU; lamp wattage distributions
DNV GL	*Residential On-site Study: California Lighting and Appliance Saturation Survey (CLASS 2012)*	November 2014	Residential density data
Itron, Inc.	*2010-2012 WO017 Ex Ante Measure Cost Study Final Report*	May 2014	Full measure cost data
Itron, Inc.	*California Commercial Saturation Survey*	August 2014	Commercial density data; lamp wattage distributions
Itron, Inc.	*Nonresidential Downstream Lighting Impact Evaluation Report*	August 2014	Commercial lighting HOU

3.2.3 Key Updates and Outcomes in Stage 1

This section describes observations and outcomes from key updates to the MICS. The studies referenced are those listed in Table 3-6.

» DEER Weather-Dependent Measures: Generally, the updates to weather-dependent measures based on the DEER2014 Update data resulted in relatively minor changes to unit energy savings values.

» Commercial Lighting: DEER2014 Update affected equivalent full load hours for commercial lighting measures, as well as HVAC interactive effects due to the update of weather files. Market-weighted average wattages were updated based on Commercial Saturation Survey (CSS) data. The updates resulted in changes to unit energy savings and effective useful life values. Additional adjustments were made in response to updated HOU data in DEER2016.

» Residential CFLs: Hours of use and market-weighted average wattages were updated based on EM&V results and CA Lighting and Appliance Saturation Survey (CLASS) data. Measure costs were updated based on the Measure Cost Study. EUL was updated based on the CPUC's uncertain measure review.[24] The changes to the MICS characterization influenced the potential results because of the high contribution to overall energy savings of this measure.

[24] CPUC. *Ex Ante Update for ESPI Uncertain measures - Compact Fluorescent Lamps 30 Watts and Less.* May 2015.

- Measure Densities: With the updates to CSS and CLASS, measure densities in MICS were updated to reflect the most recent market saturation and survey data. Densities do not affect unit energy savings or measure costs, but they inform the model calibration and forecast procedures. Nearly all measures in Stage 1 received updated density values, and those values had an important role in the overall measure characterization for Stage 1.

3.2.4 MICS Database and Documentation

A complete MICS database is available through the CPUC website.[25] The database includes detailed descriptions and full characterizations of all measures in the 2015 PG Model. Users can download an Excel workbook that contains the following three tabs:

- Field Definitions: This tab includes a list of the data fields included in the MICS Master Build with a brief description of the fields.
- Measure Update Data Sources: This tab includes a table of the unique measures by sector and fuel type in the MICS Master Build. The table shows the Efficient Case, Base Case, and Code Case for each measure, as well as the relevant data sources used in the Stage 1 update.
- MICS Master Build: This tab includes the complete line-level detail for all sectors included in the 2015 PG Model.

3.3 *Emerging Technologies*

The Stage 1 update for Emerging Technologies (ETs) maintained the same measure list as the 2013 Study and focused on only updating the inputs to the 2015 PG Model where the Navigant team had better information or data availability.

For the purposes of this study, ETs are classified as meeting one or more of the following criteria:

- Not widely available in today's market but expected to be available in the next 1-3 years;
- Widely available but representing less than 5% of the existing market share; and/or
- Costs and/or performance are expected to improve in the future.

Appendix B.4 includes a full list of the ETs modeled, their descriptions, and key ET inputs. The table is organized by End Use category (e.g., Appliance Plug Loads, HVAC, etc.).

3.3.1 Overview of Updates

ETs were only examined for the Residential and Commercial sectors. These sectors are modeled using individual measures for specific applications.

The Navigant team relied on data from various sources to update each ET:

- The Navigant team extrapolated or used directly cost and performance data from DEER where possible. In some cases, some ETs had already been characterized in DEER since the 2013 Study.

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[25] http://www.cpuc.ca.gov/PUC/energy/Energy+Efficiency/Energy+Efficiency+Goals+and+Potential+Studies.htm

For such cases, the Navigant team continued to call these measures ETs to be consistent with the last study (e.g. 0.98 AFUE Gas Furnace).

» IOU workpapers and other case studies provided additional cost and performance data.

» 2010 – 2012 EM&V studies[26] such as "Work Order 017 Ex Ante Measure Cost Study "provided more California-specific data.

» In absence of any California-specific verified data, the Navigant team leveraged data from national studies published by the U.S. Department of Energy (DOE) and the Pacific Northwest National Lab (PNNL) and adjusted to California specific values based on regulatory and market conditions.

» DOE standards and rulemaking review ensured the maximum technically feasible energy efficiency level for many measures and end uses remained same.

» Energy Star's qualified products list and shipment data provided market saturation data.

While the measure categories remained same, their definitions were updated in some cases to reflect the market conditions more closely where we had better data.

» LEDs were redefined based on CFL definitions update. LED definitions are linked to CFL definitions, which were updated based on 2010 – 2012 EM&V studies.

» Residential Water heaters were updated from 0.77 Energy Factor (EF) to 0.82 EF due to the addition of 0.82 EF water heater measure to DEER. If a measure with same or higher efficiency than the corresponding ET efficiency was included in DEER since the 2013 Study, Navigant set the minimum efficiency of the ET to match the highest efficiency description in DEER for applicable measures.

» Self-Contained Refrigerator measure was redefined to be 15% less than energy code due to redefinition of Energy Star products.

» Dishwasher measure was redefined to be EF>1.0 compared to previous round, based on code and competing conventional energy efficient measure update.

» Commercial Refrigeration Fiber Optic LED lighting measure was eliminated. LED display lights have become a standard practice for display case replacements.

Some ETs (along with some conventional technologies) are expected to decrease in cost over time. The Navigant team developed four cost reduction profiles that could apply to various ETs (and non-ETs) in the 2013 Study (see 2013 Study Appendix A). These cost reduction vectors were qualitatively assigned to each ET based on various market drivers that could drive the cost down. Navigant revised these cost reduction assignments based on the further market intelligence developed for the ET measures since the 2013 study (see Appendix B.4).

[26] *2010-2012 WO017 Ex Ante Measure Cost Study.*
2010-2012 WO013 Residential Lighting Process Evaluation and Market Characterization.
2010-2012 WO028 California Upstream and Residential Lighting Impact Evaluation.

3.3.2 Updates for LEDs

The Navigant team also updated data on the cost reduction and performance improvement profiles for LED technologies. LED costs have declined rapidly in recent years (a 50% reduction in market average price from 2011 to 2015) and are expected to continue to decrease in the foreseeable future. Meanwhile, LED efficacy has been increasing and is expected to increase over 40% from 2015 to 2024. This efficacy change will continue to decrease the wattage requirements of LEDs in the future. The PG Model reflects both of these trends.

LED efficacies were updated to reflect market average products and LED efficacies have dropped compared to the 2013 Study. Previous data[27] used in the 2013 Study represented the "best performers" in the market which was based on U.S. DOE technology targets and did not represent the majority of products in the market. New data[28] in Stage 1 represents the average performance and cost which are based on historical data for LEDs. Stage 1 also uses efficacy and cost data specific to LED applications (i.e. General Service and Directional), which allowed Navigant to map the efficacy data to each LED measure more precisely. The mapping of each LED measure to its definition and application can be found in Table B-2 in the Appendix B. LED costs were also updated to market average products based on the most recent DOE pricing study[29] conducted by PNNL.[30]

Then, these LED efficacies and prices were further adjusted to represent LEDs that meet the California Energy Commission's Voluntary Quality LED Lamp Specification[31]. The specifications are based on enhancements to the ENERGY STAR standard with a particular focus on improvements to the color temperature, consistency, and color rendering (with requirements for Color Rendering Index (CRI) greater than or equal to 90). The specification applies to screw-base and bi-pin A-lamp, flame-tip, globe, and spotlight lamps. After December 11, 2013, compliance with the specification for LED lamps became mandatory for IOU incentive program eligibility (this followed a one-year "transition period" that began when the specification came into effect on December 11, 2012). Additional details on the adjustments and data sources can be found in Appendix B.

Figure 3-2 and Figure 3-3 illustrate the resulting difference in LED efficacies used in both studies from 2013 to 2024. The small drop in the LED lamp efficacies from 2013 to 2014 shown in Figure 3-2 is due to the Voluntary Quality LED Lamp Specification going into effect in 2014. Figure 3-4 and Figure 3-5 illustrate the resulting difference in LED prices used in both studies from 2013 to 2024. Additional details on which LED measure are General Service and which are Directional can be found in Table B-2 in the Appendix B.

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[27] Navigant. *Energy Savings Potential of Solid-State Lighting in General Illumination Applications.* Prepared for the U.S. Department of Energy, January 2012.

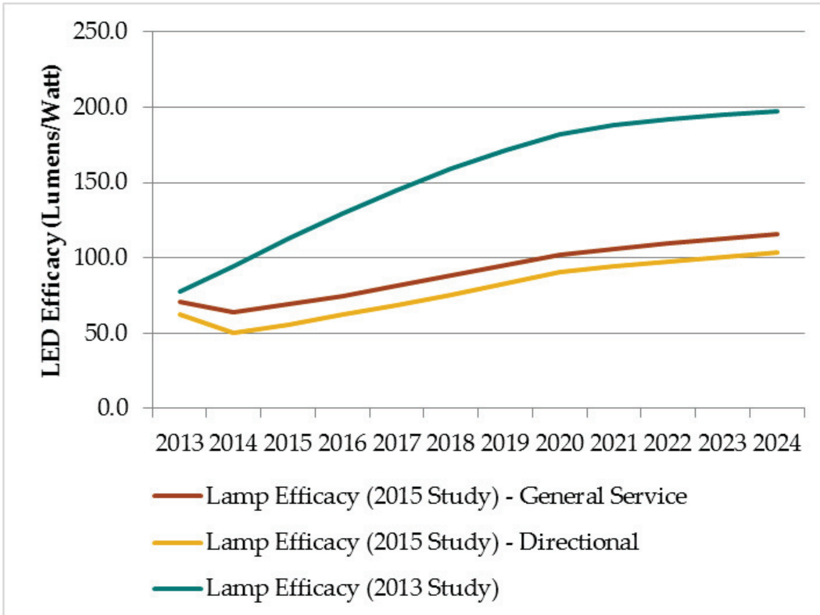
[28] Navigant. *Energy Savings Forecast of Solid-State Lighting in General Illumination Applications.* Prepared for the U.S. Department of Energy, August 2014.

[29] Pacific Northwest National Laboratory. *Solid-State Lighting Pricing and Efficacy Trend Analysis for Utility Program Planning.* Prepared for the U.S. Department of Energy, October 2013.

[30] Although the CPUC Ex Ante Measure Cost Study examined some LED technologies, the information contained in the report was collected in 2013 and is already obsolete because of the rapid evolution of the LED market.

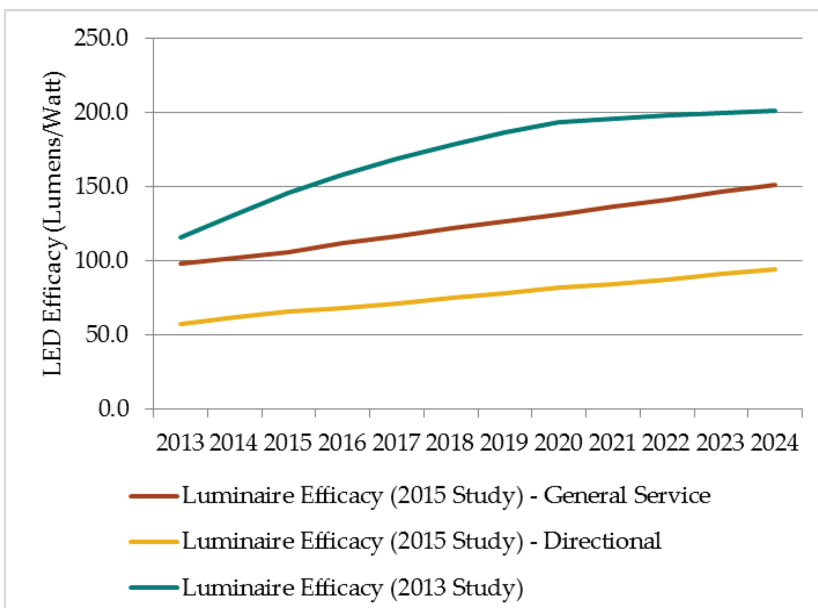
[31] http://www.energy.ca.gov/2012publications/CEC-400-2012-016/CEC-400-2012-016-SF.pdf

Figure 3-2: LED Technology Improvements (Lamps)



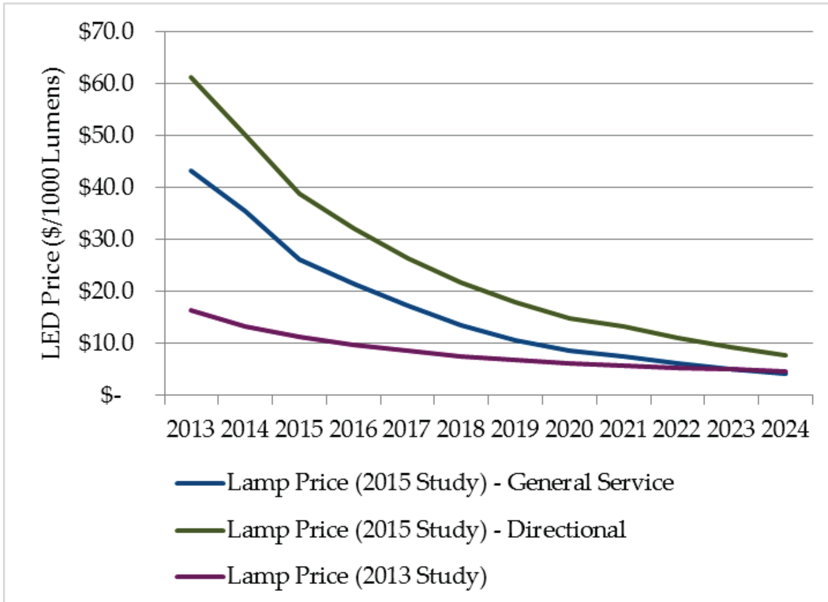
Source: Navigant team analysis 2015.

Figure 3-3: LED Technology Improvements (Luminaires)



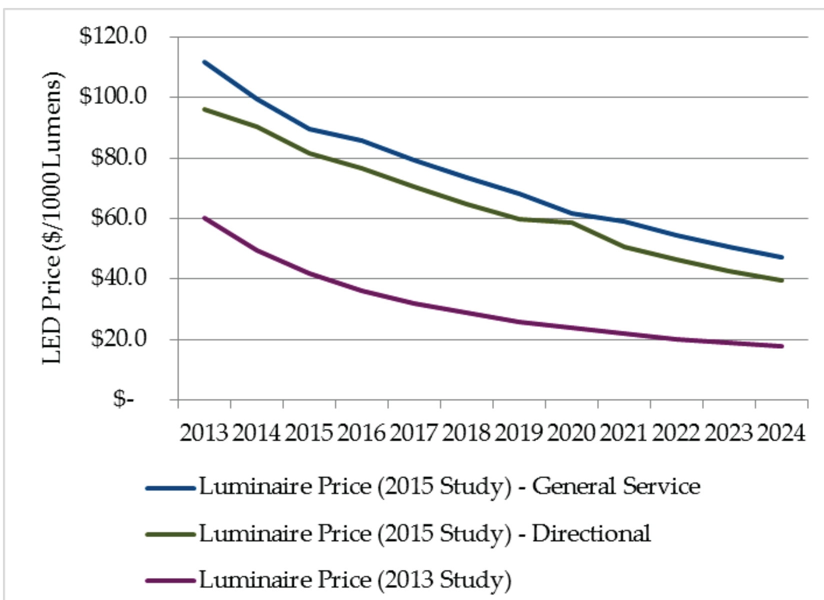
Source: Navigant team analysis 2015.

Figure 3-4: LED Cost Reduction Profiles (Lamps)



Source: Navigant team analysis 2015.

Figure 3-5: LED Cost Reduction Profiles (Luminaires)



Source: Navigant team analysis 2015.

3.3.3 Emerging Technology Risk Factor

In the 2013 Study, the Navigant team assigned a risk factor to each ET to account for the inherent uncertainty in the ability for ETs to produce reliable future savings. Actual future adoption of ETs will vary depending on technology. Some ETs may gain large customer acceptance, capture significant market shares, and generate large savings, while others may falter achieving no market share and no savings. It is impossible to pre-determine which ETs will succeed and which will fail. The ET risk factor acts to de-rate the market adoption of each individual ET. The result is a total ET savings value that is representative of what can be expected of the group of ETs. In Stage 1, the Navigant team revised the risk factors based on the same qualitative metrics that were used previously which included market risk, technical risk, and data source risk. The framework for assigning the risk factor is shown in the 2013 Study.

Navigant's logic for revising the risk factors was based on the success of the measure meeting one or more of the following criteria since the 2013 Study:

» Has overcome some of the market barriers identified previously;

» Has established strong distribution channels;

» Has resolved remaining technology issues ; and/or

» Has produced evaluated energy savings that are equal to current (unevaluated) savings claims.

Appendix B.4 includes the final selected risk factors for each ET.

3.4 Agriculture, Industrial, Mining and Street-lighting (AIMS) Measure Characterization

For Stage 1 of the 2015 Study, Navigant built on the findings developed during the 2013 Study. In the 2013 study, Navigant developed approaches and detailed potential for each of the Agriculture, Industrial, Mining, and Street Lighting (AIMS) sectors.

3.4.1 Overview of AIMS in the 2013 PG Study

The Industrial sector uses a top-down approach to calculate industrial sector potential based on energy efficiency supply curves. This was accomplished by using a variety of data sources, including the Department of Energy's (DOE's) Industrial Assessment Center (IAC). The DOE-sponsored IAC database which provides thousands of industrial measure recommendations and installments based on engineering efficiency audits performed at thousands of industrial facilities. The team used approximately 15,000 energy efficiency recommendations from approximately 10,000 assessments IAC database completed from 2004 to 2012 as the core measure list.[32] The supply curves developed from these IAC measures were then adjusted and vetted using California specific data, including inputs from DEER, CPUC vetted workpapers, relevant inputs from the 2013 potential model Commercial sector inputs, and various sector specific California EM&V studies and market reports. A similar process was used to develop the Agriculture sector forecast. As a result, Navigant's Industrial and Agriculture sector potential forecasts are informed by 167 supply curves defining a specific combination of subsector, end-use, measure type, and fuel.

[32] The IAC database is substantially larger, containing more records than 10,000 assessments. However, the team screened the list for relevant measures and the 2013 Study Appendix provides more details the use of the IAC database.

Navigant's 2013 Study AIMS effort also established the framework to facilitate active and meaningful stakeholder interaction. Specifically, the 2013 Study effort for AIMS started the Industry Standard Practice (ISP) vetting exercise through a detailed ground-floor-level review of the individual codified IAC recommendations to determine their applicability in California. For example, the Navigant and stakeholder team considered established ISP, Title 20/24, local Air Resource Board (ARB, AB32, etc.)[33] positions, Occupational Safety and Health Administration (OSHA) requirements,[34] and other positions on maintenance processes from established IOU programs.[35] These activities accompanied other vetting exercises where potential estimates were reviewed through a comparative metrics exercise that leveraged IOU compliance filings,[36] industrial market characterization reports,[37] and other secondary studies on end-use-specific potentials and forecasts. Navigant conducted these reviews with representatives from the IOUs, the Ex Ante Team, as well as industry subject matter experts (SMEs).

Specific attention was paid to the Mining sector, where several highly developed ISP reports were available and were used to make significant reductions in initial energy effeceiency potential forecasts for that sector, mostly addressing ISPs in the oilfield market. From these studies, Navigant developed measures and potential model inputs that were informed by oil and gas energy efficiency experts,[38] California statewide oil and gas extraction statistics,[39] and additional secondary sources. Inputs were also vetted with the Ex Ante Team to account for ISPs among major and minor oil extractors.

Finally, Navigant developed potential for the Street Lighting sector in the 2013 Study. This effort largely relied on IOU-supplied street lighting inventories that include detailed information on lamp counts, lamp types and technologies, lumens, and wattages. Navigant paired these comprehensive details with other secondary sources to estimate potential for the 2013 Study.

Additional details on the 2013 Study can be found at the CPUC's Energy Efficiency Potential and Goals Study webpage.[40]

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[33] Assembly Bill 32: Global Warming Solutions Act. Air Resources Board. Accessed June 20, 2014. http://www.arb.ca.gov/cc/ab32/ab32.htm

[34] OSHA. Hot Surfaces, 1910.261(k)(11). Accessed June 20, 2014. https://www.osha.gov/pls/oshaweb/owalink.query_links?src_doc_type=STANDARDS&src_unique_file=1910_0261&src_anchor_name=1910.261(k)(11)

[35] 2013-2014 Statewide Customized Retrofit Offering Procedures Manual for Business. Table 1.4.2 Summary of Ineligible Measures. Last Accessed June 20, 2014. http://www.aesc-inc.com/download/spc/2013SPCDocs/PGE/Customized%201.0%20Policy.pdf

[36] 2013-14 Energy Division Investor-owned Utilities Compliance Filing Reviews. Last Accessed June 20, 2014. http://www.cpuc.ca.gov/PUC/energy/Energy+Efficiency/2013-14+IOU+Compliance+Filing+Reviews.htm

[37] KEMA. Industrial Sectors Market Characterization. Metalworking Industry. Last Accessed June 20, 2014. http://calmac.org/publications/Final_metalworking_market_characterization_report.pdf

[38] Navigant team conference meeting with GEP staff via telephone. Global Energy Partners, an EnerNOC Company. (2012). Meeting on November 30, 2012.

[39] CA Dept. of Conservation. 2009 Annual Report of the State Oil and Gas Supervisor. Last accessed: March 2015. ftp://ftp.consrv.ca.gov/pub/oil/annual_reports/2009/PR06_Annual_2009.pdf

[40] CPUC. Energy Efficiency Potential and Goals. Last accessed April 2015. http://www.cpuc.ca.gov/PUC/energy/Energy+Efficiency/Energy+Efficiency+Goals+and+Potential+Studies.htm

3.4.2 2015 Study: Building on the 2013 Study

Stage 1 continued to use the same methodology as the 2013 Study; the team focused on updating inputs. Navigant completed several detailed data gathering and analyses activities to further develop the 2013 AIMS model framework, including the following critical tasks:

- Incorporated recently-completed and published ISP studies that have been reviewed, vetted, and deemed eligible for consideration by the CPUC. Navigant also relied on CPUC guidance and input to establish the list of ISP studies to consider for Stage 1.
- Reviewed the IAC database for recent updates and additions.
- Reviewed other critical data sources for any significant updates. These included the California Integrated Energy Policy Report (IEPR) consumption and retail rate forecast data[41] and sector-specific data such as IOU street lighting inventories.
- Held formal and informal meetings and discussions with stakeholders (e.g., Demand Analysis Working Group [DAWG] Webinar on AIMS Updates). These meetings informed the Stage 1 efforts, but also identified critical issues for consideration in advance of the Stage 2 efforts.
- Reviewed the process by which ISPs are developed and used within the inputs for Industrial, Agriculture, and Mining. This included reviewing secondary sources, IOU-supplied data, and exploring alternative approaches to accounting for ISPs. These topics will be further reviewed during Stage 2.

The following sections provide additional overview of the activities carried out for each AIMS sector for the Stage 1 update. Appendix C provides further details and analyses findings.

3.4.2.1 Industrial

The Navigant team considered the full range of inputs for the Industrial sector to determine where new data sources exist and where existing data sources received significant updates since the 2013 Study.

Stage 1 updates and analysis activities included a review of recently-released ISP studies from the CPUC. Navigant mapped ISPs into the potential inputs based on the studies' relationships to the measures and end-uses, sub-sectors, and in consideration of measure equipment densities (i.e., measure saturation/density, sub-sector applicability, etc.). These ISP-related activities updated a selection of measure de-ratings previously estimated in 2013. This review process also vetted the measures (defined as assessment recommendation codes [ARCs] sourced from the Industrial Assessment Center [IAC]). This vetting exercise supplemented similar reviews completed for the 2013 Study and confirmed the inputs and de-ratings established in 2013.

The team also reviewed other sources for updates to the inputs. Those include the IAC database, the California IEPR, the California Quarterly Fuel and Energy Report (QFER), and IOU planning documents such as IOU Compliance filings. Appendix C.1 notes where updates occurred.

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[41] CEC. California Energy Demand 2015-2025 Final Forecast Mid-Case Final Baseline Demand Forecast Forms. Last accessed: March 2015.
http://www.energy.ca.gov/2014_energypolicy/documents/demand_forecast_sf/Mid_Case/

3.4.2.2 Agriculture

Similar to the Industrial sector, the Navigant team considered the full range of inputs and sources for the Agriculture sector to determine where new data sources exist and where existing data sources received significant updates since the 2013 Study. The Agriculture sector relies on IAC, QFER, and IEPR data. DEER and the Commercial sector Study effort also inform the Agriculture sector.

The Agriculture sector methodology is similar to the Industrial sector. The Agriculture inputs also rely on the updated Industrial sector measure de-ratings in order to reflect ISPs, program eligibility considerations, and other constraints that prevent Agriculture programs from claiming certain savings.

Navigant also accounted for the impacts of drought conditions after it correlated energy consumption increases with drought years. For example, during drought conditions water tables are lower and more energy is required of irrigation pumps to lift water to the surface. The team normalized forecast data to represent typical energy consumption in non-drought years. This was critical given that the PG Model estimates potential as a percent of energy consumption.

Finally, the other sources reviewed for the Industrial sector were also reviewed for the Agriculture sector and updates are noted in Appendix C.2.

3.4.2.3 Mining

Following the Industrial and Agriculture sectors, Navigant conducted a similar review of inputs and sources for the Mining sector. However, unlike the Industrial and Agriculture sectors, the Mining sector relies on an approach more similar to the Residential and Commercial sectors. Inputs are developed from the bottom up and define specific measures instead of more broadly defined end-uses.

Navigant determined that there are no significant updates for measure-specific parameters such as baseline and measure level efficiencies or equipment costs. However, Navigant reviewed the range of sources to both vet the 2013 Study inputs as well as identify any new or updated sources to consider that apply to the market more generally. For example, Navigant observed increasing trends in enhanced oil recovery (EOR) techniques. This relates to injecting pumps and process steam boilers where, over time, more energy in the form of injected water and steam are needed to extract oil that is becoming harder to reach. Stage 1 inputs were updated to reflect this trend.

3.4.2.4 Street Lighting

Navigant also reviewed the inputs for the Street Lighting sector as part of the Stage 1 effort. The 2015 Study generally maintains the methodology developed for the 2013 Study. Namely, Navigant used the IOU-supplied inventories and consumption data from the 2013 Study to estimate baseline and energy efficient measures for customer owned and IOU owned lamps. Navigant also requested and received

2015 street lighting inventories and consumption data from the IOUs and leveraged this data for vetting the inputs.

The most significant change to the inputs includes accounting for forecasted improvements in LED efficacies. The 2013 Study only accounted for forecasted LED cost reductions.

Finally, similar to the 2013 Study approach, the Stage 1 results reflect lamps owned by both customers and IOUs. However, Table 3-7 and Table 3-8 show owner-related metrics so that potential for a given group can be estimated separately.

Table 3-7: Percentage of Baseline and Efficient Street Lamps by Utility

Year	Efficient Lamps (%)*			Baseline lamps (%)**		
	PG&E	SCE	SDG&E	PG&E	SCE	SDG&E
2013	4%	1%	23%	96%	99%	77%
2015	26%	1%	31%	74%	99%	69%

**LED Lamps*
***Non-LED Lamps*
Source: Navigant team analysis of IOU-provided lamp inventories (2015)

Table 3-8: Percentage of Customer Owned and Utility Owned Street Lamps

Year	Customer Owned (%)			Utility Owned (%)		
	PG&E	SCE	SDG&E	PG&E	SCE	SDG&E
2013	74%	17%	81%	26%	83%	19%
2015	76%	15%	81%	24%	85%	19%

Source: Navigant team analysis of IOU-provided lamp inventories (2015)

3.5 Whole Building Initiatives

Whole-building initiatives aim to deliver savings to residential and commercial customers as a group of multiple efficiency measures that are all installed at the same time. Similar to the 2013 Study, Stage 1 of the 2015 Study includes the same whole-building initiatives. Stage 1 data updates are indicated in Table 3-9 below.

Table 3-9: Whole-Building Measures Stage 1 Updates

Whole-Building Measure Name	Stage 1 Data Updates
Commercial New Construction Level 1	Same as 2013 Study
Commercial New Construction Level 2	Same as 2013 Study
Commercial New Construction Level 3	Same as 2013 Study
Commercial New Construction ZNE	Updated data
Commercial Renovation Level 1 – 14% Savings	Updated data
Commercial Renovation Level 2 – 28% savings	Updated data
Residential New Construction Level 1	Same as 2013 Study
Residential New Construction Level 2	Same as 2013 Study
Residential New Construction Level 3	Same as 2013 Study
Residential New Construction ZNE	Updated data
Residential Renovation Energy Upgrade CA - Basic Path (MF only)	Updated data
Residential Renovation Energy Upgrade CA - Flex Path (SF Only)	Updated data
Residential Renovation Energy Upgrade CA - Advanced Path (SF Only)	Updated data

Source: Navigant team analysis, 2015

In the 2013 Study, the Navigant team developed estimates of energy savings and costs for each whole-building measure listed in Table 3-9 and described in Appendix E of the 2013 Study report. The following sections discuss the key updates made to date in the 2015 Study. The final values for savings, cost, measure life, and other key model inputs can be found in the MICS spreadsheet.

3.5.1 Commercial and Residential New Construction ZNE

Table 3-10 provides the Commercial and Residential New Construction ZNE updated sources for Stage 1. PG&E is in the process of conducting a ZNE study, results of which will be incorporated into Stage 2.

In general, baseline construction costs increased slightly since the 2013 Study, which is reflective of the recovery of the construction industry over the last few years. For single family homes, baseline electricity, electric demand and natural gas consumption (kWh/sf, kW/sf and therms/sf) decreased slightly. For multi-family homes, baseline electricity consumption (kWh/sf) increased by about 40 percent. Baseline electric demand (kW/sf) and natural gas demand (therms/sf) for multi-family homes both decreased.

Table 3-10: Commercial and Residential New Construction ZNE Data Updates

Data Items	Data Source
Baseline construction costs	Reed Construction Data Inc., RS Means Square Foot Estimator: http://www.rsmeansonline.com
2013 Title 24 Residential Code-Baseline Energy Consumption	Single and multi-family electricity, electric demand and natural gas consumption updated by California Energy Commission, CBECC-Res 2013 Std. Design Results, January, 2015.

3.5.2 Commercial Renovation Level 1 and Level 2

In the 2013 Study, Commercial Renovation Level 1 and Level 2 bundles were developed by the Navigant team. Data was developed for each IOU territory and each building type. A "bundle" of measures was assembled for each initiative that represents the weighted average installation of measures by a typical participant. In assembling these bundles, only measures from the MICS were eligible for inclusion in these bundles.[42] Each bundle was developed to include gas and electric measures, assuming no overlap between the two fuel types.

Stage 1 updated the 2013 Study bundles to reflect the latest Commercial MICS measure data, without altering the specific individual measures included in the bundles. The specific measures included in the bundles will be evaluated in Stage 2 of the 2015 Study.

3.5.3 Residential Renovation Energy Upgrade California

For the Residential Renovation Energy Upgrade California (EUC) measures, Navigant collaborated with DNV GL who conducted the *2010-2012 Whole House Retrofit Impact Evaluation*.[43] The EUC evaluation study and the EUC program tracking data detailed in Table 3-11 were used to provided updated information for Stage 1.

Table 3-11: Commercial Retrofit Level 1 and Level 2 Data Updates

Data Source Name	Data Source
Whole House Retrofit Impact Evaluation	CALMAC ID: CPU0093.01 http://www.calmac.org/publications/CPUC_WO46_Final_Report.pdf
CPUC 2013-2014 EUC Program Tracking Data	EDCentralServer.com, alltracking1314q7_wroadmap.sas7bdat

Stage 1 modeled the same three measure bundles as the 2013 Study which include: Basic Path, Flex Path and Advanced Path. Compared to the 2013 Study, Stage 1 data resulted in a decrease in electricity, demand and natural gas savings and an increase in the energy efficiency material cost.

[42] See 2013 Study Appendix Section E.1 for additional context on the sources of data for measures eligible for the bundles.

[43] DNV GL – Energy, 2014. *Whole House Retrofit Impact Evaluation. Evaluation of Energy Upgrade California Programs.* Work Order 46. Prepared for the California Public Utility Commission, Energy Division. Final Report: September 9, 2014. CALMAC ID: CPU0093.01, http://www.calmac.org/publications/CPUC_WO46_Final_Report.pdf

- **Basic Path:** Whole House Retrofit Impact Evaluation study did not include multifamily homes, so the data for calculating Basic Path savings remained the same as the 2013 Study.
- **Flex Path:** The Flex Path savings were developed from the impact evaluation report, but in 2010-12 most retrofits were either Advanced or Basic. The Flex path savings were developed by assuming a weighted average of 2/3 Advanced and 1/3 Basic to make up Flex. The reasoning behind this assumed weighting was the measures that were installed with high frequency in 2010-12 Advanced were similar to the Flex options in roughly two-thirds of the cases, while the remaining third of the Flex options resembled the Basic path.
- **Advanced Path:** Whole house Retrofit Impact Evaluation data was used to update the electricity, electric demand, natural gas savings and energy efficiency cost data.

The measure saturation/density is another change worth noting. The measure saturations/densities were determined based on utility customer population data from Residential Appliance Saturation Study (RASS)[44] and Energy Information Administration (EIA)[45] records, final tracking data used for the impact analysis covering program years 2010-12, and the latest available tracking data for program years 2013-14. The data for the impact evaluation specifically checked for homes that had gas and electric or gas only and avoided double-counting customers. The available data for 2013-14 could not be fully de-duplicated in a similar manner, so the data was used with some slight adjustments based on the ratio of tracked records to unique customers from the impact evaluation. Between the 2013 Study and the 2015 Study, the efficienct technology density (number of EUC program participants/existing building stock) increased as additonal households particpated in the program.

Concern exists that the cost data reported for the program does not just include energy upgrade measures costs but general project retrofit costs that do not all impact energy savings. Additional efforts are already being made by the study team to further evaluate the true incremental costs for a EUC program participant.

3.6 Codes and Standards

Codes and Standards (C&S) impacts on energy efficiency potential are modeled two ways:

- C&S reduces the Unit Energy Savings (UES) for IOU rebated measures, thus decreasing the savings claimable by IOU programs
- IOUs can claim a portion of savings from C&S that come into effect through the IOU C&S advocacy programs.

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[44] RASS 2009. Volume 1: Methodology. Table 2-2A-B Individually Metered Sample Design. http://websafe.kemainc.com/rass2009/Uploads/2009_RASS_Volume%201_%20FINAL_101310.pdf

45 RECS Survey Data 2009. Household Demographics by Year of Construction. Table HC9.3 Household Demographics of U.S. Homes, By Year of Construction, 2009. http://www.eia.gov/consumption/residential/data/2009/#undefined

3.6.1 Impacts of C&S on IOU Programs

As new C&S come into effect, the code basis above which IOUs may claim energy savings changes. As high efficiency C&S come into effect, code baselines increase and claimable unit energy savings decrease. The impact of C&S on UES over time is represented by a time series set of multipliers. The time series multipliers are referred to as the "C&S vectors".

A "vector" of impact percentages was developed for each incentive program measure to capture the impact of C&S in each year. C&S impact vectors are used as the input to the PG Model to assess the total impact of new state and federal standards to potentials of incentive programs. C&S vectors are multiplied by the UES values to create a time series of above-code, claimable UES for use in the model. For incentive program measures not affected by any new standards, values of the impact percentages are 100%. As new C&S come into effect, impact percentages below 100% are derived. In some cases impact percentages can drop to 0% (if the new code is equal to or surpasses the efficiency level of the measure). The methodology for determining impact percentages remains unchanged from the 2013 study.

MICS unit energy savings values in Stage 1 represent the unit energy savings of a measure in 2015. Thus, code vectors are built such that vectors equal 100% in 2015 and decline in value over time as new C&S come into effect. In some special cases the C&S vector is less than 100% in 2015 (if the measure in MICS was not updated to reflect current codes in 2015).

Updates to the MICS data as well as the passing of new C&S required updates to the C&S vectors in Stage 1. New C&S considered in this study include 2015 and 2018 Federal Residential Clothes Washers Energy Conservation Standards[46] and 2018 Federal General Service Fluorescent Lamps Energy Conservation Standards[47].

The C&S impact vectors for each measure are listed in Appendix D.

3.6.2 Net IOU Attributable C&S Savings

The CPUC 's 2010-12 C&S impact evaluation study[48] used the Integrated Standards Savings Model (ISSM)[49] developed by CADMUS and DNV GL to estimate net IOU attributable C&S savings. For C&S that were modeled in ISSM, the 2015 PG Model uses ISSM data. For all other C&S, the 2015 PG Model uses data from the 2013 Potential and Goals Study[50]. The 2013 model leveraged data from the 2006-08 impact evaluation. Table 3-12 lists the scope of each of the past to C&S evaluation studies in terms of the number and types of codes and standards evaluated. The 2015 potential adds new data on 40 codes and standards from the 10-12 evaluation; this is data that was not available in the 2013 study. A full list of

[46] http://www1.eere.energy.gov/buildings/appliance_standards/product.aspx/productid/39

[47] http://www1.eere.energy.gov/buildings/appliance_standards/product.aspx/productid/70

[48] Cadmus, Energy Services Division and DNV GL. *Statewide Codes and Standards Program Impact Evaluation Report For Program Years 2010-2012.* August 2014.

[49] Cadmus, Energy Services Division and DNV GL. *Integrated Standards Savings Model (ISSM).* Last accessed: January 2015.

[50] Navigant Consulting, Inc. *2013 California Energy Efficiency Potential and Goals Study*. February 2014.

the modeled C&S, their compliance rates, effective dates, and policy status (on the books, possible, or expected) are listed in Appendix D.

Table 3-12: C&S Groups and Evaluation Scope

IOU C&S Group	Number and Type of Codes and Standards	Evaluation Scope
2005 Title 20	22 appliance standards	2006-2008 PY Evaluation
2006-2009 Title 20	11 appliance standards	2010-2012 PY Evaluation
Federal	7 appliance standards	2010-2012 PY Evaluation
2005 Title 24	19 building codes	2006-2008 PY Evaluation
2008 Title 24	22 building codes	2010-2012 PY Evaluation

Source: Cadmus, Energy Services Division and DNV GL. Statewide Codes and Standards Program Impact Evaluation Report for Program Years 2010-2012. August 2014.

The 2013 study made use of "realization rates" in forecasting savings from unevaluated C&S. These realization rates were determined as part of the 2011 Potential and Goals Study. The realization rates were only applied to unevaluated C&S and were based on evaluated C&S (from the 2006-08 evaluation period). Stage 1 removes the use of realization rates (setting them to 100%) as the ISSM used in the 2010-12 evaluation does not include realization rates for unevaluated C&S. This allows the potential study to better align with EM&V data.

As previously noted in section 2.2, the 2015 study uses no layering when analyzing net IOU attributable C&S savings. This is change in methodology relative to the 2013 study.

3.7 Behavior Energy Efficiency

Updates to the behavior model used best available data for existing behavior programs, while considering the difference between operational, or usage-based, and equipment savings. For both residential and non-residential behavior, the team used the same methodology and parameters as the 2013 study. This included using building operator certification (BOC) and home energy report (HER) programs as the representative programs. The team reviewed over 75 sources (listed in Appendix E. , as well as stakeholder comments. Table 3-13 summarizes the parameters for each sector, as well as the key sources driving the Stage 1 updates for each parameter.

Table 3-13: Summary of Behavior Model Parameters and Stage 1 Update Key Sources

Non-Residential		Residential	
Parameter	**Key Source(s)**	**Parameter**	**Key Source(s)**
% of floor space impacted	Assessment of commercial building stock data	Participation rates	CPUC data on current and planned CA IOU participation rates (HER programs)
Usage-based savings per 1,000 square feet	Research Into Action and Energy Market Innovations, *Summary Of Building Operator Certification Program Evaluations*, November 2011; and others	Savings rates (kWh and therms) per household	Most recent available CA IOU HER program evaluations (except SCG)
		Portion of household savings from usage-based behavior	Review of 21 sources addressing the topic (nationwide)

3.7.1 Non-Residential Behavior Model Updates

For the Stage 1 update the team reviewed recent studies evaluating BOC programs and also revisited studies reviewed for the 2013 model.[51] Some of the recent studies were explicit about energy savings and reductions in energy densities associated with changes in operating practices in contrast to savings that result from equipment upgrades, while other reports didn't distinguish between which of these two activities generated savings.

The aggregate impact of this research resulted in the team increasing the savings in electricity associated with changes in operating practices from 41 to 58 kWh per thousand square feet of participating building space. This was based largely on a 2011 Energy Market Innovations, Inc and Research into Action report which clearly analyzed and documented the energy savings associated with changes in operating practices that result from BOC programs.[52] The team did not find a compelling reason to increase natural gas savings associated with building operator training.

In addition to increasing the savings per unit of building area, the team also adjusted the forecast of market penetration of operator training to suggest that BOC practices will reach higher levels of saturation within the study timeframe. The increased level of participation will be driven by those organizations that operate portfolios of buildings, such as city, county, state and federal governments, and institutional organizations like the primary and secondary education sectors, and operators of large commercial buildings portfolios, such as real estate investment trusts. For example, a 2014 study

[51] All four IOUs began offering BOC training in 2002. Research Into Action, *Evaluation of the 2002 Statewide Building Operator Certification And Training Program*, November 2003, Pacific Gas & Electric. BOC was introduced in the 2011 potential study as being the most direct estimate of 'behavioral savings', however these types of program do not represent the universe of programs that achieve operational savings.

[52] Research Into Action, BOC-Expansion Initiative Market Progress Evaluation Report #1, April 2014 , Northwest Energy Efficiency Alliance

indicated that approximately 40% of BOC training involves staff associated with government and institutional facilities. [53] The BOC saturation estimates used in the 2015 update forecast that by 2026 training will impact roughly 3.5% of commercial building space annually, with cumulative training impacting roughly 23% of commercial space.

Based on a recent report recommending 5 years, the team did not revise its 2013 model assumption (also 5 years) on persistence of training impacts.[54] Lastly, the team did not increase the gas savings estimates because there wasn't compelling research to support such a change. Table 3-14 summarizes the non-residential inputs for the 2013 and 2015 models.

Table 3-14: Non-Residential Inputs for 2013 and 2015 Studies

Non-Residential Inputs	2013 Study	2015 Study
Portion to usage-based behavior (kWh/1,000 sq. ft.)	41	58
Portion to usage-based behavior (therms/1,000 sq. ft.)	5.6	5.6
2015% of commercial floor space impacted	0.95%	1.00%
2026% of commercial floor space impacted	3.00%	3.45%

Source: Navigant team analysis, 2015

3.7.2 Residential Model Updates

For the 2015 residential behavior model, the team updated the three model parameters included within the 2013 model based on data from each IOU's latest evaluation reports, correspondence with the CPUC as well as review of EM&V reports for similar programs (listed in Appendix E. . Below we summarize each of these parameters; 1) HER program participation, 2) HER savings results from billing analyses, and 3) an assessment of HER savings allocated to equipment and behavior-based usage.

1. **HER Program Participation:** The team updated HER program participation rates to reflect prior, current and anticipated HER program participation provided by the IOUs and the CPUC.[55] While participation in the HER programs may change over time (either due to attrition from program opt-outs or moving out of the service territory, or due to changes to program implementation such as adding new cohorts), there is no good way to forecast that specific change in participation beyond discussion with the IOUs. As such, we chose to apply the participation amounts at a constant rate based on conversations with the IOUs. However, the behavioral model uses IOU forecasted populations that increase over time (from 2016-2024). As

[53] Impact Evaluation of the California Statewide Building Operator Certification Program, CALMAC Study ID: CPU0069.01. Prepared for the California Public Utilities Commission by Opinion Dynamics Corporation, February 2014. Table 67. PY2010-2012 BOC Participants by Market

[54] Research Into Action, *BOC-Expansion Initiative Market Progress Evaluation Report #1*, April 2014 , Northwest Energy Efficiency Alliance

[55] CPUC. *SW EA Monthly Metrics Report All IOUs Oct 2014_111314.xlsx.* January 2014; CPUC. *Email from Valerie Richardson.* February 2015. Emails from each IOU in April 2015.

such, while we applied a constant participation rate as a percentage, the rate is multiplied by an increasing future population so the absolute number of actual HER participants increases over time.

2. **HER Percent Savings per Household from Billing Analysis:** The team applied per-household adjusted savings rates for each IOU from their respective 2013 program evaluation reports. For PG&E, we calculated a weighted average using each individual wave treatment participation numbers and per household savings percentages to derive a single value that could be applied across the full treatment population.[56] For SCE, we applied the average percent savings per household as reported in the latest evaluation report.[57] The gas savings rate for SCG is based on the Advanced Meter Semi-Annual Report from August 2014.[58] For SDG&E, we applied the average percent savings per household as reported in the latest evaluation report.[59]
3. **Allocation of Equipment or Behavior based savings:** While billing analyses do a good job of determining a per-household savings rate, the data cannot show what percent of the savings come from installation of energy efficient equipment or changes in behavior. To account for this, previous iterations of the PG study estimated the percent of the HER program savings assumed to be from behavior change to ensure that the model appropriately counted only behavior based changes.[60] Upon review of the recent EM&V studies cited in Appendix E. , we determined that this factor is no longer needed for two reasons: 1) utility rebated equipment is already discounted from the evaluated savings estimates percent via double counting analyses[61], and 2) program evaluations establish that the remaining savings, which consists of usage based and non-utility rebated equipment based savings, is the true influence of the behavior program.

As a result of these updates, the model increased the estimate of electricity and gas savings associated with residential behavioral programs. The increases are primarily due to the increase in participation rates and the removal of the equipment vs. behavior calculation. Table 3-15 summarized the residential inputs for the 2013 and 2015 models.

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[56] The PG&E EM&V report does not provide an aggregate percent savings per household value, we leveraged information from the following reports and correspondence with DNV-GL to derive this value. 2013 PG&E Home Energy Reports Program . n/a. DNV-GL. 2015; 2013 PG&E Home Energy Reports Program. n/a. NEXANT. 2015
[57] SCE's Home Energy Report Program Savings Assessment: Ex-Post Evaluation Results, Program Year 2013, Final Report. Applied Energy Group, October, 2014: CALMAC Study ID: SCE0365.01, pp. v.
[58] The current SCE behavior program is implemented as part of SCE's Advanced Metering Infrastructure deployment. As such, Navigant based the SCG savings estimates on the August 2014 Advanced Metering Semi-Annual report provided by SCE staff. Nexant, Evaluation of Southern California Gas Company's 2013-2014 Conservation Campaign Submitted to Southern California Gas Company, August 29, 2014.
[59] SDG&E Home Energy Reports Program, 2013 Impact Evaluation, ED Res 3.3, DNV-GL, October 2014, pp. 2.
[60] See the 2013 study for more details.
[61] Double-counting analysis identifies and removes any energy savings that occurred from HER participants participating in both an IOU-rebated program and HER program.

Table 3-15: Residential Inputs for 2013 and 2015 Studies

Residential Inputs	PG&E	SCE	SCG	SDG&E
Participation Rates 2014-2026 -- % of Residential Population				
Assumes constant rates of participation, applied to shifting number of customers in each IOU territory by year.				
2013 Study	5.00%	5.00%	5.00%	5.00%
2015 Study	22.62%	4.96%	0.82%	16.00%
kWh Savings Rates 2014-2026 -- % per Household				
Assumes constant savings rates.				
2013 Study	1.80%	1.80%	n/a	1.50%
2015 Study	1.08%	1.40%	n/a	2.60%
Therm Savings Rates 2014-2026 -- % per Household				
Assumes constant savings rates.				
2013 Study	1.30%	n/a	1.30%	0.90%
2015 Study	0.61%	n/a	1.30%	2.00%
Behavior vs. Equipment				
2013 Study	67.00%	67.00%	67.00%	67.00%
2015 Study	100%	100%	100%	100%

Source: Navigant team analysis, 2015

3.8 Low Income Programs

The Navigant team reviewed the low income sector forecast and model inputs with staff from the CPUC and the IOUs determined additional edits relative to the 2013 study were necessary to align with recent data. The two key inputs reviewed and updated for the low income sector were 1) unit energy savings (savings per participant) and 2) forecasted number of participants.

The average savings per household as reported in the Energy Savings Assistance (ESA) Annual Reports provides the most accurate and transparent approach to defining unit energy savings (UES) for the low income segment. The team analyzed these reports focusing on reported savings from 2011 through 2014. Table 3-16 provides the final UES values used in the 2015 model and compares the value to that used in the 2013 study. The final values used in the 2015 study are the average of reported savings per participant from 2011 to 2014. SCE KWh savings increased significantly while PG&E and SDG&E decreased. All estimates for demand savings per participant decreased relative to the 2013 study. Gas savings per participant decreased for PG&E and SDG&E while increasing for SCG.

Table 3-16: 2015 Potential Model UES Input Assumptions – Average Savings per Treated Household

Utility	2013 Model	2015 Model
KWh/Participant		
PG&E	391	349
SCE	286	378
SDG&E	397	333
SCG	-	-
KW/Participant		
PG&E	0.24	0.08
SCE	0.29	0.14
SDG&E	0.23	0.03
SCG	-	-
Therms/Participant		
PG&E	20	15
SCE	-	-
SDG&E	21	17
SCG	20	27

Source: Navigant team analysis of ESA Annual Reports

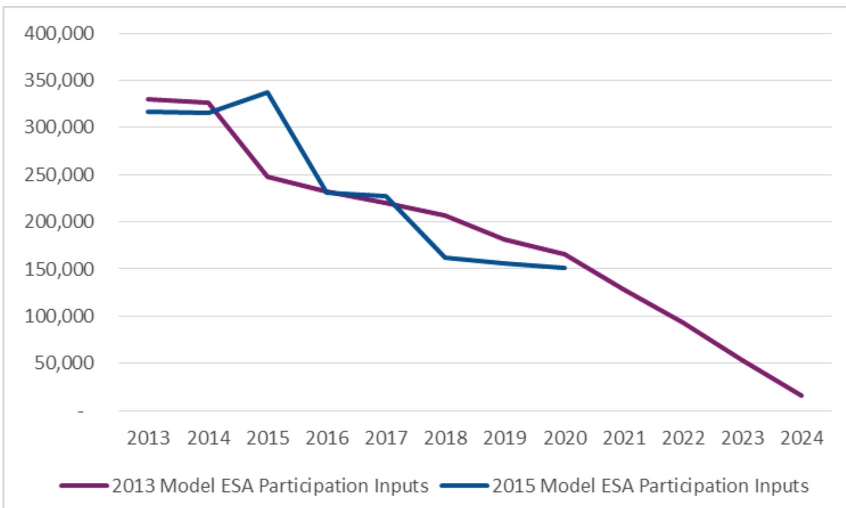
The Navigant team also updated the model's low income program participation forecasts to align more closely with IOU participations forecasts and with current CPUC policy stating that all eligible and willing ESA program candidates would be served by 2020. Table 3-17 provides the recommended participations forecasts for 2015 through 2020, while Figure 3-6 provides a comparison of the final 2015 model participation forecasts with forecasts used the and 2013 potential models. The final 2015 forecasts does not extend beyond 2020 because CPUC policy beyond that date is currently uncertain. The forecasts for participation in the 2016 to 2020 period are relatively consistent though lower than the 2013 study assumptions.

Table 3-17: Low Income Program Participation and Forecast by Utility[62]

Year	Forecast of Total Homes Treated				
	Total	PG&E	SCE	SDG&E	SCG
2015	337,645	119,940	87,389	20,316	110,000
2016	231,316	47,000	54,000	20,316	110,000
2017	227,316	43,000	54,000	20,316	110,000
2018	162,316	38,000	54,000	20,316	50,000
2019	155,816	31,500	54,000	20,316	50,000
2020	150,876	26,560	54,000	20,316	50,000

Source: Navigant team analysis of ESA Annual Reports

Figure 3-6: Comparison of ESA Participation Forecasts



Source: Navigant team analysis of ESA Annual Reports

3.9 *Energy Efficiency Financing*

The CPUC has recognized financing as an energy efficiency resource program[63]. In the 2013 Study, Navigant developed a new approach to estimate the savings impact from financing; the approach considers financing as a mechanism influencing customer choices by reducing market barriers such as hassle factor, liquidity constraint, and high up front cost[64].

[62] 2015 – 2020 participation forecasts are net of any retreatment or add-back assumptions
[63] CPUC Decision 12-05-2015, May 8, 2012 and Decision Approving 2013-14 Energy Efficiency Programs and Budgets, October 9, 2012
[64] Gillingham, Newell, and Palmer. (2009). "Energy Efficiency Economics and Policy." *Resources for the Future*, 2009. Available at: http://www.rff.org/documents/RFF-DP-09-13.pdf

The 2015 Study follows the same methodology and analytical approach as the 2013 Study. We leveraged the CPUC led Statewide Finance Baseline Residential study[65] and California-specific business credit score data to update residential and commercial sector market characteristics in the 2015 Study. The key areas of data updates include:

- **Eligible population**: Navigant identified residential and non-residential population eligibility as a key area of data update for Stage 1. Navigant conducted additional research on California specific residential and commercial customer credit score distribution. The CPUC led Statewide Finance Baseline Residential study obtained over 11,000 consumer credit data points from Experian. Consistent with the California Alternative Energy and Advanced Transportation Financing Authority (CAEATFA) financing pilot program customer credit score minimum requirement, Navigant assumes residential customers with FICO score above 580 are eligible for financing. Similarly, Navigant collected 10,000 business credit score data points from Experian and assumed that businesses with low to medium credit risks are eligible for financing.
- **Interest rates**: The California Statewide Finance Baseline Residential Study includes a mystery borrower analysis, the study collected over 400 interest rate quotes from California banks and credit unions. Navigant updated the market interest rate assumption in the PG model accordingly.
- **Implied Discount Rate reduction**: Based on the preliminary findings from the Statewide Finance Baseline Residential study, the percent of residential customers citing upfront cost as a market barrier is higher than Navigant's previous estimation. Navigant has made adjustments to the implied discount rate reduction for the single family and multi-family sectors.

Table 3-18 summarizes the data updates for Stage 1.

Table 3-18: Summary of Financing Model Data Update

Input	2013 Study Value	2015 Study Value	2015 Study Source
Single Family Sector Interest Rate	9%	8%	Mystery Borrower Analysis, PY2013-2014 California Statewide Finance Baseline Residential Study under Work Order ED_O_FIN3
Single Family Eligible Population	63%	98%	Experian Consumer Credit Data, access date: Nov 19, 2014
Commercial Eligible Population	20%	77%	Experian Business Credit Data, access date: Mar 2, 2015
Single Family Sector Implied Discount Rate Reduction*	11%	14%	Residential Baseline Survey, PY2013-2014 California Statewide Finance Baseline Residential Study under Work Order ED_O_FIN3
Multi-Family Implied Discount Rate Reduction	13%	20%	Residential Baseline Survey, PY2013-2014 California Statewide Finance Baseline Residential Study under Work Order ED_O_FIN3

[65] Work performed under Work Order ED_O_FIN3

As shown in Table 3-18, the eligible population for single family sector and commercial sector increased significantly based on the primary credit data. In addition, the implied discount rate reduction for the single family sector and the multi-family sector increased, implying higher savings estimated from financing in Stage 1. Navigant left other financing model assumptions intact; the 2013 Study report captures details on other modeling assumptions.

4. Results

4.1 Statewide Potential

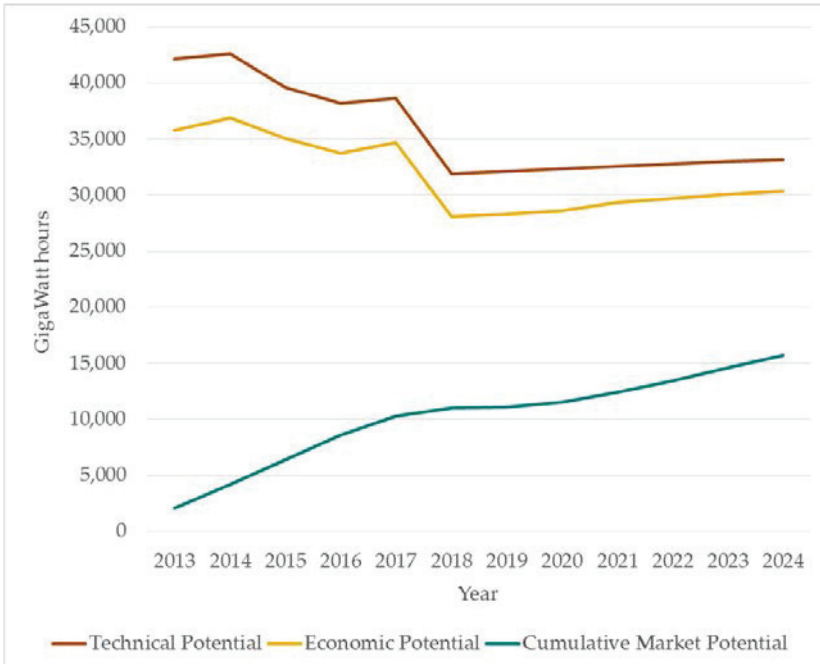
4.1.1 Technical, Economic and Cumulative Market Potential

Figure 4-1 through Figure 4-6 illustrate the statewide technical economic and cumulative market potential from IOU equipment rebates for electric (GWh), demand (MW) and gas (MMTherms) as well as savings as a percent of sales.[66] Theses graphs do not show IOU claimable savings from C&S advocacy programs or behavior programs nor do they include the effects of energy efficiency financing. The figures represent the remaining potential starting in 2013 (i.e. the effects of previous installations of high efficiency equipment prior to 2013 are accounted).

Figure 4-1 shows a technical potential of approximately 38,000 GWh in 2016 and an economic potential of approximately 33,700 GWh. Cumulative market potential grows at a relatively constant rate from 2013 to 2017 when its trajectory slows. This change in trajectory is due to the effects of new lighting C&S that come into effect in 2018 and decrease the IOU claimable savings. Technical and economic potential also decrease in 2018 due to changes in lighting C&S. Figure 4-2 shows statewide technical and economic electric potential as a percent of sales start at approximately 21% and 18% respectively in 2016 and drop to below 16% by 2024. Cumulative market potential grows to approximately 8% of sales by 2024. Figure 4-3 and Figure 4-4 show similar trends in demand potential.

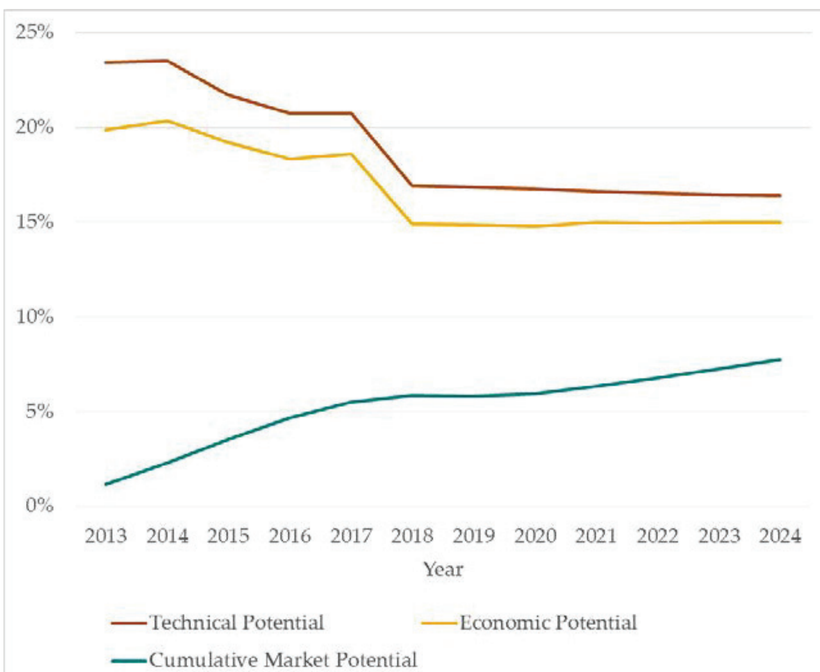
[66] Savings as a percent of sales reflects the value calculated when dividing energy efficiency potential in any given year by the forecasted energy consumption for that year. Forecasted energy consumption is sourced from the CEC.

Figure 4-1: Statewide Electric Technical, Economic and Cumulative Market Potential



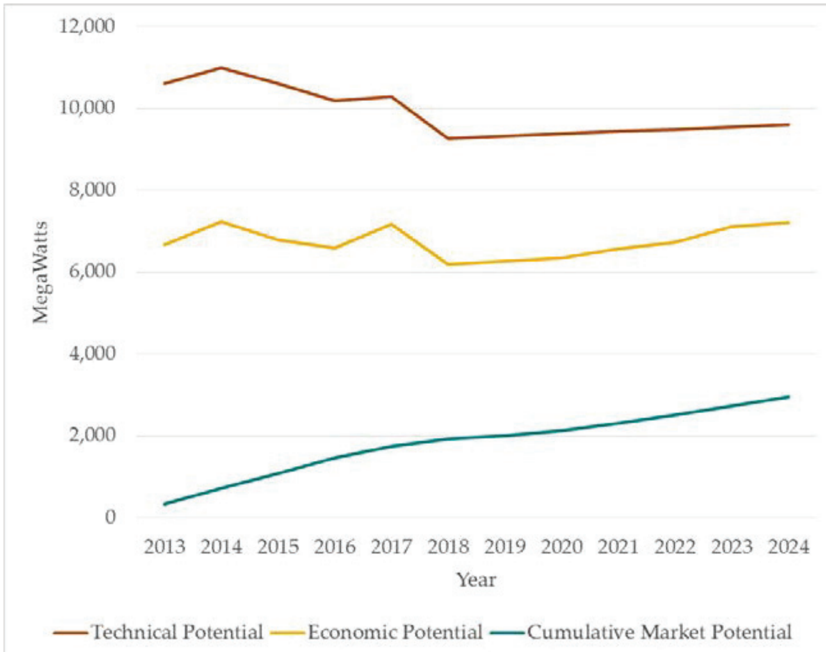
Source: June 2015 PG Model

Figure 4-2: Statewide Electric Potential as a Percent of Sales



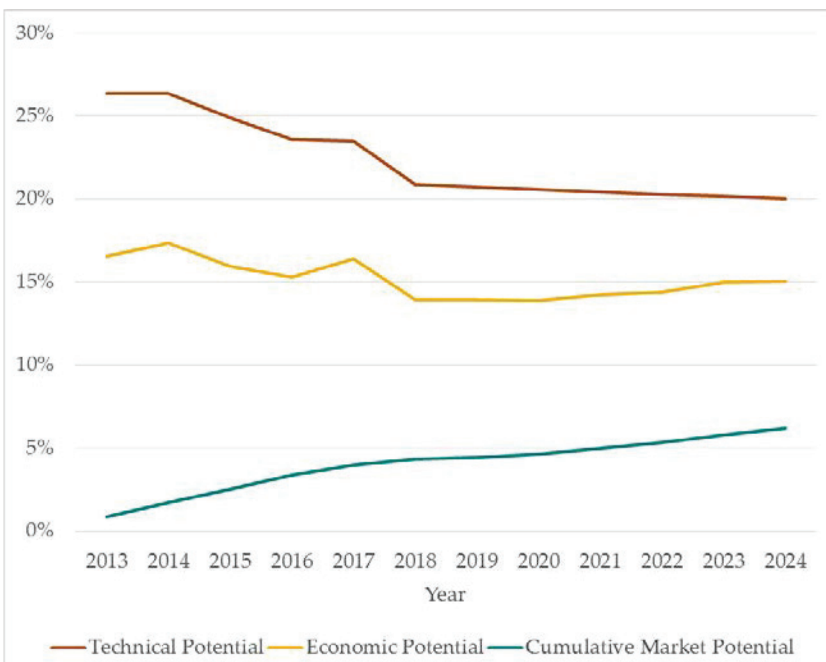
Source: June 2015 PG Model

Figure 4-3: Statewide Peak Demand Technical, Economic and Cumulative Market Potential



Source: June 2015 PG Model

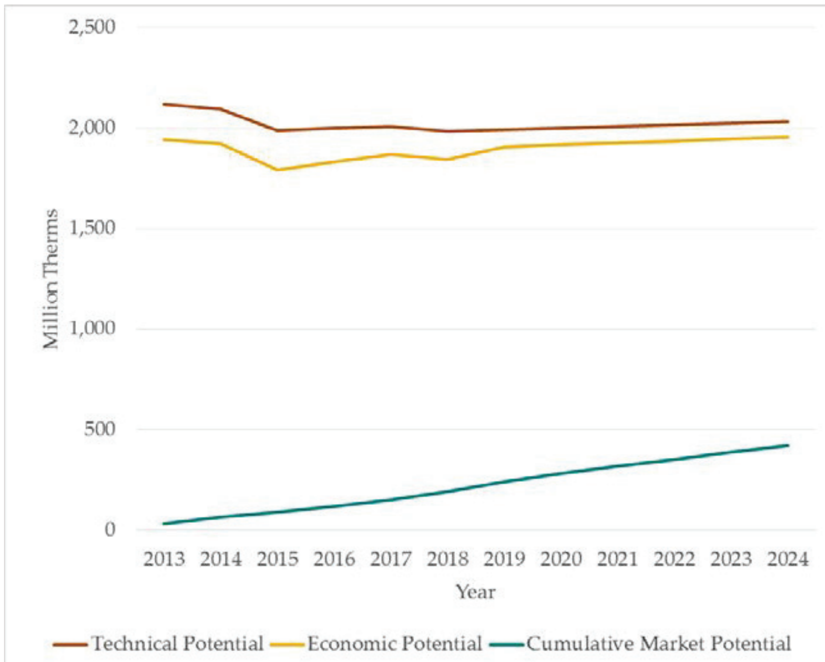
Figure 4-4: Statewide Peak Demand Potential as a Percent of Sales



Source: June 2015 PG Model

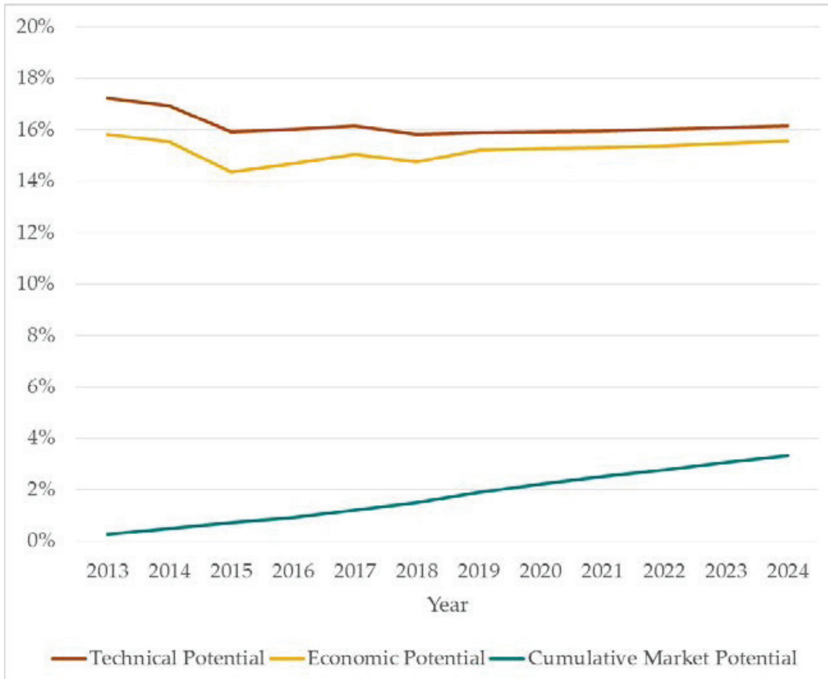
Figure 4-5 shows a technical potential of approximately 2,000 MMTherms in 2016 and an economic potential of approximately 1,800 MMTherms. Cumulative market potential grows at a relatively constant rate throughout the study period. Figure 4-6 shows statewide technical and economic gas potential as a percent of sales start at approximately 16% and 14.5% respectively in 2016 and stay relatively consistent through 2024. Cumulative market potential grows to approximately 3.3% of sales by 2024.

Figure 4-5: Statewide Natural Gas Technical, Economic and Cumulative Market Potential



Source: June 2015 PG Model

Figure 4-6: Statewide Natural Gas Potential as a Percent of Sales



Source: June 2015 PG Model

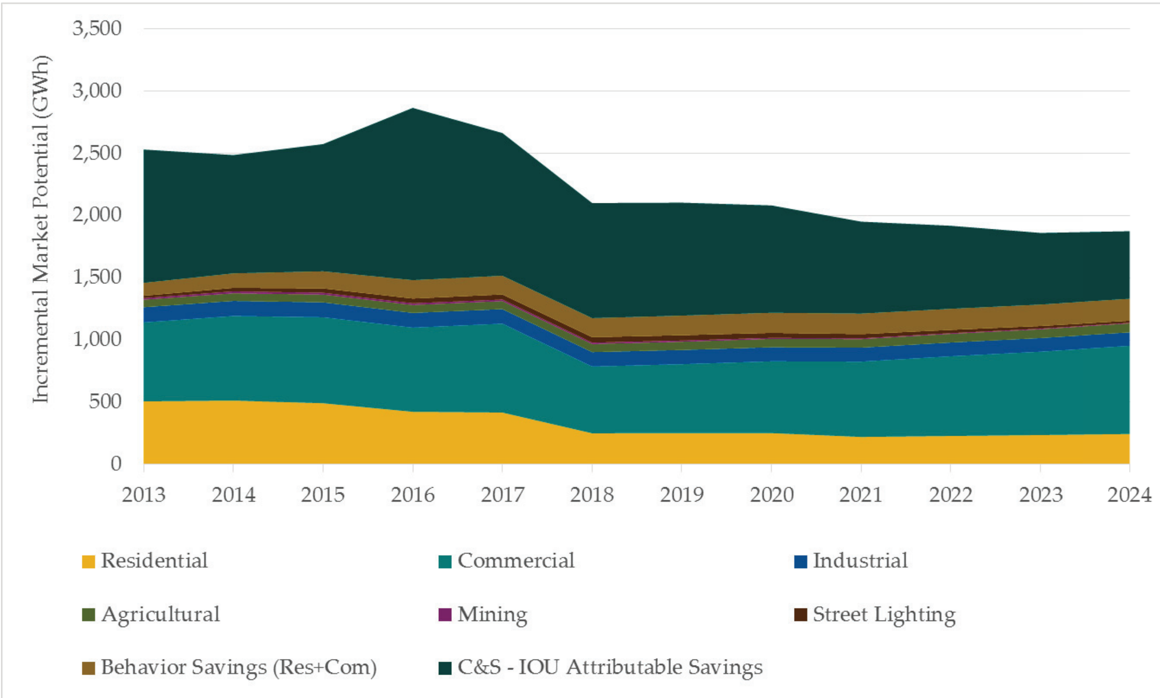
4.1.2 Incremental Market Potential

Figure 4-7 through Figure 4-9 illustrate the statewide incremental market potential from IOU programs for electric (GWh), demand (MW) and gas (MMTherms) respectively. Theses graphs include IOU claimable savings from C&S advocacy programs and behavior programs but they do not include the effects of energy efficiency financing.

Figure 4-7 shows a large portion of IOU potential comes from IOU attributable C&S savings. Residential and Commercial rebated equipment has historically contributed a significant amount of savings to IOU programs and will continue to do so through 2017. In 2018, changes in lighting C&S act to reduce IOU claimable savings. The AIMS sectors remain a small portion of future potential. IOU behavior programs provide more electric savings than the agriculture, mining and streetlighting sectors combined.

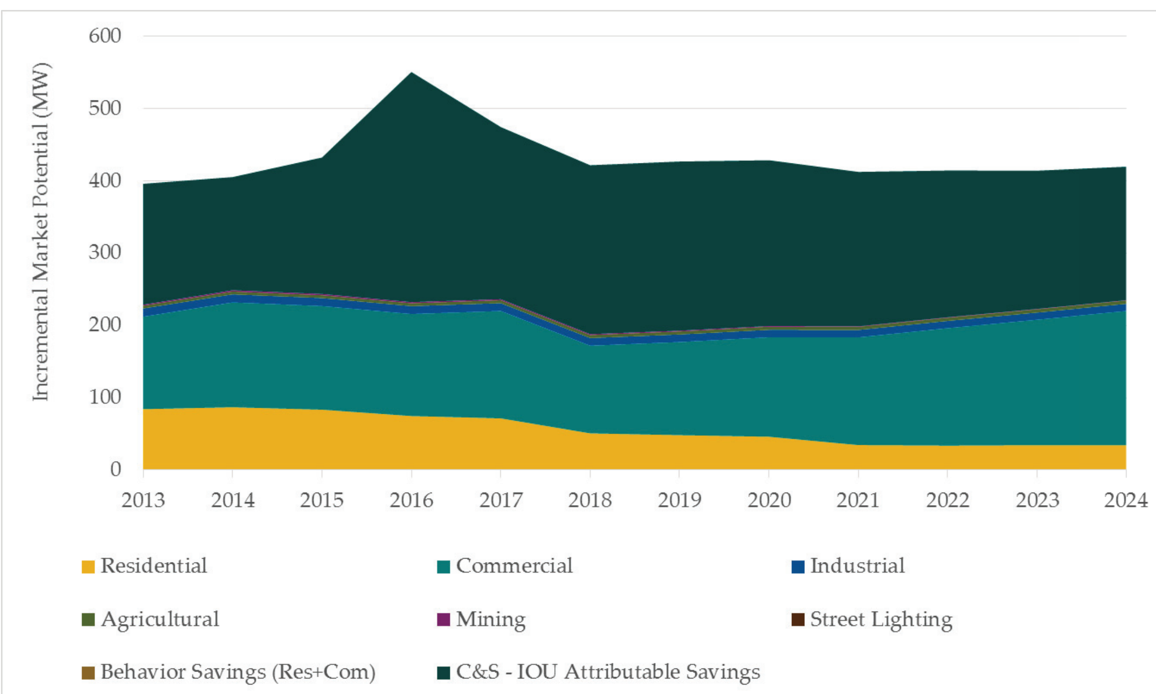
Figure 4-8 shows similar trends for peak demand savings with a few noted differences: behavior programs and street lighting measures do not have any quantified IOU claimable savings potential. Figure 4-8 also shows a spike in expected demand savings in 2016 from C&S. This spike is due to expected 2016 Title 20 HVAC standards regarding air filter labeling.

Figure 4-7: Statewide Incremental Electric Potential



Source: June 2015 PG Model

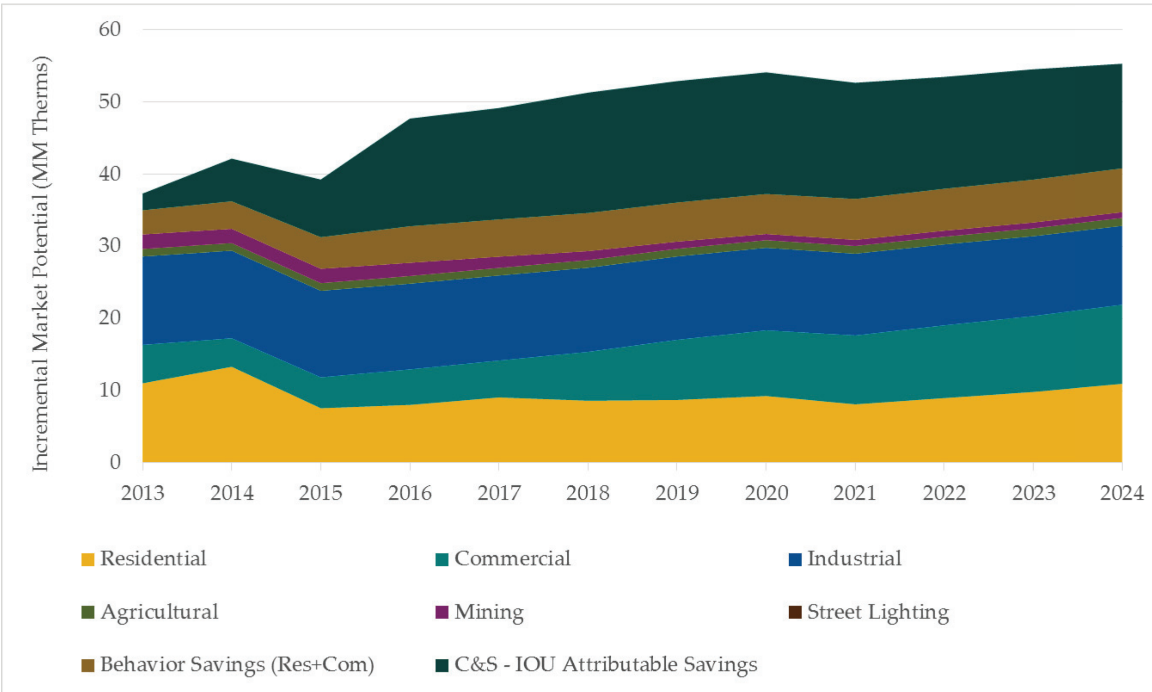
Figure 4-8: Statewide Incremental Demand Potential



Source: June 2015 PG Model

Figure 4-9 shows larger contributions by the Industrial and Mining sectors towards total gas savings potential. Residential and Commercial savings are expected to grow in 2016 and beyond. C&S savings will continue to play a role in IOU program potential but is not as significant of a contributor when compared to electric savings. Like electric potential, IOU behavior programs provide more gas savings than the agriculture, mining and streetlighting sectors combined.

Figure 4-9: Statewide Incremental Natural Gas Potential



Source: June 2015 PG Model

4.1.3 Incremental Market Potential as a Percent of Energy Sales

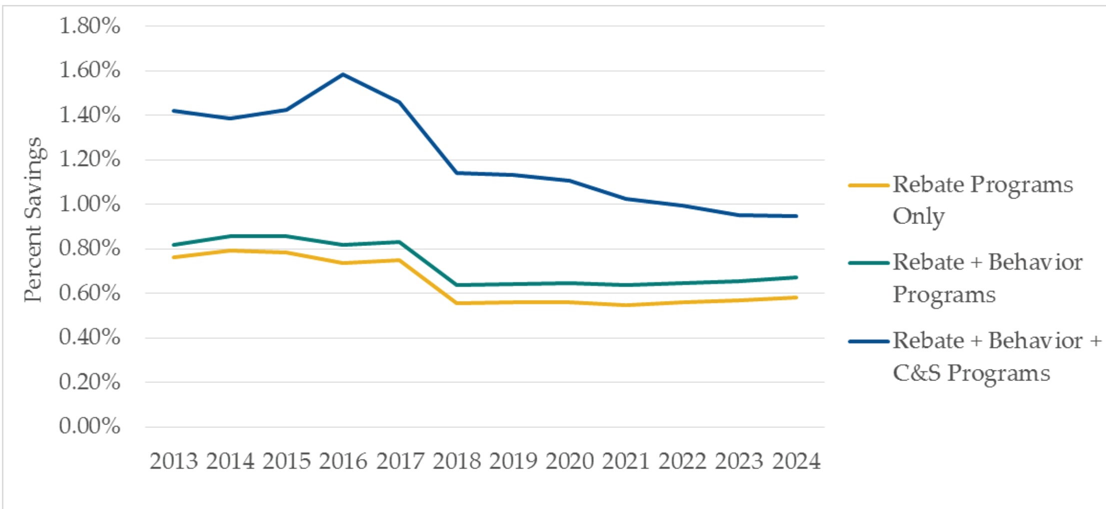
The proposed Assembly Bill 1330 would create an Energy Efficiency Resource Standard (EERS) in California; a statewide target for electric and natural gas efficiency savings. AB 1330, as currently written, would set the following targets:

- Incremental electric savings achieved of no less than 1.5% in 2020 and 2% in 2025
- Incremental natural gas savings achieved of no less than 0.75% in 2020 and 1% in 2025
- Percent savings shall be determined based upon the average retail sales of electricity and natural gas of the immediately preceding three years

Given these possible targets, the study calculated the percent savings by dividing incremental market potential by retail energy sales forecast from the CEC. Retail sales were converted to a three-year historic rolling average per the language of AB 1330.

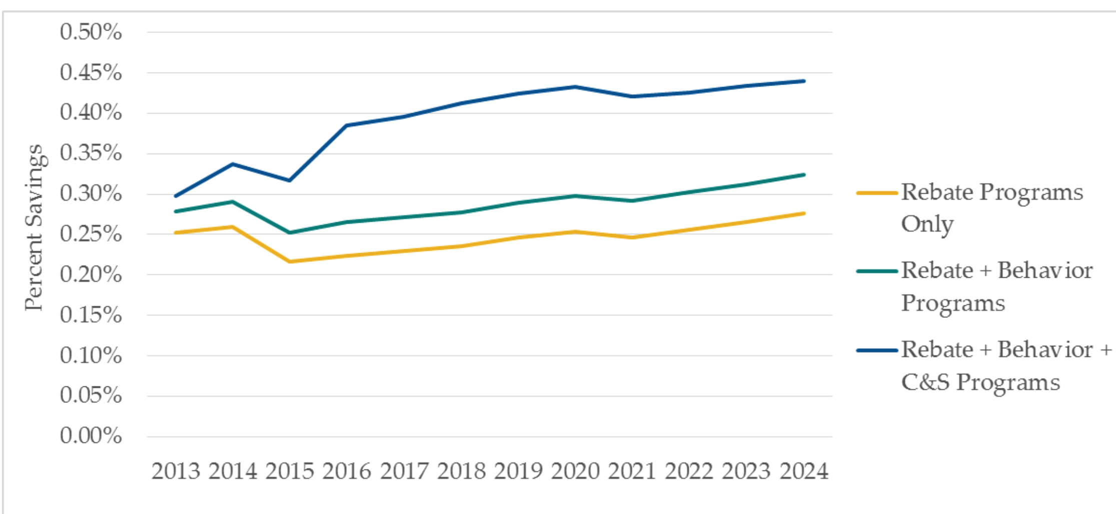
Figure 4-10 illustrates the percent savings in each year considering three sources of savings (rebate programs, behavior programs and IOU C&S programs). It is unclear at this time which sources of savings can and should be counted towards AB 1330 targets. When considering only IOU rebate programs, savings in 2016 amounts to 0.74% of sales. Adding the savings from behavior programs increases the value to 0.82%. The total savings from rebate programs, behavior programs and C&S in 2016 results in 1.58% savings. Savings as a percent of retail sales declines over time. A similar graph for gas savings can be found in Figure 4-11. In all analyzed situations, gas savings is less than 0.5% of CEC forecasted gas sales.

Figure 4-10: Statewide IOU Electric Savings as a Percent of Annual Sales



Source: June 2015 PG Results Viewer

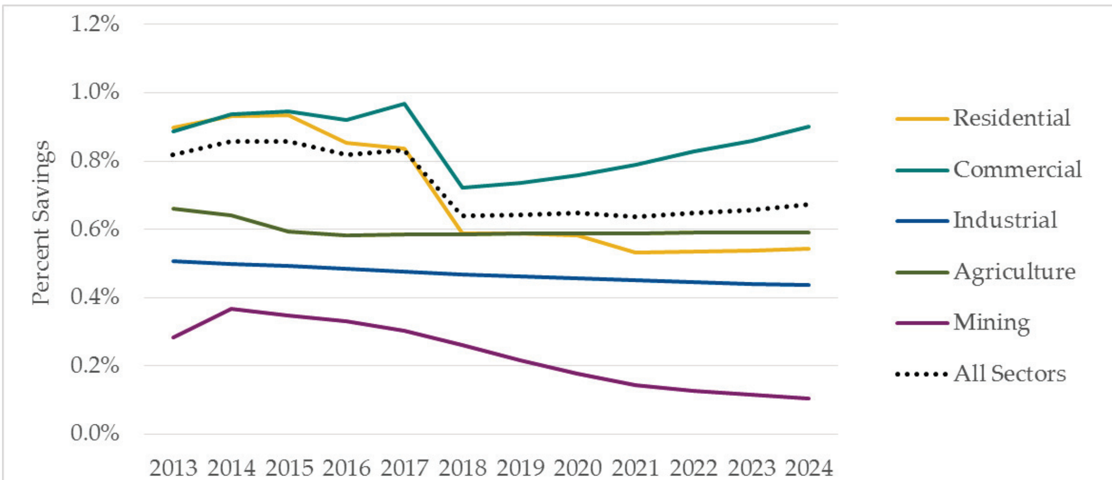
Figure 4-11: Statewide IOU Natural Gas Savings as a Percent of Annual Sales



Source: June 2015 PG Results Viewer

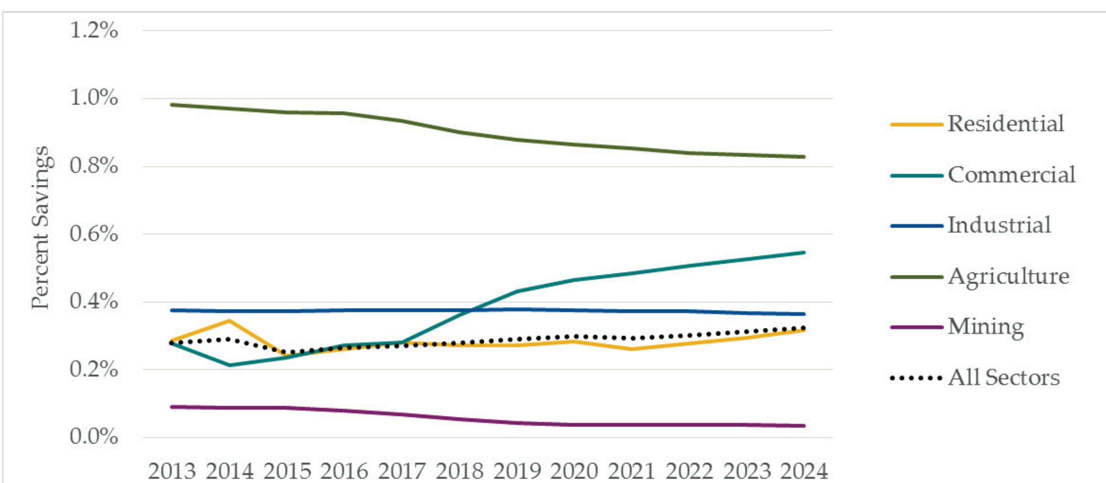
Figure 4-12 dives deeper into rebate program and behavior program savings for each sector. The graphs exclude savings from C&S. In 2016, Commercial program savings amount to 0.92% of Commercial electric sales, Residential programs result in 0.85% savings and while Industrial programs amount to 0.48% savings. The overall impact of all sectors is shown as the dotted line labeled “All Sectors”. Figure 4-13 shows a similar graphic for gas savings.

Figure 4-12: Sector Level IOU Electric Program Savings as a Percent of Annual Sales



Note: Streetlighting not shown for scale. Streetlighting averages above 2% for the entire study period.
Source: June 2015 PG Results Viewer

Figure 4-13: Sector Level IOU Gas Program Savings as a Percent of Annual Sales



Source: June 2015 PG Results Viewer

4.2 *Market Potential by IOU Territory*

The following tables (Table 4-1 through Table 4-4) detail the annual incremental market potential for each IOU from 2016 through 2024. The potential is disaggregated by rebate programs (including behavior programs) as well as net C&S (IOU claimable) savings. Savings values for PG&E and SDG&E

include interactive effects (the impact of electric energy efficiency on gas savings) while savings for SCE and SCG exclude these interactive effects. IOU rebate program potential shown in the tables below are gross incremental annual savings while the IOU claimable C&S savings are net IOU attributable annual savings. Savings values for SDG&E further reflect an adjustment to whole building savings to be consistent with CPUC Decision 14-10-046 (further discussion can be found in section 1.4).

Table 4-1: PG&E Market Potential

	GWh			MW			MMTherms		
Year	Rebate Programs*	Net C&S	Total	Rebate Programs*	Net C&S	Total	Rebate Programs*	Net C&S	Total
2016	624.5	611.3	1,235.9	85.0	140.6	225.6	12.9	5.5	18.4
2017	637.4	506.5	1,143.9	87.4	105.2	192.6	12.9	5.7	18.6
2018	507.4	408.3	915.7	68.9	103.2	172.1	14.8	6.1	20.9
2019	510.9	401.0	911.9	69.6	103.3	173.0	14.9	6.2	21.1
2020	519.1	380.9	900.0	71.4	101.3	172.7	15.5	6.2	21.7
2021	523.9	326.2	850.1	74.4	94.3	168.8	15.9	5.9	21.8
2022	541.2	294.7	835.9	80.3	89.7	170.0	16.7	5.7	22.4
2023	558.2	254.1	812.3	86.3	84.4	170.7	17.5	5.6	23.2
2024	581.3	239.8	821.1	91.7	81.5	173.3	18.6	5.3	23.9

**Includes behavior programs, excludes effects of financing.*
Source: June 2015 PG Model

Table 4-2: SCE Market Potential

	GWh			MW			MMTherms		
Year	Rebate Programs*	Net C&S	Total	Rebate Programs*	Net C&S	Total	Rebate Programs*	Net C&S	Total
2016	673.8	630.5	1,304.4	122.3	145.0	267.3	0.0	0.0	0.0
2017	693.5	522.4	1,215.9	123.0	108.5	231.4	0.0	0.0	0.0
2018	527.7	421.1	948.8	99.4	106.4	205.8	0.0	0.0	0.0
2019	541.8	413.6	955.3	103.1	106.6	209.7	0.0	0.0	0.0
2020	553.0	392.9	945.9	106.9	104.5	211.4	0.0	0.0	0.0
2021	542.4	336.5	878.9	103.3	97.3	200.6	0.0	0.0	0.0
2022	558.8	304.0	862.7	108.6	92.5	201.1	0.0	0.0	0.0
2023	573.2	262.1	835.4	113.2	87.1	200.3	0.0	0.0	0.0
2024	592.8	247.3	840.2	118.8	84.1	202.9	0.0	0.0	0.0

**Includes behavior programs, excludes effects of financing.*
Source: June 2015 PG Model

Table 4-3: SCG Market Potential

	GWh			MW			MMTherms		
Year	Rebate Programs*	Net C&S	Total	Rebate Programs*	Net C&S	Total	Rebate Programs*	Net C&S**	Total
2016	0.0	0.0	0.0	0.0	0.0	0.0	17.3	11.7	29.1
2017	0.0	0.0	0.0	0.0	0.0	0.0	18.1	12.2	30.3
2018	0.0	0.0	0.0	0.0	0.0	0.0	16.6	12.7	29.4
2019	0.0	0.0	0.0	0.0	0.0	0.0	18.0	12.6	30.6
2020	0.0	0.0	0.0	0.0	0.0	0.0	18.4	12.2	30.6
2021	0.0	0.0	0.0	0.0	0.0	0.0	17.7	10.9	28.6
2022	0.0	0.0	0.0	0.0	0.0	0.0	18.2	10.3	28.5
2023	0.0	0.0	0.0	0.0	0.0	0.0	18.6	9.6	28.2
2024	0.0	0.0	0.0	0.0	0.0	0.0	19.0	9.1	28.1

**Includes behavior programs, excludes effects of financing.*
***Excludes interactive effects*
Source: June 2015 PG Model

Table 4-4: SDG&E Market Potential

	GWh			MW			MMTherms		
Year	Rebate Programs*	Net C&S	Total	Rebate Programs*	Net C&S	Total	Rebate Programs*	Net C&S	Total
2016	181.0	143.1	324.1	24.5	32.9	57.4	2.6	0.6	3.2
2017	185.0	118.6	303.5	25.7	24.6	50.3	2.7	0.6	3.3
2018	140.8	95.6	236.4	19.6	24.1	43.7	3.2	0.7	3.9
2019	143.7	93.8	237.6	20.1	24.2	44.2	3.2	0.7	3.9
2020	147.3	89.2	236.4	20.9	23.7	44.6	3.3	0.7	4.0
2021	146.6	76.4	223.0	21.1	22.1	43.2	3.0	0.7	3.7
2022	151.3	69.0	220.3	22.5	21.0	43.4	3.1	0.6	3.7
2023	154.4	59.5	213.9	23.4	19.8	43.2	3.2	0.6	3.8
2024	158.1	56.1	214.2	24.5	19.1	43.6	3.2	0.6	3.8

**Includes behavior programs, excludes effects of financing, and includes adjustment to whole building savings to be consistent with CPUC Decision 14-10-046.*
Source: June 2015 PG Model

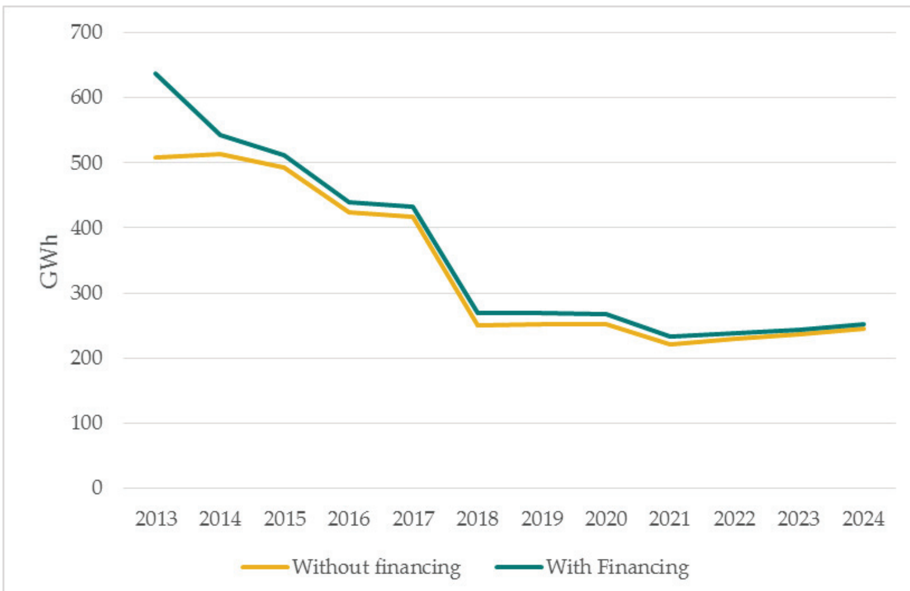
4.3 Effects of Financing on Potential

The introduction of financing reduces market barriers to energy efficiency technology adoption. To estimate the influence of financing, the PG model calculates savings potential by sector for two scenarios:

with financing and without financing. The difference between the two scenarios represents the incremental savings estimate due to energy efficiency financing.

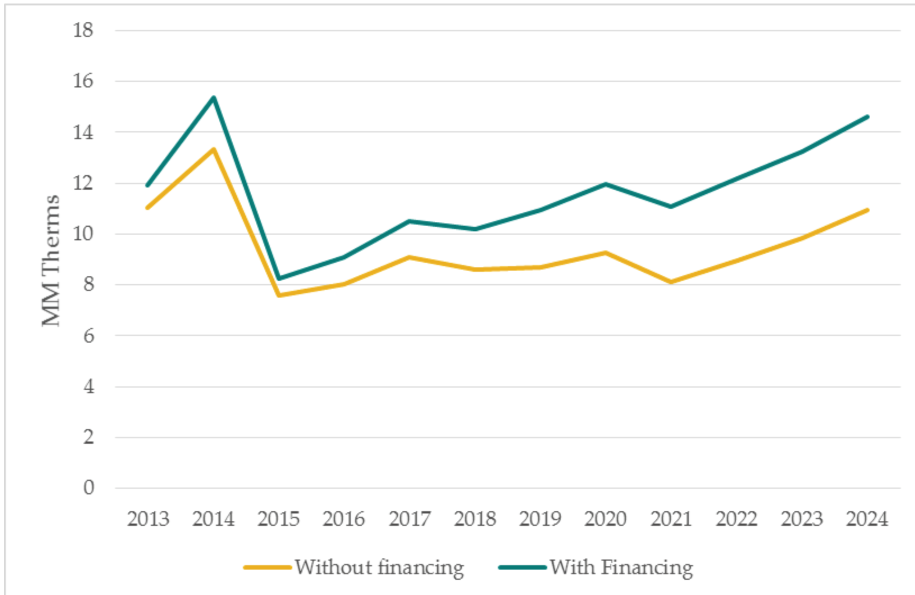
Financing increases residential sector incremental electric savings by an average of 4.5 percent (Figure 4-14) while increasing gas savings by 20.8 percent (Figure 4-15) over the 2016 -2024 time frame. The sum of all additional first year savings due to financing from 2016-2024 amounts to 117 GWh and 22 MMTherms in the residential sector. In 2016, financing adds 16.3 GWh and 1.05 MMTherms to the residential incremental savings. The impact due to financing in 2016 is equivalent to an additional 3.7% incremental first year electric savings and 11.6% incremental first year gas savings in the residential sector.

Figure 4-14: Residential Incremental Electric Savings Potential due to Financing (GWh)



Source: June 2015 PG Model

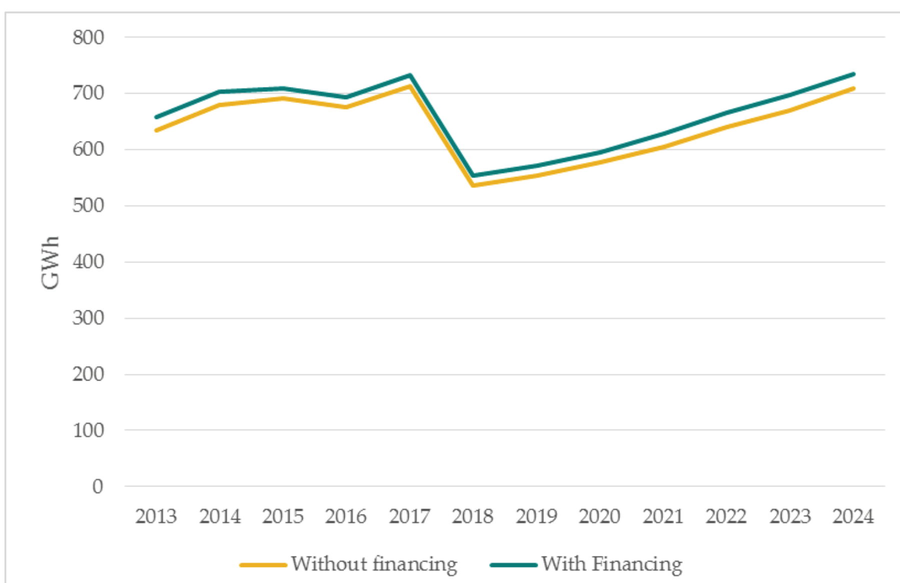
Figure 4-15: Residential Incremental Gas Savings due to Financing (MM Therms)



Source: June 2015 PG Model

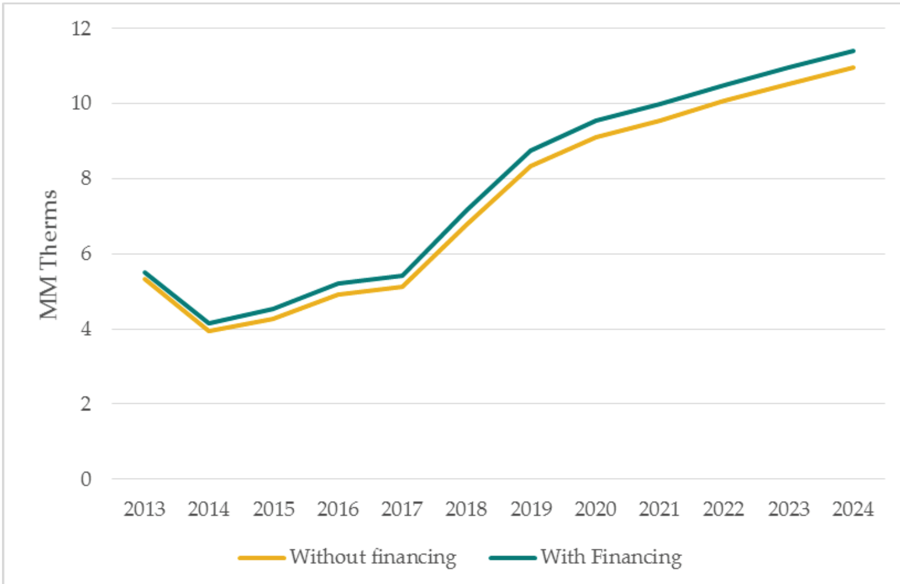
The impact of financing on the commercial sector increases electric savings by 3.3 percent (Figure 4-16) and gas savings by 4.7 percent (Figure 4-17) on average from 2016 to 2024. This translates to 193 GWh and 3.6 MM Therms of total first year electric and gas savings in the commercial sector from 2016-2024. In 2016 financing in the commercial sector can increase savings by 17.6 GWh (2.5 percent increase) and 0.3 MMTherms (5.6 percent increase).

Figure 4-16: Commercial Incremental Electric Savings due to Financing (GWh)



Source: June 2015 PG Model

Figure 4-17: Commercial Incremental Gas Savings due to Financing (MM Therms)



Source: June 2015 PG Model

Two key considerations are bounding the potential of financing in the commercial sector:

1. Population eligibility and
2. The reduction in implied discount rate assumptions.

Financing is slightly less available to commercial customers than residential customers. In the context of California energy efficiency financing landscape, the IOU energy efficiency financing pilot programs are designed to make financing accessible to the majority of residential customers. The minimum program requirement of a 580 FICO score potentially qualifies 98 percent of the residential customers. Compare to the residential sector, 77 percent of businesses have low or medium credit risk representing the eligible population for financing.

Based on Navigant's market research, residential sector customers have a much higher implied discount rate than commercial customers. Financing has a more significant reduction to residential customer implied discount rate than commercial customer implied discount rate.

4.4 Detailed Stage 1 Results

Along with the model file and the summary results shown above, the team developed a downloadable excel tool, the 2015 PG Results Viewer, which provides access to all detailed mid-case results from the model. The Results Viewer provides stakeholders the ability to manipulate and visualize model outputs from the high-level statewide standpoint all the way to the granular measure level. The Results Viewer is structured with multiple tabs to view summary results as well as detailed model outputs, as seen in Table 4-5. The results viewer can be found on the CPUC's website.[67]

Table 4-5: 2015 PG Results Viewer Tabs

Summary Outputs	Detailed Output Viewing	
Data Key	CEC Sales Data	Incremental Codes and Standards
Technical, Economic and Market Potential	Incremental Market Potential	Cumulative Codes and Standards
IOU Potential	Technical Potential	Behavior
Use Category Dashboard	Economic Potential	Incremental Market Potential Financing
Percent Savings Dashboard	Cumulative Market Potential	Cumulative Market Potential Financing
C&S and Behavior Dashboard		
Financing Dashboard		

Following is a brief description of each of the Summary Outputs tabs:

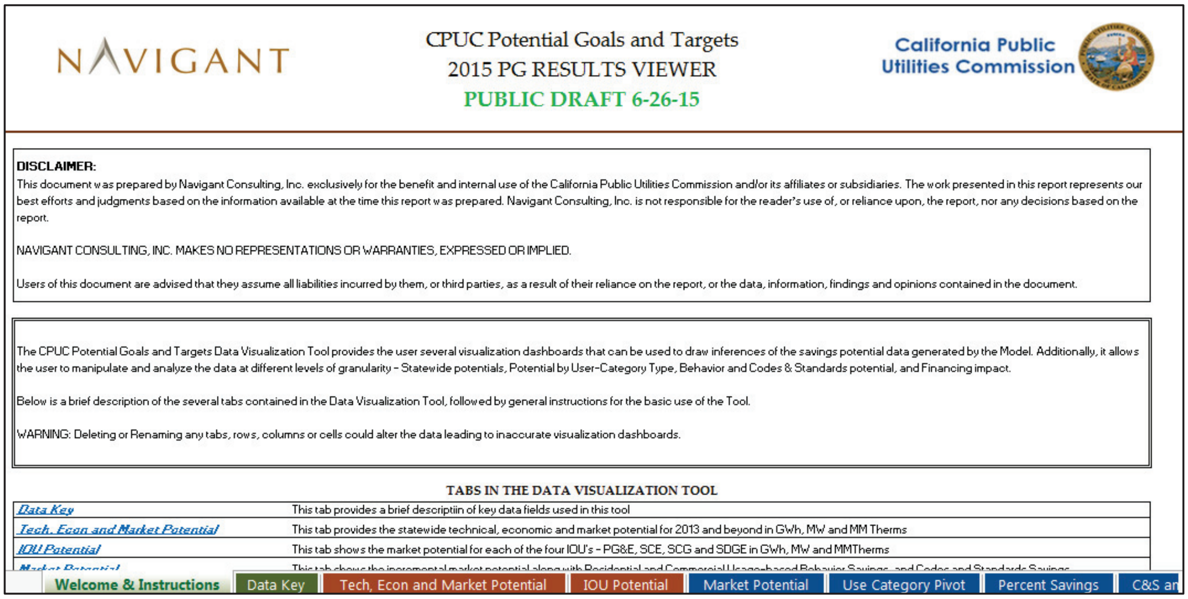
- Technical, Economic and Market Potential: This tab provides the statewide technical, economic and market potential for 2013 and beyond. The user can further filter and view results by IOU.
- IOU Potential: This tab shows the market potential for each of the four IOU's.
- Use Category Dashboard: This tab provides the user the ability to visualize the Incremental Market Potential results by End Use Categories. It also allows the user to manipulate the model outputs based on their needs through filters such as Service Territory, Building Type, Sector etc.
- Percent Savings Dashboard: This tab shows the incremental market potential as a percent of total energy sales.
- C&S and Behavior Dashboard: This tab shows the Codes and Standards, and Behavior potential for all four IOU's. It also allows the user to manipulate the model outputs based on their needs through filters such as Service Territory, Savings Type and Sector.
- Financing Dashboard: This tab shows the effects of financing on incremental market potential for Residential and Commercial sectors

On the other hand, the Detailed Output Viewing tabs contain all the raw model outputs, as well as the raw CEC Sales Data. The raw model outputs is the source data for all the dashboard visualizations provided, and additionally gives the user the ability to perform custom analysis based on their needs. Figure 4-18 through Figure 4-21 will show some snapshots of the tool.

[67] http://www.cpuc.ca.gov/PUC/energy/Energy+Efficiency/Energy+Efficiency+Goals+and+Potential+Studies.htm

Figure 4-18 is a snapshot of the Results Viewer Main Page that provides a high level summary of the tool, a brief description of each tab and some general instructions.

Figure 4-18: Results Viewer Main Page



As discussed previously, the Results Viewer provides various Summary Outputs tabs, one of which is highlighted in Figure 4-19. The layout of the results page has graphics on either side of the summary model outputs, to provide the user the ability to visually see the information, as well as seeing the model outputs that is represented in the graphs.

Figure 4-19: Tech, Econ and Market Potential Page

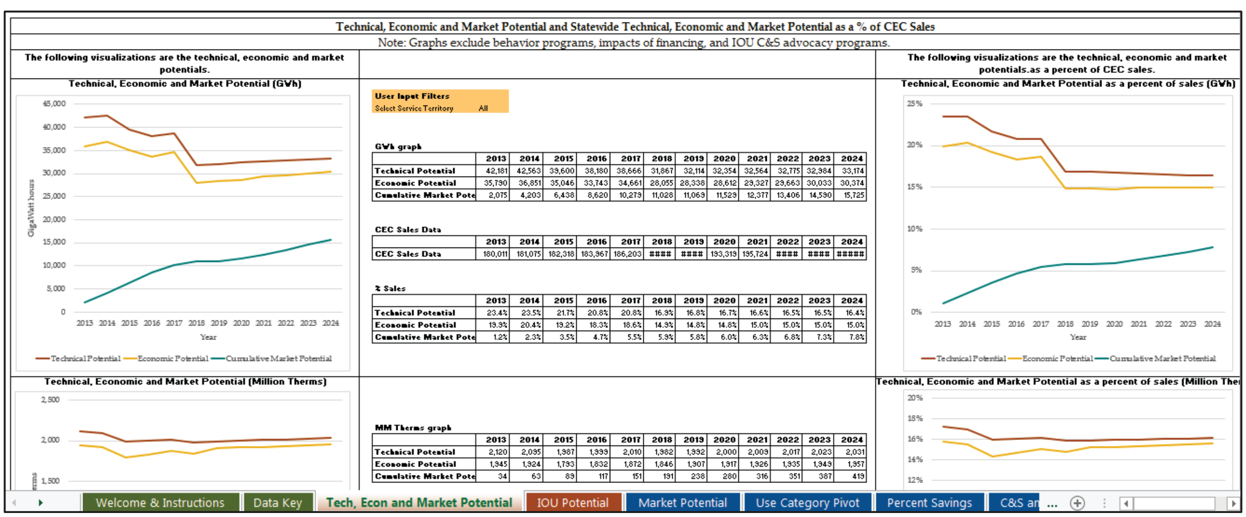
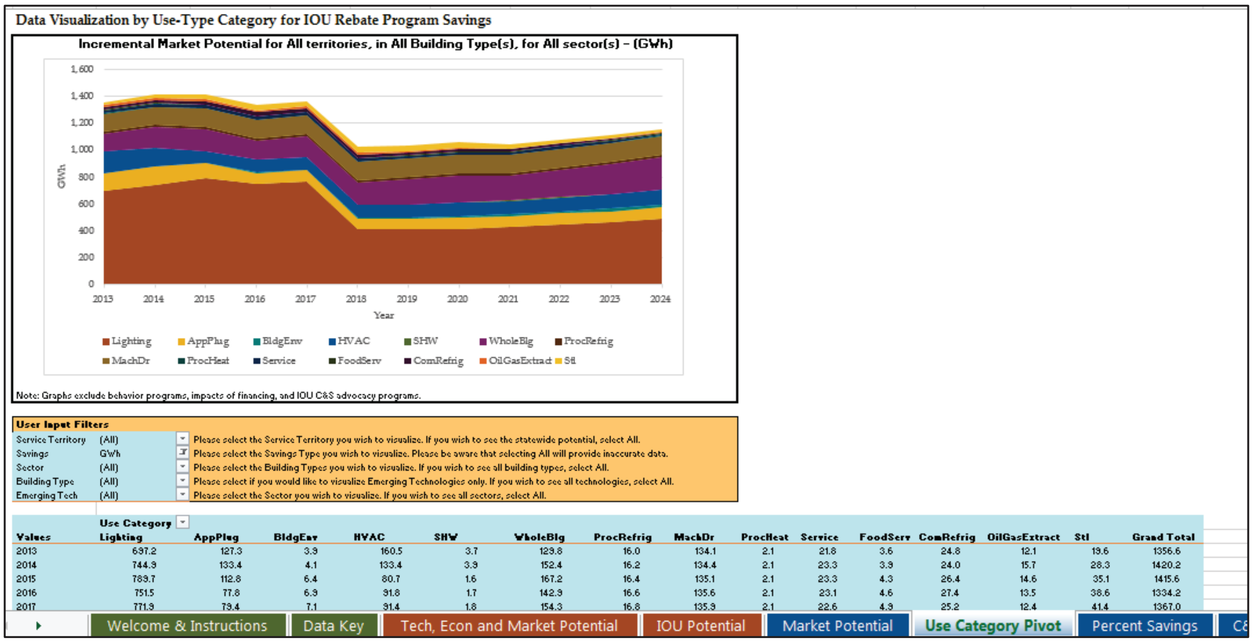


Figure 4-20 is a snapshot of the Use-Category Dashboard that gives the user over 300 different views of the results based on user defined selections of several key parameters (IOU, savings type, sector, building type, inclusion of ETs). The page layout is designed to be as simple as possible with the graphic at the top, the user-customizable filters below, followed by a table of the model outputs being plotted. The table (like the graph) is auto-updated based on the user selections.

Figure 4-20: Use-Category Dashboard Page



Values	Lighting	AppPlug	BldgEnv	HVAC	SHW	WholeBlg	ProcRefrig	MachDr	ProcHeat	Service	FoodServ	ComRefrig	OilGasExtract	Stl	Grand Total
2013	697.2	127.3	3.9	160.5	3.7	129.8	16.0	134.1	2.1	21.8	3.6	24.8	12.1	19.6	1356.6
2014	744.9	133.4	4.1	133.4	3.9	152.4	16.2	134.4	2.1	23.3	3.9	24.0	15.7	28.3	1420.2
2015	789.7	112.8	6.4	80.7	1.6	167.2	16.4	135.1	2.1	23.3	4.3	26.4	14.6	35.1	1415.6
2016	751.5	77.8	6.9	91.8	1.7	142.9	16.6	135.6	2.1	23.1	4.6	27.4	13.5	38.6	1334.2
2017	771.9	79.4	7.1	91.4	1.8	154.3	16.8	135.9	2.1	22.6	4.9	25.2	12.4	41.4	1367.0

Lastly, Figure 4-21 provides a snapshot of the detailed output format that is provided in the Results Viewer. The figure illustrates the incremental market potential. This table contains energy savings data for each measure in each IOU, building type, use category, measure type (emerging vs. conventional), sector, and year. The data resides in a format that is database-friendly and can be exported to other programs for additional user analysis.

Figure 4-21: Incremental Market Potential Page

Service Territory	Savings	Sector	Building Type	Use Category	Emerging Tech	Measure	2013	2014	2015	2016	2017	2018	2019	2020	2021	202
PG&E	GWh	Residential	Res - Multi Family	AppPlug	Yes	AppPlug - Clothes Washer (Electric) - Emerging	0.04	0.05	0.04	0.05	0.06	0.06	0.07	0.08	0.10	0.11
PG&E	GWh	Residential	Res - Multi Family	AppPlug	Yes	AppPlug - Clothes Washer (Gas) - Emerging	-0.01	-0.02	-0.01	-0.01	-0.02	-0.02	-0.02	-0.02	-0.02	-0.0
PG&E	GWh	Residential	Res - Multi Family	AppPlug	Yes	AppPlug - Dishwasher (Electric) - Emerging	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.02	0.02
PG&E	GWh	Residential	Res - Multi Family	AppPlug	Yes	AppPlug - HP Clothes Dryer - Emerging	0.00	0.00	0.00	0.00	0.06	0.13	0.21	0.31	0.41	0.5
PG&E	GWh	Residential	Res - Multi Family	AppPlug	Yes	AppPlug - Smart Strip Home Office - Emerging	0.23	0.24	0.27	0.29	0.31	0.32	0.32	0.32	0.31	0.30
PG&E	GWh	Residential	Res - Multi Family	AppPlug	Yes	AppPlug - Smart Strip Home Theater - Emerging	0.24	0.25	0.28	0.30	0.32	0.33	0.33	0.33	0.32	0.3
PG&E	GWh	Residential	Res - Multi Family	AppPlug	No	AppPlug - Clothes Washer (Electric)	0.26	0.28	0.15	0.15	0.15	0.10	0.10	0.10	0.10	0.09
PG&E	GWh	Residential	Res - Multi Family	AppPlug	No	AppPlug - Clothes Washer (Gas)	-0.38	-0.39	-0.20	-0.20	-0.20	-0.14	-0.14	-0.14	-0.14	-0.14
PG&E	GWh	Residential	Res - Multi Family	AppPlug	No	AppPlug - Computer Monitor	0.14	0.14	0.14	0.13	0.13	0.13	0.12	0.13	0.13	0.12
PG&E	GWh	Residential	Res - Multi Family	AppPlug	No	AppPlug - Desktop Computer (Res - ES Plus)	0.00	0.00	0.13	0.18	0.24	0.29	0.35	0.40	0.46	0.52
PG&E	GWh	Residential	Res - Multi Family	AppPlug	No	AppPlug - Desktop Computer (Res - ES)	0.00	0.00	0.00	0.00	0.26	0.30	0.34	0.38	0.43	0.46
PG&E	GWh	Residential	Res - Multi Family	AppPlug	No	AppPlug - Dishwasher (Electric)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PG&E	GWh	Residential	Res - Multi Family	AppPlug	No	AppPlug - Recycle Refrigerator	0.75	0.75	0.87	0.98	1.09	1.17	1.21	1.22	1.17	1.08
PG&E	GWh	Residential	Res - Multi Family	AppPlug	No	AppPlug - Self-Contained Refrigerator	0.21	0.29	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PG&E	GWh	Residential	Res - Multi Family	BldgEnv	No	BldgEnv - Attic Batt Insulation	0.17	0.16	0.15	0.14	0.13	0.11	0.09	0.08	0.06	0.05
PG&E	GWh	Residential	Res - Multi Family	BldgEnv	No	BldgEnv - Wall Spray On Insulation	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02
PG&E	GWh	Residential	Res - Multi Family	BldgEnv	No	BldgEnv - Window Film	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PG&E	GWh	Residential	Res - Multi Family	HVAC	No	HVAC - SEER Rated Split System AC (SEER 15)	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01
PG&E	GWh	Residential	Res - Multi Family	Lighting	Yes	Lighting - LED Lamp (Basic High - Indoor) - Emerging	0.00	0.00	0.01	0.01	0.02	0.01	0.02	0.03	0.06	0.10
PG&E	GWh	Residential	Res - Multi Family	Lighting	Yes	Lighting - LED Lamp (Basic High - Outdoor) - Emerging	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.02
PG&E	GWh	Residential	Res - Multi Family	Lighting	Yes	Lighting - LED Lamp (Basic Low - Indoor) - Emerging	0.01	0.02	0.05	0.09	0.15	0.04	0.07	0.11	0.16	0.2
PG&E	GWh	Residential	Res - Multi Family	Lighting	Yes	Lighting - LED Lamp (Basic Low - Outdoor) - Emerging	0.00	0.00	0.01	0.02	0.02	0.01	0.01	0.02	0.02	0.03
PG&E	GWh	Residential	Res - Multi Family	Lighting	Yes	Lighting - LED Lamp (Reflector - Indoor) - Emerging	0.00	0.02	0.03	0.06	0.10	0.14	0.17	0.20	0.23	0.25
PG&E	GWh	Residential	Res - Multi Family	Lighting	Yes	Lighting - LED Lamp (Reflector - Outdoor) - Emerging	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01
PG&E	GWh	Residential	Res - Multi Family	Lighting	Yes	Lighting - LED Lamp (Specialty - Indoor) - Emerging	0.02	0.02	0.07	0.13	0.21	0.28	0.32	0.36	0.45	0.58
PG&E	GWh	Residential	Res - Multi Family	Lighting	Yes	Lighting - LED Lamp (Specialty - Outdoor) - Emerging	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.02	0.03	0.04
PG&E	GWh	Residential	Res - Multi Family	Lighting	Yes	Lighting - LED Plug-In Indoor Fixture - Emerging	0.08	0.15	0.15	0.15	0.15	0.01	0.01	0.01	0.01	0.01
PG&E	GWh	Residential	Res - Multi Family	Lighting	Yes	Lighting - LED Plug-In Outdoor Fixture - Emerging	0.01	0.00	0.01	0.01	0.02	0.00	0.00	0.00	0.00	0.00
PG&E	GWh	Residential	Res - Multi Family	Lighting	No	Lighting - Compact Fluorescent Fixture (Indoor)	0.05	0.11	0.11	0.11	0.11	0.00	0.00	0.00	0.00	0.00
PG&E	GWh	Residential	Res - Multi Family	Lighting	No	Lighting - Compact Fluorescent Fixture (Outdoor)	0.04	0.08	0.07	0.07	0.07	0.00	0.00	0.00	0.00	0.00
PG&E	GWh	Residential	Res - Multi Family	Lighting	No	Lighting - Compact Fluorescent Lamp (Basic High - Indoor)	2.41	2.06	1.76	1.53	1.35	0.00	0.00	0.00	0.00	0.00
PG&E	GWh	Residential	Res - Multi Family	Lighting	No	Lighting - Compact Fluorescent Lamp (Basic High - Outdoor)	0.32	0.21	0.19	0.18	0.17	0.00	0.00	0.00	0.00	0.00
PG&E	GWh	Residential	Res - Multi Family	Lighting	No	Lighting - Compact Fluorescent Lamp (Basic Low - Indoor)	4.79	4.26	3.99	3.60	3.17	0.00	0.00	0.00	0.00	0.00
PG&E	GWh	Residential	Res - Multi Family	Lighting	No	Lighting - Compact Fluorescent Lamp (Basic Low - Outdoor)	0.66	0.52	0.51	0.47	0.42	0.00	0.00	0.00	0.00	0.00
PG&E	GWh	Residential	Res - Multi Family	Lighting	No	Lighting - Compact Fluorescent Lamp (Reflector - Indoor)	0.41	0.58	0.68	0.77	0.83	0.86	0.84	0.81	0.72	0.62
PG&E	GWh	Residential	Res - Multi Family	Lighting	No	Lighting - Compact Fluorescent Lamp (Reflector - Outdoor)	0.01	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02

CEC Sales Data | Incremental Market Potential | Technical Potential | Economic Potential | Cumulative Market Potential | Incremental Codes and Standards | Cumulative

A revised version of the Tool will be developed and submitted along with Stage 2 deliverables, based on stakeholder feedback and updated model outputs, including the low and high cases scenarios.

4.5 Comparison of 2015 Study to 2013 Study Results

Significant data updates have been made in Stage 1 that cause results to depart from those previously stated in the 2013 Study. A comparison of statewide (all IOUS combined) savings found in Table 4-6 through Table 4-7.

Relative to the 2013 study, overall potential from electric rebate programs decreased slightly between 2016 and 2018 while potential from C&S increased during the same period. Thus total electric potential from 2016 to 2018 increased. Rebate program electric potential after 2018 (after major changes in lighting standards take effect) decrease relative to the 2013 study.

Relative to the 2013 study, overall potential from gas rebate programs decreased on the order of 20% from 2016 through 2024. However, during this same period potential from C&S increased significantly relative to the 2013 study. The net effect of both changes is an overall minimal change to the total potential over the 2016-2024 period though a 9% increase is observed in 2016 and 2017.

The key drivers behind the differences in the results of the two studies are listed below.

» The 2015 study uses more up-to date historic market data for the purposes of model calibration. The 2015 study uses evaluated program results from 2010-12 that was not available in the 2013 study as well as better data about the saturation of equipment from saturation surveys (CLASS and CSS).

» Residential and commercial measures assumptions about unit energy savings were sourced from the DEER2015 Update and 10-12 EM&V studies. Some additional adjustments to CFLs, refrigerator recycling, and commercial lighting based on DEER2016 and the Ex Ante Uncertain Measures update.

» The 2015 study used updated measure cost data to characterize residential and commercial measures. The 2013 study in some case relied upon cost data from as early as 2008. HVAC and appliance measures saw the largest changes in cost given this data refresh.

» The CEC proved updated building stock and energy consumption forecasts.

» The updated CPUC evaluation of IOU C&S programs (2010-12 EM&V study) shows more savings than previous evaluation results (2006-08 EM&V study)

» Additional data about IOU behavior programs has generally increased behavior program savings

» Better data on LEDs was obtained. LED assumptions are more conservative in both price and efficacy in the 2015 study relative to the 2013 study. This results in a lower LED potential in the 2015 compared to the 2013 study. In the 2013, much of the increase in potential after 2018 came from LEDs. The post-2018 LED potential is more conservative given data updates.

Table 4-6: 2015 Stage 1 vs. 2013 Study Results: Electric Potential (GWh)

	2013 Study			2015 Stage 1			Difference		
Year	Rebate Programs*	Net C&S	Total	Rebate Programs*	Net C&S	Total	Rebate Programs*	Net C&S	Total
2016	1,637	937	2,574	1,482	1,385	2,867	-9%	48%	11%
2017	1,600	734	2,334	1,517	1,147	2,665	-5%	56%	14%
2018	1,227	664	1,891	1,177	925	2,102	-4%	39%	11%
2019	1,335	644	1,979	1,196	908	2,105	-10%	41%	6%
2020	1,463	613	2,076	1,219	863	2,082	-17%	41%	0%
2021	1,589	517	2,106	1,213	739	1,952	-24%	43%	-7%
2022	1,720	458	2,178	1,251	668	1,919	-27%	46%	-12%
2023	1,829	366	2,195	1,286	576	1,862	-30%	57%	-15%
2024	1,932	337	2,269	1,332	543	1,875	-31%	61%	-17%

**Includes behavior programs, excludes effects of financing.*
Source: June 2015 PG Model, and 2013 Study

Table 4-7: 2015 Stage 1 vs. 2013 Study Results: Demand Potential (MW)

	2013 Study			2015 Stage 1			Difference		
Year	Rebate Programs*	Net C&S	Total	Rebate Programs*	Net C&S	Total	Rebate Programs*	Net C&S	Total
2016	266	192	458	232	319	551	-13%	66%	20%
2017	268	127	395	236	238	475	-12%	88%	20%
2018	218	123	341	188	234	422	-14%	90%	24%
2019	238	122	360	193	234	427	-19%	92%	19%
2020	262	119	381	199	230	429	-24%	93%	13%
2021	285	109	394	199	214	413	-30%	96%	5%
2022	311	103	414	211	203	415	-32%	97%	0%
2023	335	94	429	223	191	414	-33%	103%	-3%
2024	358	90	448	235	185	420	-34%	105%	-6%

**Includes behavior programs, excludes effects of financing.*
Source: June 2015 PG Model, and 2013 Study

Table 4-8: 2015 Stage 1 vs. 2013 Study Results: Natural Gas Potential (MMTherms)

	2013 Study			2015 Stage 1			Difference		
Year	Rebate Programs*	Net C&S	Total	Rebate Programs*	Net C&S	Total	Rebate Programs*	Net C&S	Total
2016	39.2	7.3	46.5	32.8	17.9	50.6	-16%	145%	9%
2017	39.0	9.1	48.1	33.7	18.5	52.2	-13%	103%	9%
2018	43.5	10.5	54.0	34.6	19.6	54.2	-20%	87%	0%
2019	45.1	11.2	56.3	36.1	19.5	55.6	-20%	74%	-1%
2020	47.1	11.3	58.4	37.3	19.1	56.3	-21%	69%	-4%
2021	48.9	10.2	59.1	36.6	17.5	54.1	-25%	71%	-9%
2022	50.8	10.0	60.8	38.0	16.6	54.6	-25%	66%	-10%
2023	52.4	9.9	62.3	39.3	15.9	55.2	-25%	61%	-11%
2024	54.1	9.7	63.8	40.8	15.0	55.9	-25%	55%	-12%

**Includes behavior programs, excludes effects of financing.*
Source: June 2015 PG Model, and 2013 Study

Appendix A. Calibration

A.1 Overview

Forecasting is the inherently uncertain process of estimating future outcomes by applying a model to historic and current observations. As with all forecasts, the PG model results cannot be empirically validated a priori, as there is no future basis against which one can compare simulated versus actual results. Despite that all future estimates are untestable at the time they are made, forecasts can still warrant confidence when historic observations can be shown to reliably correspond with generally accepted theory and models.

Calibration provides both the forecaster and stakeholders with a degree of confidence that simulated results are reasonable and reliable. Calibration is intended to achieve three main purposes:

» Ground the model in actual market conditions and ensure the model reproduces historic program achievements;
» Ensure a realistic starting point from which future projects are made; and
» Account for varying levels of market barriers across different types of technologies and end uses.

The PG model is calibrated by reviewing portfolio data from 2006 up through 2012 to assess how the market has reacted to program offerings in the past. The Navigant team used ex-post EM&V data from 2006-2012 as the calibration data and also compared results to the 2013-2014 compliance filing data.

The calibration data are used to inform the appropriate values for the customer willingness and awareness parameters that drive measure adoption during the model time horizon. These parameters are then considered to account for the range of factors—technological, economic, market, and program factors— that contribute to historic program achievements. This includes consumers' awareness of programs and their willingness to participate in them.

This calibration method (a) tracks what measures have been installed or planned for installation over an historic six-year period and (b) forecasts how remaining stocks of equipment will be upgraded, including the influence of various factors such as new codes and standards, emerging technologies, or new delivery mechanisms. The calibration approach is not applied to emerging technologies, as there is insufficient historical basis to adjust future adoption for these technologies.

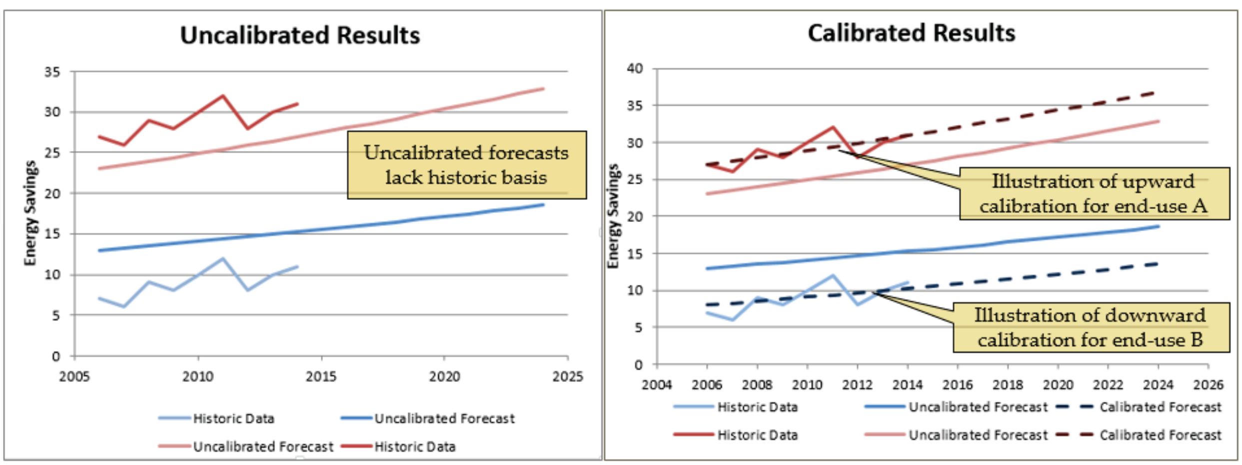
A.2 Necessity of Calibration

Calibration refers to the standard process of adjusting model parameters such that model results align with observed data. In evaluative statistical models, calibration is called *regression*, and goodness of fit is typically the main focus since the models are usually simple. In situations of complex dynamics and non-linearity (as in this study), model sophistication and adequacy can become the main focus. But grounding the model in observation remains equally necessary. The ability of a forecast to reasonably simulate observed data affords credibility and confidence to forecast estimates.

Although there are data supporting all underlying parameters in the PG model, much of the data are at an aggregate level that can be inadequate to forecast differences across the various classes of technologies and end uses. The customer willingness-to-adopt factor is a good example of this effect. Customers may exhibit certain average purchase tendencies in adopting measures based on their financial characteristics. However there may be features of certain end use technologies that cause customer behavior to vary from the average. Residential building envelope is an end use where adoption of measures like insulation is consistently lower than would be predicted compared with other end uses. Residential lighting adoption, on the other hand, performs better than the average predicted customer purchase tendencies, even after adjusting for differences in financial attractiveness. We often think of these differences as the influence of non-financial product attributes or of market barriers.

Figure A-1 below illustrates the concept of calibration. The chart on the left shows how certain end uses may over predict (blue) or under predict (red) adoption compared to observations of program participation. By adjusting the customer willingness factors, as illustrated in the right chart below, the modeled results in past years become aligned with reported historical program achievements.

Figure A-1: The Concept of Calibrating



Note that model parameters and results may be increased *or* decreased depending on the end use. We do not "calibrate down" on aggregate, but rather just "calibrate" the end uses both up and down as appropriate based on the data, as shown in the chart on the right above.

Calibration is not an optional exercise in modeling. One might suggest that the average customer data should be sufficient to make a reliable aggregated forecast. However there are two important non-linearities that compel us toward a more granular parameterization:

» Program portfolios are not evenly composed across end-uses. This leads to an uneven weighting issue whereby average customer willingness may not lead to the correct calculation of total savings.

» The dynamics in the model regarding the timing of adoption can become incompatible with the remaining potential indicated by program achievements. For example, if the forecast results were not calibrated for CFL lighting in the residential sector, the saturation may remain inaccurately low in early years and indicate a larger remaining potential in future years. Thus calibrating a willingness parameter upward may increase its potential in the early years but decrease its potential in later years. This implies that in the absence of IOU program intervention, residential CFLs would have historically had much lower adoption. Calibration therefore allows us to capture these program influences to more accurately reflect remaining potential.

This discussion is intended to highlight the necessity of calibration and the effective irrelevance of uncalibrated parameters. It may be tempting to "relax" the calibrated parameters back toward the average to measure the effect of what could be possible. But the uncalibrated results can be difficult to interpret and almost certainly would not produce feasible results for certain end uses. Thus they provide no basis for a reasonable forecast. Instead, we treat the calibrated results as the most basic set of interpretable results from which alternate scenarios are developed. Changes to calibrated parameters are not returned to the uncalibrated averages, but are rather explicitly developed based on the feasibility of values that parameters might take over time and how quickly the change might occur. This is discussed more in the last section of this brief.

A.3 Interpreting Calibration

Calibration can constrain market potential for certain end uses when aligning model results with past IOU energy efficiency portfolio accomplishments. Although calibration provides a reasonable historic basis for estimating future market potential, past program achievements may not capture the potential due to structural changes in future programs or changes in consumer values. Calibration can be viewed as holding constant certain factors that might otherwise change future program potential, such as:

» Consumer values and attitudes toward energy efficient measures;
» Market barriers associated with different end uses;
» Program efficacy in delivering measures; and
» Program spending constraints and priorities.

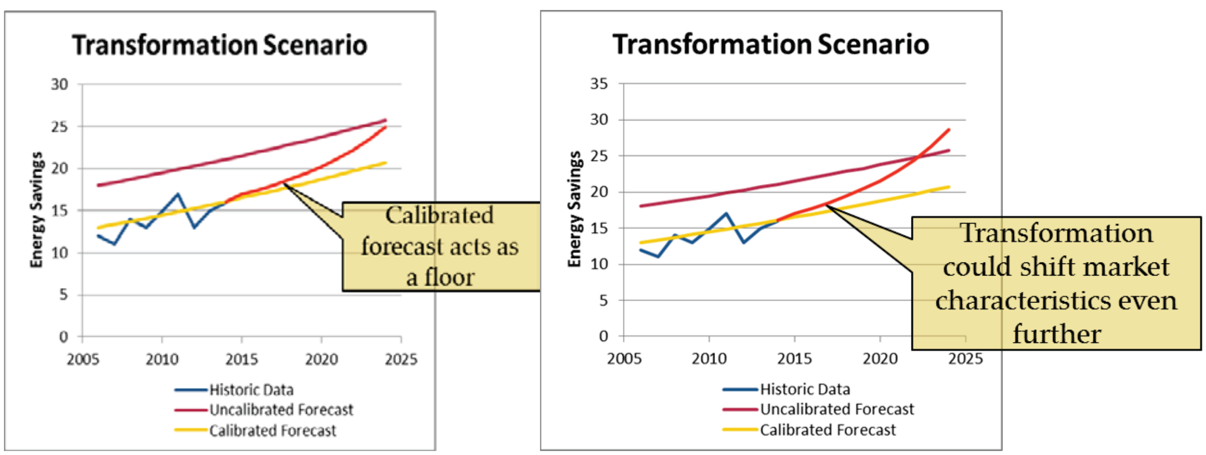
Changing values and shifting program characteristics would likely cause deviations from market potential estimates calibrated to past program achievements.

Does calibrating to historic data constrain the future forecast? In a strictly numeric sense, yes. If a certain end use is calibrated downward or upward, then future adoption and its timing are affected. However this should not be interpreted as "calibration constrains the level of adoption that we think is possible." Rather calibration provides a more accurate estimate of the current state of customer willingness, market barriers, program characteristics and remaining adoption potential. One forecast scenario might assume that the underlying conditions remain the same—a sort of business as usual scenario. We might develop another scenario such that it represents a transforming market based on agreed-upon end state parameter values appropriate for the end use market. For insulation that may mean a slight improvement, for water heating a greater improvement, and for lighting perhaps little change is warranted if fewer market barriers exist today.

One interpretation is that the calibration process creates a floor for the remaining potential. Market barriers, customer attitudes, and program efficacy generally move in the direction of improvement. The extent to which a market or program can improve should not be compared to the uncalibrated results, but rather to the vision for what is reasonably possible for the paramters describing each end use. This may require little change, some change, or greater change in parameter values for different end-uses. But improvements to parameter values are based on their own merits and feasibility, and are independent of the uncalibrated paramter values and results.

Figure A-2 below shows two illustrative end uses where there is a calibrated base scenario (yellow) and alternative high scenarios (red) that are independent of the uncalibrated numbers (dark red). The chart on the left below shows a high forecast that may increase but still not meet the uncalibrated forecast, while the chart on the right shows a high forecast that exceeds the adoption of the uncalibrated forecast. The relation to the uncalibrated forecast is effectively arbitrary.

Figure A-2: Illustrative Transformative Scenarios



A.4 Implementing Calibration

Calibration examines three types of parameters to best align results with past program achievements:

» *Willingness parameters*
  - Primary target of calibration,
  - *Implied Discount Rate* – the iDR is adjusted when perceived market barriers are higher or lower than typical measures, or when factors other than financial characteristics may play a larger role in purchase decisions,
  - *Sensitivity* – the consumer sensitivity to the differences in financial attractiveness is adjusted when markets are considered mature and customer primary focus is measure financial attractiveness.

- *Awareness parameters*
    - Sometimes used, but only after willingness,
    - Results are generally insensitive to awareness factors when measures are replace on burnout (ROB) with a measure life greater than 5 years because stock turnover dominates the timing,
    - *Word of mouth and marketing factors* - For retrofit and short-lived measures awareness can be adjusted to better fit the timing of market growth.
- *Initial awareness*
    - Less influential, but frequently used to align the curvature of the adoption with 2013 market saturation data.
    - Used to align the curvature of adoption timing with the estimated willingness and starting saturations.

Parameters are adjusted to fit historic observations during the calibration period. Then the parameters are applied to the forecast period, which begins in the year of most recent density data vintage. Calibrating parameters up and down can have different effects in a dynamic model depending on the initial saturation (i.e., density) data. For example, calibrating up can increase both historic and future adoption if the initial saturation is low. If initial saturation is high, then calibrating up can increase past adoption in the model, leaving less for future years.

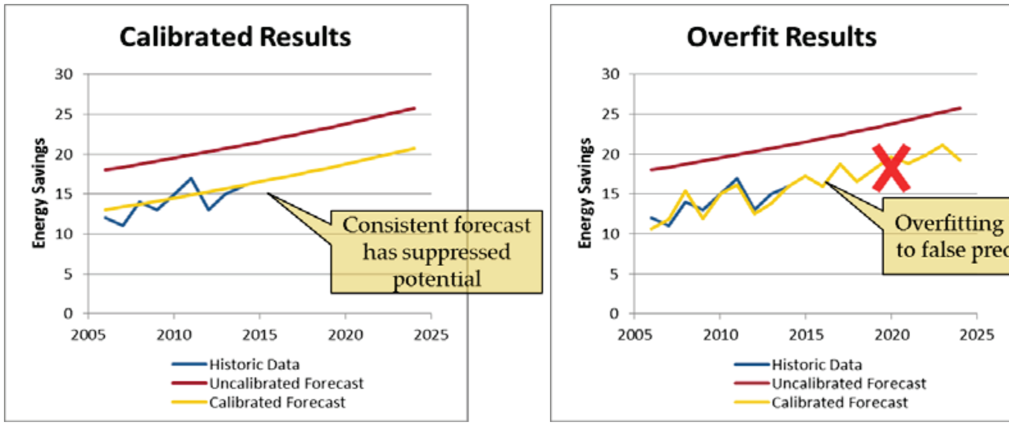
Once the consumer preference parameters are calibrated, the model forecast begins in 2013 by applying known market saturation data of that same vintage. Forecasts indicate the saturation of measures over time under the expected IOU future program influences.

A.5 Granularity of Calibration

The calibration process is undertaken at the sector and end use level for program activity in years 2006 to 2012.[68] The calibration accordingly accounts for the *cumulative* effect of market and program activity during these years. In our experience, this level is sufficient to capture the major differences in customer attitudes at the sector and end use level and to produce stable, reliable results over the forecast period. Overfitting the data (as illustrated in Figure A-3) can produce erratic model behavior that is beyond the precision of the forecast and the data that we use.

[68] Evaluation ex-post gross data were used for 2006-2012 from the CA Standard Program Tracking Database

Figure A-3: Proper and Improper Calibration



The data used for calibration are the ex post, gross evaluated program data. These data have units of energy savings such as MWh and Therms saved. By adjusting consumer preference parameters we can align the adoption and savings forecast over the calibration period with the actual evaluation data. This alignment is used by adjusting the consumer parameters for each sector, utility, and end use. The model is not calibrated at the building type or measure level for three reasons:

- The gain in precision of the results from calibrating at a lower level is expected to be negligible owing to the precision of the data sources for non-calibrated model inputs (e.g., density, building stocks, and calibration data).
- Calibrating at the lowest level of the model may give an appearance of rigor. But it is unlikely that customer preferences are represented by such sophisticated and highly dimensional reasoning. In other words, a highly granular model of consumer preferences would be at odds with the relative simplicity of the reasoning that consumers apply when making a purchase decision.
- Optimizing the non-linear model at the measure and building type level is a computationally intractable task that would require division into many batches—an enormously work- and time-intensive task due to the complexity of the model. It is not clear that such a path would lead to more accurate results and indeed might take away valuable resources from completing other aspects of the study scope.

The end use/sector/multiyear level of calibration was chosen because:

- The model variance is mostly explained at the sector and end use level making this level adequate to account for the most influential non-linear effects,
- The precision of lower level calibration results is not significantly improved beyond the chosen level,
- It is unlikely that in deciding to adopt a measure, consumers show very different purchase behavior toward similar technologies,
- Individual year calibration data are too noisy and inconsistent to fit and may lead to unreliable predictions.
- The chosen level of calibration strikes the right balance of analytical benefit versus cost.

Calibration of the PG model is performed at the back end of the modeling process in that input willingness and awareness parameters are iteratively (and manually) adjusted in the back end of the model until alignment is reached with ex post, gross evaluated data program data over the calibration period. The manual nature of this iterative task results in a lengthy process that requires repeatedly running the model, one sector and IOU at a time, to calibrate at the end-use level.

A.6 Scenario Analyses

This section offers an auxiliary discussion about scenario analyses not directly related to the process of calibration but brought up by stakeholders in relation to discussions about calibration.

Explicit Scenarios

Calibrated parameters provide the starting point for interpretable quantitative results. Scenarios are developed as explicit modifications to key variables the calibrated forecast such that the results can be easily interpreted. Multiple key variables can be changed in the calibrated forecast to produce results under different scenarios. These key variables fall under two categories:

1. Exogenous variables (events and outcomes that cannot be influenced) and
2. Endogenous variables (events and outcomes that can be influenced)

Disentanglement of Parameter Uncertainty from Policy and Program Levers in Scenarios

One factor that has obfuscated the interpretation of scenarios in the 2013 study is the combination of exogenous parameter uncertainty (e.g., retail rates, building stocks, technology curves, etc.) with the endogenous variables that may be influenced by policy and program implementation (e.g., measure inclusion criteria, codes and standards, variable incentive levels, or market transformation activities). This conflation of exogenous and controllable parameters within the scenarios made them difficult to interpret. Separation of exogenous parameter uncertainty from parameters that may be influenced or controlled will help disambiguate the meaning of the scenarios.

Navigant believes it is important to consider the effects of exogenous parameter estimates as a statement about the range of uncertainty stemming from several important factors that are beyond stakeholder's control--an effective uncertainty band. Then other parameters that represent the influence of policy and program decisions might be used to estimate credible increases in adoption, beyond the base calibrated results that might be achieved.

Maximum Achievable Potential

In previous discussions, some stakeholders have expressed a desire to use estimates of economic potential to convey the upper bound of what is possible. Although economic potential has a financial basis, it does not have a market basis. In particular, economic potential has no consideration of customer preferences nor does it account for the turnover of stock and the time scale of diffusion for different classes of technologies. For instance, future potential for ROB and long-lived measures generally are constrained by stock turnover rates which is not captured within economic potential. This leaves a disconnect and a gap between economic potential and the upper bound of what could maximally be achieved with market-based program activities under idealized market conditions. Furthermore, the *maximum achievable potential (MAP)* is not a result that would likely be achieved under current conditions, but rather provides a maximum benchmark against which future market and program potential can be interpreted. The idea of MAP is one that would not penalize future potential based on current conditions, but rather show that programs will include strategies that might remove barriers over time which could lead to higher market adoption rates. In essence, such a scenario would illustrate future shifts in programmatic priorities and consumer attitudes that would increase future savings. Navigant will develop details for the MAP scenario as part of Stage 2 work.

A.7 Detailed Electric Calibration Inputs

Table A-1: PG&E Electric Detailed Calibration Inputs by Sector, End-Use, and Year (GWh)

Sector End-Use	2006	2007	2008	2009	2010	2011	2012	2006-2012 Total
Residential	**206.86**	**504.21**	**722.23**	**434.65**	**683.82**	**527.95**	**454.80**	**3,534.52**
AppPlug	36.98	72.15	82.92	48.71	98.58	83.59	57.38	480.32
BldgEnv	0.46	1.02	1.26	1.10	3.66	3.21	2.95	13.66
HVAC	2.43	3.95	4.35	3.50	7.69	3.95	4.45	30.31
Lighting	166.80	426.30	630.77	379.50	571.94	435.16	387.09	2,997.57
NA	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SHW	0.15	0.43	0.22	0.09	0.23	0.39	0.07	1.59
WholeBlg	0.04	0.35	2.71	1.75	1.73	1.65	2.85	11.08
Commercial	**154.43**	**438.66**	**852.94**	**580.03**	**391.68**	**367.34**	**389.16**	**3,174.24**
AppPlug	1.38	5.75	32.57	24.11	21.04	23.78	18.26	126.89
BldgEnv	2.49	4.61	6.05	2.20	1.70	1.58	1.38	20.00
ComRefrig	20.16	62.67	99.40	69.57	64.27	64.32	53.43	433.82
FoodServ	0.28	6.84	3.96	3.59	3.42	1.79	0.88	20.76
HVAC	17.20	57.54	138.37	105.52	86.83	80.46	79.22	565.15
Lighting	110.71	289.30	524.43	360.55	171.56	182.40	224.61	1,863.56
NA	1.54	11.91	47.43	12.80	5.49	3.45	2.01	84.63
ProcHeat	0.00	0.00	0.15	0.04	0.11	1.01	2.75	4.06
ProcRefrig	0.00	0.00	0.00	0.00	21.34	8.50	6.32	36.16
Service	0.00	0.00	0.00	1.63	15.81	0.00	0.00	17.44
SHW	0.68	0.04	0.58	0.03	0.11	0.04	0.29	1.77
Res/Com Total	**361.29**	**942.87**	**1,575.17**	**1,014.67**	**1075.49**	**895.29**	**843.96**	**6,708.76**

Source: Navigant analysis of CPUC Standard Program Tracking Database. 2014 (includes HVAC Interactive Effects)

Table A-2: SCE Electric Detailed Calibration Inputs by Sector, End-Use, and Year (GWh)

Sector End-Use	2006	2007	2008	2009	2010	2011	2012	2006-2012 Total
Residential	**271.56**	**529.85**	**549.91**	**465.04**	**843.33**	**727.05**	**742.00**	**4,128.74**
AppPlug	81.91	80.36	110.37	85.69	96.87	73.01	39.20	567.41
BldgEnv	0.01	0.21	0.41	2.04	1.40	0.78	0.06	4.91
HVAC	2.19	6.02	6.86	4.34	3.79	2.35	4.31	29.86
Lighting	184.23	434.59	386.58	366.20	722.98	641.98	668.97	3,405.53
Service	3.19	8.46	44.43	6.62	17.67	7.84	28.73	116.94
SHW	0.03	0.20	0.34	0.14	0.61	0.82	0.17	2.32
WholeBlg	0.00	0.00	0.93	0.00	0.00	0.29	0.56	1.77
Commercial	**189.77**	**439.21**	**523.16**	**441.39**	**424.67**	**424.77**	**382.07**	**2,825.04**
AppPlug	0.97	1.83	13.49	16.21	17.87	10.33	14.05	74.74
BldgEnv	1.18	1.72	2.25	0.84	4.37	7.71	3.04	21.11
CompAir	0.00	0.00	0.00	0.00	0.00	0.00	0.30	0.30
ComRefrig	14.49	16.57	30.34	18.77	39.45	58.97	36.55	215.13
FoodServ	0.15	10.64	1.42	3.98	2.23	1.90	1.66	21.98
HVAC	17.37	49.12	107.46	63.25	57.18	62.14	68.35	424.87
Lighting	135.48	309.60	337.20	292.93	268.28	263.22	231.44	1,838.14
NA	0.01	2.56	5.59	10.66	17.70	8.18	8.16	52.86
ProcHeat	0.00	0.21	0.23	0.00	0.00	0.00	0.15	0.59
ProcRefrig	0.00	0.00	0.00	0.00	0.60	1.12	3.51	5.23
Service	0.17	8.39	17.05	2.08	1.83	1.06	5.19	35.79
SHW	0.10	0.04	0.00	0.00	0.00	0.00	0.00	0.14
WholeBlg	19.86	38.54	8.14	32.66	15.15	10.15	9.68	134.18
Res/Com Total	**461.33**	**969.06**	**1,073.07**	**906.44**	**1,268.00**	**1,151.82**	**1,124.07**	**6,953.79**

Source: Navigant analysis of CPUC Standard Program Tracking Database. 2014 (includes HVAC Interactive Effects)

Table A-3: SDG&E Electric Detailed Calibration Inputs by Sector, End-Use, and Year (GWh)

Sector End-Use	2006	2007	2008	2009	2010	2011	2012	2006-2012 Total
Residential	**55.38**	**177.31**	**120.23**	**142.49**	**136.62**	**189.18**	**243.31**	**1,064.52**
AppPlug	8.69	18.88	16.74	17.40	14.22	9.21	7.29	92.42
BldgEnv	0.10	0.18	0.25	0.24	0.16	0.14	0.18	1.26
HVAC	0.10	1.46	1.58	3.87	1.26	2.29	1.49	12.05
Lighting	46.47	156.77	97.68	106.50	119.40	176.94	233.92	937.67
NA	0.00	0.00	0.00	0.00	0.00	0.36	0.20	0.55
SHW	0.01	0.03	3.98	10.15	0.01	0.01	0.10	14.29
WholeBlg	0.00	0.00	0.00	4.32	1.58	0.24	0.13	6.27
Commercial	**72.80**	**135.75**	**188.65**	**294.72**	**87.11**	**82.27**	**131.21**	**992.50**
AppPlug	0.56	1.42	5.88	6.05	4.96	0.47	7.41	26.76
BldgEnv	0.14	1.02	0.61	0.52	0.89	0.20	0.27	3.64
ComRefrig	4.00	5.27	8.21	9.64	11.42	10.97	12.25	61.76
FoodServ	0.03	3.22	0.18	2.07	0.23	0.99	0.84	7.55
HVAC	6.85	45.45	45.10	46.07	23.59	26.18	36.51	229.76
Lighting	54.60	72.14	121.82	183.73	38.80	34.93	57.11	563.13
NA	0.92	4.09	5.63	30.08	5.45	7.66	10.67	64.50
ProcHeat	0.00	0.00	0.00	0.00	0.00	0.04	0.00	0.04
Service	0.00	0.78	0.29	4.00	1.61	0.80	6.04	13.52
SHW	0.00	0.08	0.88	1.77	0.09	0.02	0.11	2.93
WholeBlg	5.70	2.28	0.07	10.79	0.07	0.00	0.00	18.90
Res/Com Total	**128.18**	**313.06**	**308.88**	**437.20**	**223.73**	**271.45**	**374.52**	**2,057.02**

Source: Navigant analysis of CPUC Standard Program Tracking Database. 2014 (includes HVAC Interactive Effects)

A.8 Detailed Gas Calibration Inputs

Table A-4: PG&E Gas Detailed Calibration Inputs by Sector, End-Use, and Year (MM Therms)

Sector End-Use	2006	2007	2008	2009	2010	2011	2012	2006-2012 Total
Residential	**-2.81**	**-7.45**	**-9.60**	**-5.67**	**-8.45**	**-6.44**	**-5.87**	**-46.30**
AppPlug	-0.52	-0.93	-0.58	0.44	0.27	0.20	0.18	-0.94
BldgEnv	0.27	0.41	0.52	0.36	1.12	1.04	0.92	4.64
HVAC	0.45	0.68	1.04	0.72	1.04	0.59	0.38	4.89
Lighting	-3.20	-8.12	-11.57	-8.18	-12.41	-9.75	-8.72	-61.95
NA	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SHW	0.18	0.48	0.61	0.66	1.14	1.16	0.73	4.95
WholeBlg	0.00	0.04	0.39	0.34	0.39	0.32	0.64	2.11
Commercial	**1.68**	**6.95**	**17.35**	**5.06**	**4.12**	**5.59**	**4.30**	**45.06**
AppPlug	0.03	0.07	0.16	0.13	0.00	-0.01	0.02	0.40
BldgEnv	0.00	0.01	0.02	0.01	0.65	0.28	0.24	1.20
ComRefrig	0.13	0.41	0.02	0.02	0.01	0.02	0.22	0.82
FoodServ	0.08	0.15	0.45	0.22	0.11	0.19	0.30	1.50
HVAC	1.70	7.36	15.52	6.25	1.44	1.91	2.99	37.18
Lighting	-0.80	-1.96	-3.20	-3.44	-1.26	-1.16	-1.63	-13.45
NA	0.03	0.02	1.42	0.14	0.69	2.59	0.40	5.30
ProcHeat	0.19	0.62	1.89	0.98	1.05	0.57	0.76	6.06
ProcRefrig	0.00	0.00	0.00	0.00	0.07	0.02	0.01	0.10
Service	0.00	0.00	0.00	0.00	0.87	0.00	0.00	0.87
SHW	0.32	0.29	1.06	0.75	0.50	1.18	0.98	5.08
Res/Com Total	**-1.13**	**-0.50**	**7.74**	**-0.61**	**-4.33**	**-0.86**	**-1.57**	**-1.24**

Source: Navigant analysis of CPUC Standard Program Tracking Database. 2014 (includes HVAC Interactive Effects)

Table A-5: SCG Gas Detailed Calibration Inputs by Sector, End-Use, and Year (MM Therms)

Sector End-Use	2006	2007	2008	2009	2010	2011	2012	2006-2012 Total
Residential	**1.19**	**1.67**	**2.36**	**4.12**	**8.52**	**8.43**	**7.48**	**33.79**
AppPlug	0.17	0.34	0.48	0.41	0.99	0.77	1.72	4.88
BldgEnv	0.19	0.38	0.35	0.26	0.34	0.33	0.36	2.22
HVAC	0.05	0.16	0.08	0.10	0.73	0.84	0.77	2.73
NA	0.00	0.00	0.00	0.12	0.25	1.32	1.18	2.87
SHW	0.79	0.79	1.44	3.13	6.12	5.14	3.24	20.66
WholeBlg	0.00	0.00	0.00	0.10	0.09	0.04	0.20	0.43
Commercial	**6.22**	**13.69**	**28.71**	**20.09**	**4.86**	**9.87**	**15.08**	**98.52**
AppPlug	0.00	0.00	0.47	0.69	0.34	0.23	0.00	1.75
BldgEnv	0.58	0.50	0.46	0.21	0.13	0.03	0.01	1.93
FoodServ	0.05	0.18	0.33	0.54	0.33	0.23	0.29	1.96
HVAC	3.64	8.51	14.38	14.67	0.77	0.58	3.16	45.71
NA	1.53	1.96	9.95	1.09	1.57	1.64	5.18	22.91
ProcHeat	0.25	0.85	0.92	0.33	0.57	1.80	5.02	9.74
ProcRefrig	0.00	0.00	0.00	0.00	0.07	0.01	0.03	0.11
SHW	0.16	1.69	2.20	0.76	0.54	0.59	0.43	6.38
WholeBlg	0.01	0.00	0.00	1.78	0.52	4.75	0.96	8.03
Res/Com Total	**7.41**	**15.36**	**31.07**	**24.21**	**13.38**	**18.31**	**22.56**	**132.31**

Source: Navigant analysis of CPUC Standard Program Tracking Database. 2014

Table A-6: SDG&E Gas Detailed Calibration Inputs by Sector, End-Use, and Year (MM Therms)

Sector End-Use	2006	2007	2008	2009	2010	2011	2012	2006-2012 Total
Residential	**-0.46**	**-1.55**	**0.40**	**2.12**	**0.59**	**-0.40**	**-2.22**	**-1.52**
AppPlug	-0.12	-0.08	0.82	0.16	0.00	0.20	0.09	1.07
BldgEnv	0.03	0.06	0.07	0.07	0.05	0.05	0.06	0.39
HVAC	0.01	0.05	0.06	0.13	0.17	0.18	0.13	0.74
Lighting	-0.59	-2.03	-1.16	-1.11	-1.45	-2.19	-2.94	-11.47
NA	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SHW	0.20	0.45	0.61	2.86	1.71	1.31	0.42	7.57
WholeBlg	0.00	0.00	0.00	0.01	0.11	0.04	0.02	0.18
Commercial	**1.11**	**0.84**	**1.34**	**3.61**	**0.85**	**1.68**	**4.49**	**13.91**
AppPlug	0.03	0.06	0.05	0.00	-0.06	0.01	0.00	0.09
BldgEnv	0.00	0.00	0.01	0.00	0.09	0.08	0.00	0.18
ComRefrig	0.03	0.03	0.05	0.07	0.04	0.05	0.09	0.37
FoodServ	0.02	0.05	0.05	0.05	0.05	0.09	0.08	0.38
HVAC	0.17	0.56	0.76	1.91	0.31	0.10	1.41	5.22
Lighting	-0.12	-0.17	-0.25	-0.32	-0.04	-0.05	-0.11	-1.06
NA	0.03	0.11	0.17	0.52	0.19	0.93	2.52	4.48
ProcHeat	0.84	0.01	0.00	0.16	0.09	0.22	0.21	1.51
ProcRefrig	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Service	0.00	0.00	0.00	0.00	0.04	0.00	0.11	0.15
SHW	0.02	0.19	0.49	1.18	0.14	0.25	0.19	2.47
WholeBlg	0.10	-0.01	0.00	0.03	0.00	0.00	0.00	0.13
Res/Com Total	**0.65**	**-0.71**	**1.75**	**5.73**	**1.44**	**1.28**	**2.27**	**12.39**

Source: Navigant analysis of CPUC Standard Program Tracking Database. 2014 (includes HVAC Interactive Effects)

Appendix B. Emerging Technologies

The Stage 1 update for Emerging Technologies (ETs) maintained the same measure list as the 2013 Study and focused on only updating the inputs to the 2015 PG Model where the Navigant team had better information or data availability.

ETs are defined as meeting one or more of the following criteria:

» Not widely available in today's market but expected to be available in the next 1-3 years;

» Widely available but representing less than 5% of the existing market share; and/or

» Costs and/or performance are expected to improve in the future.

B.1 Overview of Updates

ETs were only examined for the Residential and Commercial sectors. These sectors are modeled using individual measures for specific applications.

The Navigant team relied on data from various sources to update each ET:

» The Navigant team extrapolated or used directly cost and performance data from DEER where possible. In some cases, some ETs had already been characterized in the DEER database since the 2013 Study. For such cases, the Navigant team continued to call these measures ETs to be consistent with the last study (e.g. 0.98 AFUE Gas Furnace).

» IOU workpapers and other case studies provided additional cost and performance data.

» 2010 – 2012 EM&V studies[69] such as "Work Order 017 Ex Ante Measure Cost Study "provided more California-specific data.

» In absence of any California-specific verified data, the Navigant team leveraged data from national studies published by the U.S. Department of Energy (DOE) and the Pacific Northwest National Lab (PNNL) and adjusted to California specific values based on regulatory and market conditions.

» DOE standards and rulemaking review ensured the maximum technically feasible energy efficiency level for many measures and end uses remained same.

» Energy Star's qualified products list and shipment data provided market saturation data.

While the measure categories remained same, their definitions were updated in some cases to reflect the market conditions more closely where we had better data.

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[69] *2010-2012 WO017 Ex Ante Measure Cost Study.*
2010-2012 WO013 Residential Lighting Process Evaluation and Market Characterization.
2010-2012 WO028 California Upstream and Residential Lighting Impact Evaluation.

» LEDs were redefined based on CFL definitions update. LED definitions are linked to CFL definitions, which were updated based on 2010 – 2012 EM&V studies.

» Residential Water heaters were updated from 0.77 Energy Factor (EF) to 0.82 EF due to the addition of 0.82 EF water heater measure to DEER. If a measure with same or higher efficiency than the corresponding ET efficiency was included in DEER since the 2013 Study, Navigant set the minimum efficiency of the ET to match the highest efficiency description in DEER for applicable measures.

» Self-Contained Refrigerator measure was redefined to be 15% less than energy code due to redefinition of Energy Star products.

» Dishwasher measure was redefined to be EF>1.0 compared to previous round, based on code and competing conventional energy efficient measure update.

» Commercial Refrigeration Fiber Optic LED lighting measure was eliminated. Strong LED efficacy and cost improvements have led to LEDs becoming a dominant lighting technology and moving towards large market penetration in commercial refrigeration market. This resulted in nearly no future potential for this particular ET measure, as such, the Navigant team abandoned the measure from Stage 1.

Some ETs (along with some conventional technologies) are expected to decrease in cost over time. The Navigant team developed four cost reduction profiles that could apply to various ETs (and non-ETs) in the 2013 Study (see 2013 Study Appendix A). These cost reduction vectors were qualitatively assigned to each ET based on various market drivers that could drive the cost down. Navigant revised these cost reduction assignments based on the further market intelligence developed for the ET measures since the 2013 study (see Table B-1).

B.2 Updates for LEDs

The Navigant team also updated data on the cost reduction and performance improvement profiles for LED technologies. LED costs have declined rapidly in recent years (a 50% reduction in market average price from 2011 to 2015) and are expected to continue to decrease in the foreseeable future. Meanwhile, LED efficacy has been increasing and is expected to increase over 40% from 2015 to 2024. This efficacy change will continue to decrease the wattage requirements of LEDs in the future. The PG Model reflects both of these trends.

LED efficacies were updated to reflect market average products and LED efficacies have dropped compared to the 2013 Study. Previous data[70] used in the 2013 Study represented the “best performers” in the market which was based on U.S. DOE technology targets and did not represent the majority of products in the market. New data[71] in Stage 1 represents the average performance and cost which are based on historical data for LEDs. Stage 1 also uses efficacy and cost data specific to LED applications (i.e. General Service and Directional), which allowed Navigant to map the efficacy data to each LED measure more precisely. The mapping of each LED measure to its definition and application can be found in Table B-2.

LED costs were also updated to market average products based on the most recent DOE pricing study[72] conducted by PNNL. This study is purely based on bulk purchasing that DOE has done for verification of LED lighting product performance through its CALiPER and Gateway programs. As such, the analysis is not based on catalog pricing and is based on actual LED purchases at volume pricing. The Navigant team determined that this should be a good proxy and would not be inflated pricing.

Then, these LED efficacies and prices were further adjusted to represent LEDs that meet the California Energy Commission’s Voluntary Quality LED Lamp Specification[73]. The specifications are based on enhancements to the ENERGY STAR standard with a particular focus on improvements to the color temperature, consistency, and color rendering (with requirements for Color Rendering Index (CRI) greater than or equal to 90). The specification applies to screw-base and bi-pin A-lamp, flame-tip, globe, and spotlight lamps. After December 11, 2013, compliance with the specification for LED lamps became mandatory for IOU incentive program eligibility (this followed a one-year “transition period” that began when the specification came into effect on December 11, 2012).

Navigant leveraged a web-scraped database[74] of pricing and specifications for over 15,000 LED lighting products time-stamped between 2008 and 2014 for developing CRI adjustment factors. Major data sources include Home Depot, Lowes, Target, Walmart, Grainger, BestBuy, CALiPER, Gateway, GSA

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[70] Navigant. *Energy Savings Potential of Solid-State Lighting in General Illumination Applications.* Prepared for the U.S. Department of Energy, January 2012.

[71] Navigant. *Energy Savings Forecast of Solid-State Lighting in General Illumination Applications.* Prepared for the U.S. Department of Energy, August 2014.

[72] Pacific Northwest National Laboratory. *Solid-State Lighting Pricing and Efficacy Trend Analysis for Utility Program Planning.* Prepared for the U.S. Department of Energy, October 2013.

[73] http://www.energy.ca.gov/2012publications/CEC-400-2012-016/CEC-400-2012-016-SF.pdf

[74] Navigant Web-Scrape LED Product Database

Advantage, Platt, ACE Hardware, Amazon.com, and 1000bulbs.com. This extensive resource of data enables the development of LED price estimates for a variety of product categories ranging from LED lamps (A-line, Globe, decorative, BR, PAR, R, MR, etc.) to luminaires (downlights, track fixtures, surface mounted/recessed troffers, panels, high/low bay, etc.) to outdoor fixtures. The database also holds a variety of information on each product entry including wattage, lumen output, CCT, CRI, voltage, dimmability, Energy Star qualified, and number of product reviews.

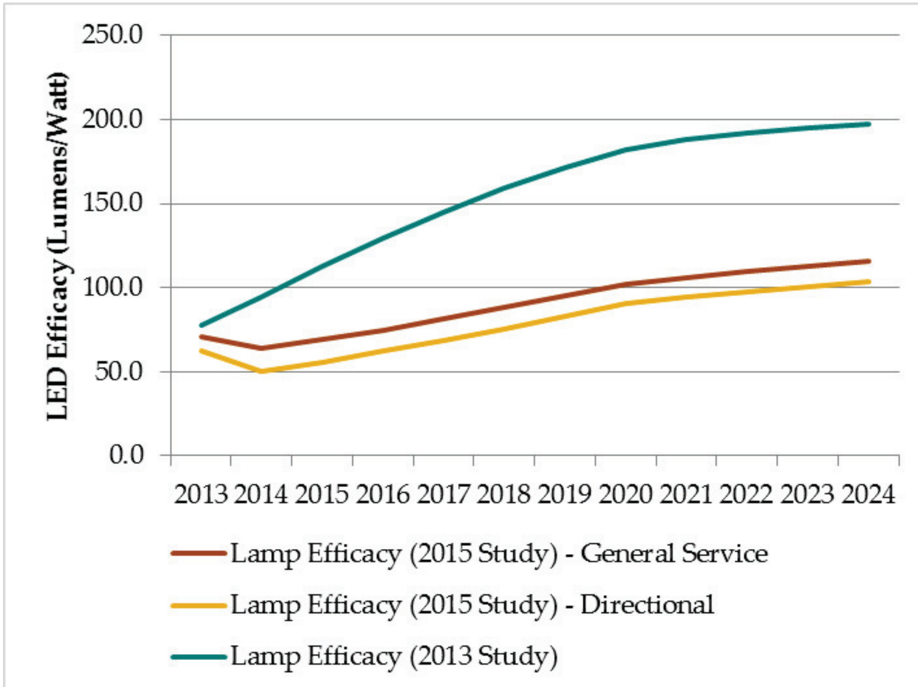
From this dataset the Navigant team analyzed how variations in LED performance affect LED efficacy and selling price. This ability enabled the team to evaluate the efficacy and the price premium associated with LEDs that meet the California Energy Commission's Voluntary Quality LED Lamp Specification.

Although the CPUC Ex Ante Measure Cost Study examined some LED technologies, the information contained in the report was collected in 2013 and is already obsolete because of the rapid evolution of the LED market

The current database includes location specific data for California and these data were analyzed to determine average efficacy and price in 2014 for CRI greater than or equal to 90, compared to CRI less than 90. From this comparison, the Navigant team then developed estimates for the average percentage change in efficacy and price associated with products that offer CRI greater than or equal to 90 for each LED measure.

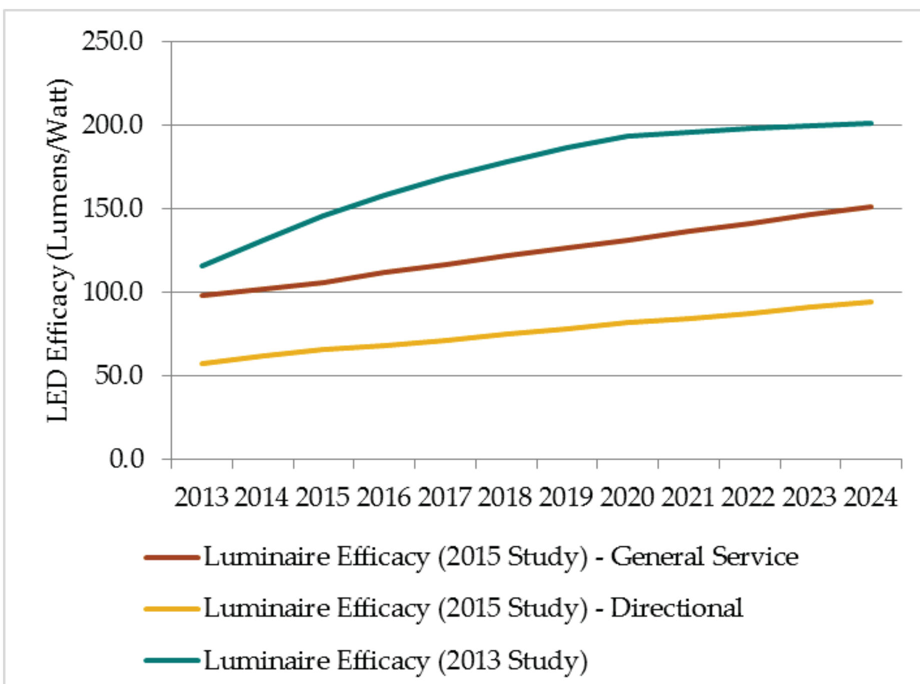
On average efficacies were adjusted by 16-19% and prices were adjusted by 10-12% starting in 2014 with the percentage adjustment decreasing over time to almost 0% by 2020. The Navigant team assumed the average CRI for LEDs in the California market will catch up with the Voluntary Quality LED Lamp Specification over time. As such, in couple years there will be no premium associated with LED products that meet the CRI requirement compared to the DOE study LED efficacies and prices for market average products. Figure B-1 and Figure B-2 illustrate the difference in LED efficacies used in both studies from 2013 to 2024. The small drop in the LED lamp efficacies from 2013 to 2014 shown in Figure B-1 is due to the Voluntary Quality LED Lamp Specification going into effect in 2014. Figure B-3 and Figure B-4 illustrate the difference in LED prices used in both studies from 2013 to 2024. Additional details on which LED measure are General Service and which are Directional can be found in Table B-2.

Figure B-1: LED Technology Improvements (Lamps)



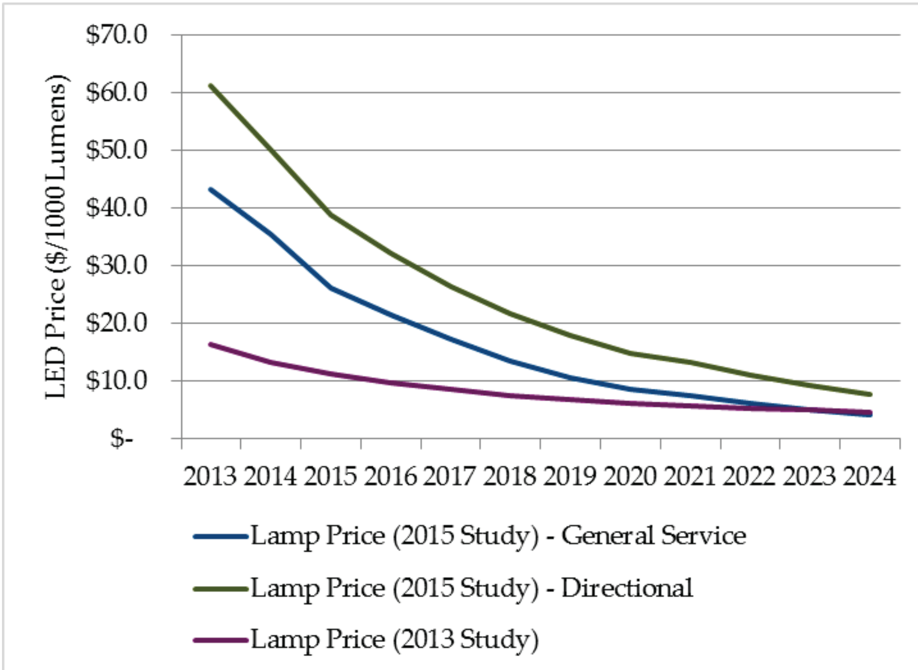
Source: Navigant team analysis 2015.

Figure B-2: LED Technology Improvements (Luminaires)



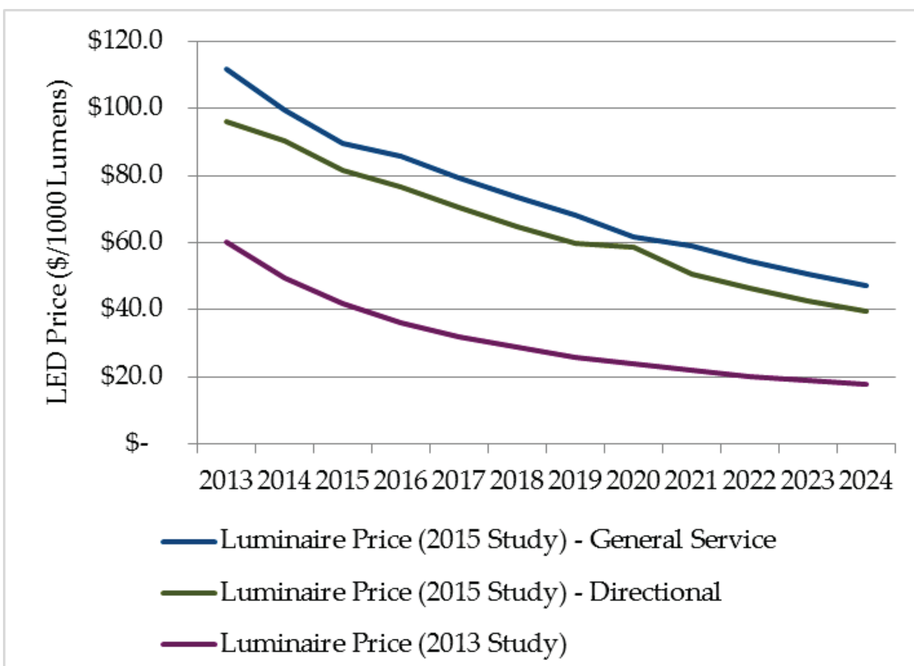
Source: Navigant team analysis 2015.

Figure B-3: LED Cost Reduction Profiles (Lamps)



Source: Navigant team analysis 2015.

Figure B-4: LED Cost Reduction Profiles (Luminaires)



Source: Navigant team analysis 2015.

B.3 Emerging Technology Risk Factor

In the 2013 Study, the Navigant team assigned a risk factor to each ET to account for the inherent uncertainty in the ability for ETs to produce reliable future savings. Actual future adoption of ETs will vary depending on technology. Some ETs may gain large customer acceptance, capture significant market shares, and generate large savings, while others may falter achieving no market share and no savings. It is impossible to pre-determine which ETs will succeed and which will fail. The ET risk factor acts to de-rate the market adoption of each individual ET. The result is a total ET savings value that is representative of what can be expected of the group of ETs. In Stage 1, the Navigant team revised the risk factors based on the same qualitative metrics that were used previously which included market risk, technical risk, and data source risk. The framework for assigning the risk factor is shown in the 2013 Study.

Navigant's logic for revising the risk factors was based on the success of the measure meeting one or more of the following criteria since the 2013 Study:

- Has overcome some of the market barriers identified previously;
- Has established strong distribution channels;
- Has resolved remaining technology issues; and
- Has produced evaluated energy savings that are equal to current (unevaluated) savings claims.

B.4 Emerging Technology Key Descriptors

Table B-1 lists the emerging technologies included in this study along with their descriptions, market introduction year, applicability, and risk factor and technology improvement parameters.

Table B-2 maps LED technologies to their measure description, LED type, and proxy LED market technology.

Table B-1: Measure Level Details of ETs Included in the 2015 Potentials and Goals Study

Sector	Fuel Type	Efficiency Measure	Base Case Description	Measure Market Introduction Year	Technology Applicability	Risk Factor	Cost Reduction Profile	Efficient Consumption Reduction Profile
RES	Electric	Clothes Washer All Sizes, Electric DHW, Electric or Gas Dryer - Average MEF = 2.87, Average Capacity = 2.93 Gallons	Clothes Washer All Sizes, Electric DHW, Electric or Gas Dryer - Average MEF = 0.78, Average Capacity = 2.93 Gallons	2012	100%	20%	Low	None
RES	Gas	Clothes Washer All Sizes, Gas DHW, Electric or Gas Dryer - Average MEF = 2.87, Average Capacity = 2.93 Gallons	Clothes Washer All Sizes, Gas DHW, Electric or Gas Dryer - Average MEF = 0.78, Average Capacity = 2.93 Gallons	2012	100%	20%	Low	None
RES	Electric	Energy Star® Dish Washer - Standard Size w/Electric Water Heater - 160 Cycles per Year - EF = 1.0	Dish Washer - Standard Size w/Electric Water Heater - 160 Cycles per Year - Average EF = 0.45	2012	100%	30%	Low	None
RES	Gas	Energy Star® Dish Washer - Standard Size w/Electric Water Heater - 160 Cycles per Year - EF = 1.0	Dish Washer - Standard Size w/Gas Water Heater - 160 Cycles per Year - Average EF = 0.45	2012	100%	30%	Low	None
RES	Electric	Heat Pump Electric Clothes Dryer	Average Market Baseline Clothes Dryer	2016	100%	50%	Medium	None
RES	Electric	Emerging Tech Refrigerator - 15% less energy than code	Code Refrigerator	2012	60%	35%	Low	None
RES	Electric	Home office - Smart Strip with one control outlet, four controlled outlets, and two constant outlets	Power Strip	2008	100%	25%	Medium	None
RES	Electric	Home theater - Smart Strip with one control outlet, four controlled outlets, and two constant outlets	Power Strip	2008	100%	25%	Medium	None
COM	Electric	Advanced Rooftop Unit AC, EER 12, COP 3.52, Advanced Economizer and Controls	Package EER Rated dxAC - Average EER = 9.68	2014	100%	45%	Medium	None
COM	Electric	Energy Recovery Ventilation system for commercial HVAC	No Energy Recovery Ventilation system	2009	12%	50%	Medium	None

Sector	Fuel Type	Efficiency Measure	Base Case Description	Measure Market Introduction Year	Technology Applicability	Risk Factor	Cost Reduction Profile	Efficient Consumption Reduction Profile
RES	Gas	Furnace Upgrade to Efficient Furnace - Average AFUE = 98	Base Case Furnace - Average AFUE = 76.8, Average HIR = 1.25	2015	100%	10%	Low	None
RES	Electric	22 SEER Split-System Air Conditioner	Residential SEER-rated split Air Conditioners, 18-65 kBTU/h; pre-2001: SEER = 10 (EER = 8.52), one-speed fan; post-2001: SEER = 13 (EER = 11.08), one-speed fan; 2014: SEER = 14 (EER = 11.82), one-speed fan	2015	100%	20%	Medium	None
RES	Electric	Split SEER-Rated Heat Pump - Average SEER = 21	Res SEER-Rated Splt HP, 7.1-3.01 kBTU/h; pre-2001: SEER = 10 (HSPF = 7.1), one-speed fan; post-2001: SEER = 13 (HSPF = 8.2), one-speed fan; 2014: SEER = 14 (HSPF = 8.2), one-speed fan	2015	100%	20%	Medium	None
COM	Electric	LED fixture: 33W, 3500 lumens	LF fixture: T8, 48inch, 32W lamp (2), Total fixture Watts = 59; Ballast specs: Instant Start, Electronic, NLO, 2 per lamp; Lamp specs: 3175 lumens, CRI=70, rated hours = 20000	2011	100%	20%	LED Luminaire - General Service	LED Luminaire - General Service
COM	Electric	LED interior lamp: 24W, 1700 lumens	Indoor Incandescent Lamp (Screw-In >= 25W) - Average Lamp Watts = 131.89W, Average Lamp CFL Ratio = 0.357	2011	100%	25%	LED Lamp - Directional	LED Lamp - Directional
RES	Electric	LED Screw-In Indoor Lamp: 16.5W, 1300 lumens	Incandescent, Screw-In Indoor 81.5W	2011	100%	25%	LED Lamp - Directional	LED Lamp - Directional
RES	Electric	LED Screw-In Outdoor Lamp: 16.5W, 1200 lumens	Incandescent Screw-In Outdoor, 87W	2011	100%	25%	LED Lamp - Directional	LED Lamp - Directional
COM	Electric	LED interior lamp: 11W, 900 lumens	Indoor Incandescent Lamp (Screw-In < 25W) - Average Lamp Watts = 58.13W, Average Lamp CFL Ratio = 0.357	2011	100%	20%	LED Lamp - General Service	LED Lamp - General Service

Sector	Fuel Type	Efficiency Measure	Base Case Description	Measure Market Introduction Year	Technology Applicability	Risk Factor	Cost Reduction Profile	Efficient Consumption Reduction Profile
RES	Electric	LED Screw-In Indoor Lamp: 8W, 675 lumens	Incandescent Screw-In Indoor, 46W	2011	100%	20%	LED Lamp - General Service	LED Lamp - General Service
RES	Electric	LED Screw-In Outdoor Lamp: 9W, 700 lumens	Incandescent Screw-In Outdoor, 57W	2011	100%	20%	LED Lamp - General Service	LED Lamp - General Service
RES	Electric	LED Screw-In Indoor Reflector Lamp: 12W, 850 lumens	Incandescent Screw-In Indoor, 71.5W	2011	100%	20%	LED Lamp - Directional	LED Lamp - Directional
RES	Electric	LED Screw-In Outdoor Reflector Lamp: 14W, 1000 lumens	Incandescent Screw-In Outdoor, 76W	2011	100%	20%	LED Lamp - Directional	LED Lamp - Directional
RES	Electric	LED Screw-In Indoor Specialty Lamp: 10W, 780 lumens	Incandescent Screw-In Indoor, 42W	2011	100%	20%	LED Lamp - General Service	LED Lamp - General Service
RES	Electric	LED Screw-In Outdoor Specialty Lamp: 11W, 870 lumens	Incandescent Screw-In Outdoor, 38W	2011	100%	20%	LED Lamp - General Service	LED Lamp - General Service
COM	Electric	LED interior fixture: 14W, 900 lumens	Incandescent interior fixture 98.8W	2011	100%	20%	LED Luminaire - Directional	LED Luminaire - Directional
RES	Electric	LED Indoor Fixture: 10W, 650 lumens	Incandescent Indoor Fixture, 79W	2011	100%	20%	LED Luminaire - Directional	LED Luminaire - Directional
RES	Electric	LED Outdoor Fixture: 10W, 700 lumens	Incandescent Outdoor Fixture, 114W	2011	100%	20%	LED Luminaire - Directional	LED Luminaire - Directional
COM	Gas	Condensing Small Gas Storage Water Heater with low Nox burner - Average Size = 51 Gal, Average EF = 0.77	Multiple base efficiency levels used, example: Small Gas Storage Water Heater - Average Size = 51 Gal; Average EF = 0.57; Average Recov Eff = 0.76	2015	80%	50%	Low	None

Sector	Fuel Type	Efficiency Measure	Base Case Description	Measure Market Introduction Year	Technology Applicability	Risk Factor	Cost Reduction Profile	Efficient Consumption Reduction Profile
RES	Gas	Small Gas Storage Water Heater - Average Size = 51 Gal, Average EF = 0.82	Small Gas Storage Water Heater - Average Size = 51 Gal; Average EF = 0.561; Average Recov Eff = 0.76	2015	100%	25%	Low	None
COM	Gas	Condensing Large Gas Storage Water Heater - Average Et = 0.99	Multiple base efficiency levels used, example: Large Gas Storage Water Heater; Et = 0.80; Stdby Loss = 0.56%/hr	2012	100%	30%	Low	None

Table B-2: LED Mapping

LED Mapping					
NEW Measure Name	**Sector**	**Efficiency Measure**	**LED Type**	**LED Mapping**	**Market Proxy**
Lighting - LED Lamp (Basic High - Indoor) - Emerging	Com	LED interior lamp: 24W, 1700 lumens	Lamp	Directional	LED R, BR, PAR Lamp
Lighting - LED Lamp (Basic Low - Indoor) - Emerging	Com	LED interior lamp: 11W, 900 lumens	Lamp	General Service	LED A-type Lamp
Lighting - LED Fixture (Replacing T8) - Emerging	Com	LED fixture: 33W, 3500 lumens	Luminaire	General Service Linear Fix.	LED Troffer Fixture
Lighting - LED Plug-In Indoor Fixture - Emerging	Com	LED interior fixture: 14W, 900 lumens	Luminaire	Directional	LED Downlight + Track
Lighting - LED Lamp (Basic High - Indoor) - Emerging	Res	LED Screw-In Indoor Lamp: 16.5W, 1300 lumens	Lamp	Directional	LED R, BR, PAR Lamp
Lighting - LED Lamp (Basic Low - Indoor) - Emerging	Res	LED Screw-In Indoor Lamp: 8W, 675 lumens	Lamp	General Service	LED A-type Lamp
Lighting - LED Lamp (Basic High - Outdoor) - Emerging	Res	LED Screw-In Outdoor Lamp: 16.5W, 1200 lumens	Lamp	Directional	LED R, BR, PAR Lamp
Lighting - LED Lamp (Basic Low - Outdoor) - Emerging	Res	LED Screw-In Outdoor Lamp: 9W, 700 lumens	Lamp	General Service	LED A-type Lamp

Lighting - LED Plug-In Indoor Fixture - Emerging	Res	LED Indoor Fixture: 10W, 650 lumens	Luminaire	Directional	LED Downlight + Track
Lighting - LED Plug-In Outdoor Fixture - Emerging	Res	LED Outdoor Fixture: 10W, 700 lumens	Luminaire	Directional	LED Downlight + Track
Lighting - LED Lamp (Reflector - Indoor) - Emerging	Res	LED Screw-In Indoor Reflector Lamp: 12W, 850 lumens	Lamp	Directional	LED R, BR, PAR Lamp
Lighting - LED Lamp (Reflector - Outdoor) - Emerging	Res	LED Screw-In Outdoor Reflector Lamp: 14W, 1000 lumens	Lamp	Directional	LED R, BR, PAR Lamp
Lighting - LED Lamp (Specialty - Indoor) - Emerging	Res	LED Screw-In Indoor Specialty Lamp: 10W, 780 lumens	Lamp	General Service	LED MR16
Lighting - LED Lamp (Specialty - Outdoor) - Emerging	Res	LED Screw-In Outdoor Specialty Lamp: 11W, 870 lumens	Lamp	General Service	LED Other

Appendix C. AIMS Sectors

C.1 Industrial

The Navigant team considered the full range of inputs for the Industrial sector to determine where new data sources exist and where existing data sources received significant updates since the 2013 Study. The following sections provide details on those update activities.

Industry Standard Practices

The Stage 1 update effort for the Industrial sector incorporated ISPs issued by the CPUC (approved for Study consideration) into the existing structure. Navigant engaged the CPUC Ex Ante Team to understand the studies for consideration. Initially, Navigant began by identifying all studies related to or partially related to ISP study efforts (i.e., risk assessment studies completed by the IOUs). Table C-1 shows the various sources initially identified by Navigant.

Mapping Industry Standard Practices

For the ISP studies deemed eligible for consideration, Navigant mapped these into the inputs structure initially developed in the 2013 Study. That is, each of the 11 ISP studies were viewed against the 273 assessment recommendation codes (ARCs) that define the measures that inform the Industrial sector potential. See the IAC database manual for additional detail[75] and the 2013 Study Appendix for details on how Navigant initially used these inputs.

Navigant's engineering team vetted each ISP study from the list of eleven (see Table C-2) to identify the associated equipment, measure activities under review, and the related Industrial subsectors where the ISP consideration pertained.

- First the team reviewed the list of 273 ARCs to estimate if the particular study would interact with a given IAC assessment recommendation. The ARC descriptions of measures are somewhat limited, but the Navigant team leveraged the ARC hierarchy scheme to confirm if an ISP study was relatable. For example, ARC 2.2622 includes the following hierarchal descriptions:
    - 2.2: Thermal systems
    - 2.26: Cooling
    - 2.262: Chillers and refrigeration
    - 2.2622: Replace existing chiller with high efficiency model
- These ISP studies often only identify a subsector or industrial area by qualitative descriptions (e.g., "automotive, medical, or packaging manufacturers"). However, Navigant related these ISP studies to subsectors, as defined by the 2013 Study, which rely on North American Industry Classification System (NAICS) codes. The team typically assigned each ISP by three digit NAICS

[75] Industrial Assessment Center. The IAC database manual. Last accessed April 2015. http://iac.rutgers.edu/manual_database.php.

(e.g., NAICS 325 for Chemical manufacturers).

- Next, for those ISP studies that Navigant linked to a subsector and ARC within the Study scope the team reviewed the studies to understand the ISP claims. That is, Navigant reviewed conclusions to understand if an ISP position existed or if one was not found through the study. Navigant further reviewed study findings for specific conditions or scenarios where ISPs do or do not exist. For example, a study might conclude that ISP exists only for new construction or only for facilities in certain regions. For these instances, Navigant estimated the impact on a given subsector as whole. A new construction ISP would generally be estimated to have negligible impact on a subsector and therefore excluded from consideration for the updates.

Navigant's full review of the ISPs found that they generally fell into one of five categories:

1. ISP established by the given study and incorporated into Industrial inputs (2 studies).
2. A study related to the Industrial sector inputs, but the study did not conclude an ISP existed. Therefore, the team did not incorporate any ISP de-ratings into Industrial inputs (1 study).
3. ISP study relates to another sector; the Mining (oil and gas extraction) sector for these instances (4 studies).
4. ISP study relates to a sector outside of the AIMS PG Study scope; e.g., wastewater treatment or parking garage ventilation fans (2 studies).
5. ISP study is highly specific and there are no relatable ARCs (2 studies); Navigant concludes that the ISPs' impact on potential is negligible given the high specificity.

Through the mapping exercise, Navigant related three studies to three ARCs from the list of 11 ISP studies initially identified for the Industrial sector and approved for consideration by the CPUC. Table C-1 shows the results of the mapping exercise and these studies can be found on the CPUC's ISP website.[76]

[76] Ibid, CPUC ISP list.

Table C-1: Industry Standard Practice Studies Initially Identified for 2015 Potential and Goals Study – Stage 1

Study Category	Source	Author/Authority	Number Initially Identified	Number Used
Finalized ISP Studies (Industrial sector)	Energy Division Ex Ante Team	CPUC/Itron, CPUC/PG&E, PG&E, SCE, SCG, SDG&E	11	3
Non-Final or Pending ISP Studies (Industrial or Commercial sectors)	Energy Division Ex Ante Team	CPUC/SCG, PG&E, SCE, SDG&E	9	0
Other Finalized ISP Studies (Commercial sector)	Energy Division Ex Ante Team	CPUC, SCE	1*	0
Risk Assessment Studies	SCE/ASWB Engineering	SCE/ASWB Engineering	34 (excluding 6 studies identified and accounted for by Ex Ante Team)	0
Total			**55**	**3**

Source: Navigant team analysis of various ISP and risk assessment studies (2015)
**Navigant initially identified only one study that related to the Commercial sector when in fact it was found later in the update effort that one of the 11 Industrial ISP studies also related to the Commercial sector.*

With CPUC guidance, Navigant screened the list to include only those finalized ISP studies (Industrial sector) that had been developed through the Energy Division Ex Ante Team and deemed viable by the CPUC for use in the 2015 update. That is, the 11 studies shown in the first row of Table C-1. For example, Navigant explored a range of studies and risk assessment reports, and these were ultimately excluded from this specific effort. CPUC considered these risk assessment studies as lower rigor efforts that support rebate eligibility decisions that are not applicable for this Potential Study. CPUC posted completed studies online for reference.[77] Table C-2 shows the studies within the initial scope of consideration.

The Stage 2 effort will continue the discussion with the CPUC and stakeholders to determine how the ISP study process can be refined to better support the needs of potential forecasting, and to assess how to best use lower rigor risk assessments and other market data.

[77] Navigant reviewed a total of 11 studies deemed eligible for consideration by the CPUC. Nine of those studies are posted online. ISP positions are stated for the remaining two and Navigant reviewed those, but formal reports have not yet been prepared and posted online yet. Ibid, CPUC. ISP List.

Table C-2: Industry Standard Practice Studies Mapping Exercise

Study Title	ISP Mapped to Industrial Sector?	Considerations (or reasons for exclusion)
Oil Pipeline Pump Motor VFDs	No	Accounted for in Mining sector.
CO Demand Control Ventilation for Enclosed Parking Structures - VFD Airflow Modulation	No	Commercial related, parking structures that are not specifically targeted by the Industrial sector.
Industry Standard Practice for Outdoor Steam Pipe Insulation for Oil-fields in California	No	Accounted for in Mining sector.
Cement Industry Standard Practice to Add a Percentage of Limestone During Grinding	No	Not included. ISP is extremely specific and the measure inputs do not account for this specific application/measure. Estimating the application of this ISP would result in negligible impacts on Industrial potential.
Juice Tank Insulation	Yes, but no ISP concluded	IAC ARC: *Use economic thickness of insulation for low temperatures.*
Injection Molding Machine Industry Standard Practice Study	Yes	IAC ARC: *Replace hydraulic/pneumatic equipment with electric equipment.*
Industry Standard Practice Assessment For Artificial Lift Pump Control Technologies	No	Accounted for in Mining sector.
Almond Drying Exhaust Air Recirculation Summary*	Yes	IAC ARC: *Utilize outside air instead of conditioned air for drying.*
Oilfield WW Pump Controls Summary_v1_Sanitized*	No	Accounted for in Mining sector.
Wastewater Treatment Plant Pumps VFD - v1	No	Wastewater facility related, not specifically targeted by the Industrial sector.
Low-Rigor ISP Study on Thermal Oxidizers in Plastic Bag Industry	No	Not included. ISP is extremely specific and the measure inputs do not account for this specific application/measure. Estimating the application of this ISP would result in negligible impacts on Industrial potential.

Source: Navigant team analysis of CPUC approved ISP studies (2015)
**Final report drafts of these studies are currently not available on the CPUC website.*

Applying New ISPs to Model Structure

Navigant updated the inputs developed with the 2013 Study structure to incorporate these new ISPs, namely, the studies related to injection molding and almond drying exhaust air recirculation (while the third study on juice tank insulation is excluded because no ISP was found from that study effort). Specifically, Navigant updated the de-rating factors estimated in the 2013 Study for the associated ARCs: 2.4324 and 2.2711. The de-rating factors from the 2013 Study apply to the entire industry whereas these ISP findings apply to the ARCs only for a given portion of Industrial subsectors. Therefore in order to make these recent ISP findings relatable, Navigant conducted the following steps:

- **Measure Equipment Densities:** Navigant reviewed ARCs against subsectors to estimate measure equipment densities. Measure equipment densities are an estimate of the measure densities, or saturations, and are the product of two parameters.
  - **Measure applicability (or total technology density):** As an example for the almond drying exhaust air recirculation ISP study: Navigant estimated that the identified ARC, ARC 2.2711, relates only to six of the 15 established subsectors.
  - **Baseline density:** The Navigant team of expert engineers estimated the saturation of baseline equipment (or the portion of equipment that could be converted to efficient equipment). This is, about 50 percent of the related equipment are at the baseline efficiency level for the given example.
  - **Combining the two parameters:** In terms of energy consumption for the example, Navigant's analysis estimated that ARC 2.2711 relates to only approximately 18 percent of the consumption associated with process cooling and refrigeration end-uses. This is the measure equipment density associated with the ARC.
- **ISP Multiplier:** Continuing the example for ARC 2.2711 and the exhaust air ISP, Navigant's analysis found that the ISP study only relates to the Food subsector (NAICS 311 and 312). Therefore, ARC 2.2711 should only be de-rated for the Food subsector. When considering each subsector's energy consumption, this exercise results in an Industrial sector ISP multiplier of 83 percent for this ARC.
- **Updated De-rate Factor:** The measure equipment density and ISP multiplier are then combined to estimate the new de-rate factor. From the previous example: 18 percent multiplied by 83 percent to arrive at a 15 percent de-rate factor. That is, 15 percent of the original savings reported within the IAC database are applicable to the California market. This value is uploaded into the Industrial inputs and replaces the de-rate factor established during the 2013 Study for ARC 2.2711.

Table C-3 shows the results of this exercise. The list only contains three ISP studies and related ARCs and only two de-rating factor updates. However, Navigant applied the review process to the full list of ISP studies and ARCs to confirm applicability. Further, this analysis approach developed during this 2015 Study can be redeployed for future potential study efforts and after the issue of new ISP studies if the current model framework remains.

Table C-3: Results of the Derating Factor Update Exercise

Study Title	IAC ARC	Application?	Applicable Subsectors (NAICS)	Measure Equipment Density	ISP Multiplier	De-rating Factor
Juice Tank Insulation	2.2516: Use economic thickness of insulation for low temperatures.	Not ISP (only ISP for new construction); not applied to ARC	Food (311, 312)	N/A, not ISP and no updates applied (relying on 2013 de-rating value)		
Injection Molding Machine Industry Standard Practice Study	2.4324: Replace hydraulic/pneumatic equipment with electric equipment.	Applied to ARC	Electronics (334, 335) Chemicals (325) Plastics (326) Transportation Eq. (336) Other (339)	0.500	0.536	0.268
Almond Drying Exhaust Air Recirculation Summary	2.2711: Utilize outside air instead of conditioned air for drying.	Applied to ARC	Food (311, 312)	0.184	0.828	0.152

Source: Navigant team analysis (2015)

Vetting and Density Review Exercise

As mentioned in the previous exercise, the Navigant team, including engineers from ASWB Engineering, reviewed the list of 273 ARCs to vet their applicability to the California market. This vetting exercise reviewed ARCs in terms of measure equipment densities. Navigant conducted this analysis task in response to stakeholder comments and concerns raised about the IAC database being a national level database and not for California specific data. Navigant conducted quantitative reviews for similar comments received during the 2013 Study, and those details can be found in the 2013 Study Appendix G and Appendix T. This current effort built on that 2013 Study work and augment findings with additional expertise from team members familiar with the California Industrial sector and IOU program activities and eligibility requirements.

Navigant's review identified instances where certain ARCs were not fully applicable to California (e.g., cold climate IAC ARCs not applicable in California's milder climate, etc.) or where California or Federal regulations make certain ARCs ineligible (e.g., OSHA requirements for hot surface insulation). Also, the team reviewed ARCs in consideration of California energy efficiency program requirements to identify instances were ARCs are not eligible due to programmatic constraints such as restrictions on maintenance improvements and combined heat and power (CHP) measures.

The results of this exercise confirmed the de-rating factors established for the list of 273 ARCs during the 2013 Study effort.

Preserving 2013 Study De-rating Factors

Finally, after confirming the validity of the 2013 de-rating inputs Navigant updated the values with the recent findings from the ISP review and mapping exercise. Of the 273 ARCs that inform the Industrial potential model Navigant only updates two values as shown in Table C-4 while the remainder were left unchanged from the 2013 study.

Table C-4: Updated De-rating Factors

ARC Description	ARC	2013 De-rating Factor	2015 De-rating Factor
Replace hydraulic / pneumatic equipment with electric equipment	2.4324	0.670	0.268
Utilize outside air instead of conditioned air for drying	2.2711	0.667	0.152

Source: Navigant team analysis (2015)

Other Data Reviews and Updates

Navigant reviewed the other data sources that inform the Industrial inputs to determine where updates to information were warranted. The following subsections provider further details.

Industrial Assessment Center Database

The 2013 Study relied on IAC database records from 2004 to 2012; 2012 is the most recent year with available data. For Stage 1 the Navigant team reviewed the IAC database updates and found additional recommendations made at facilities and recorded in the database for years 2013 and 2014. For those two additional years the IAC added approximately 9,000 measures. Navigant conducted a sensitivity analysis to understand the change in average savings per ARC resulting from the addition of the new data. Table C-5 provides the details of those findings.

Average electric and gas savings per measure (per ARC), as a percent of facility consumption, only changed by 0.03 percent and 0.16 percent, respectively. Therefore, Navigant concluded that the overall changes in the IAC database are negligible, and the team excluded these additional measures and preserved the IAC database inputs used for the 2013 Study.

Table C-5: IAC Database Analysis of Updates

ARC Description	Electric ARCs	Gas ARCs
Additional ARCs (recommendations made in 2013 and 2014)	6,294	2,636
Average savings per ARC from 2004 to 2012 dataset (% of facility consumption)	2.73%	6.41%
Average savings per ARC from 2004 to 2015 dataset (% of facility consumption)	2.70%	6.25%

Source: Navigant team analysis (2015)

Subsector Consumption Data: Quarterly Fuel and Energy Report (QFER)
Navigant obtained updated QFER data (new data for years 2012 and 2013) from the CEC to support the Stage 1 updates.[78] These data specify energy consumption by NAICS and Navigant uses these date to estimate subsector distributions. Navigant notes that QFER updates were only available for electric consumption data, and gas consumption data were not available at the time of the update. Also, Navigant did not anticipate significant changes or shifts in NAICS subsector distributions of energy consumption in the Industrial sector. Therefore, Stage 1 relies on the distributions developed for the 2013 Study.

Subsector Forecasts Data: Integrated Energy Policy Report
Navigant also obtained updated IEPR forecasts from the CEC.[79] Similar to the QFER data, only electric forecasts for energy consumption (kWh) and retail rates ($/kWh) were available at the time of the study. Therefore, the team updated electric forecasts for Stage 1, but the gas forecasts remain unchanged from the 2013 Study.

The IEPR Industrial electric consumption forecasts reduced from the 2013 Study and this reflects a correction to account for Publicly Owned Utilities (POUs) that reside within the larger IOU planning areas. For the planning areas in their entirety (i.e., without considering the reduction resulting from excluding POUs), IEPR estimates a decrease in consumption for PG&E and SDG&E, and an increase for SCE.

Table C-6: IAC Database Analysis of Updates

IOUs	As a percent of the 2013 Forecast Value (average for years 2015 to 2024)	
	Excluding POUs	Excluding POUs
PG&E	76.6%	76.3%
SCE	87.9%	93.9%
SDG&E	100%	92.9%

Source: Navigant team analysis (2015)

The CEC also updated retail rate forecasts to show a slight increase for all IOUs except for SDG&E, and Navigant incorporated these into the model.

[78] CEC. Quarterly Fuel and Energy Report. Last accessed April 2015. http://energyalmanac.ca.gov/electricity/web_qfer/
[79] Ibid, IEPR.

Table C-7: IEPR Electric Retail Rate ($/kWh) Forecast Updates and Comparison

IOUs	Average Retail Rate for years 2015 to 2024	
	Excluding POUs	Excluding POUs
PG&E	$0.111	$0.124
SCE	$0.098	$0.115
SDG&E	$0.156	$0.135

Source: Navigant team analysis (2015)

Other California Data

As part of the Stage 1 update vetting activities Navigant performed similar activities carried out during the 2013 Study. These activities included a comparative metrics vetting of the initial model outputs against IOU compliance filing data.[80] In addition to obtaining feedback directly from stakeholders such as the IOU representatives, comparing results to IOU planning generally helps the Navigant team understand if program activities and ISP constraints are appropriately reflected in the model.

C.2 Agriculture

Similar to the Industrial sector, the Navigant team considered the full range of inputs and sources for the Agriculture sector to determine where new data sources exist and where existing data sources received significant updates since the 2013 Study. The Agriculture sector relies on IAC, QFER, IEPR data, DEER, and the Commercial sector Study effort inform the Agriculture sector.

Industry Standard Practices

Navigant reviewed the ISPs explored for the Industrial sector and found that no new CPUC vetted and approved ISPs exist for the Agriculture sector. The Agriculture sector relies on a similar approach as the Industrial sector in that inputs are informed by supply curves that are adjusted with de-rating factors to account for ISPs, program eligibility considerations, and other constraints that prevent programs from claiming savings. While Navigant's review found no new Agriculture-specific ISPs to incorporate into the inputs, the de-rating factors for Stage 1 change from the factors established through the 2013 Study stakeholder process. These factors are developed from a comparison of Industrial incremental market potential model runs where both de-rating factors are included and excluded. Table C-8 shows a comparison of those model runs from Stage 1 and the resulting de-rate factors that are applied to the Agriculture sector inputs. Additional details on the previous factors and on this analysis approach can be found in the 2013 Study Appendix H and Appendix T.

[80] DEER. IOU Compliance Filings. Last accessed March 2015. ftp://ftp.deeresources.com/E3CostEffectivenessCalculators

Table C-8: Derating Factors Applied to the Agriculture Sector Inputs

Fuel	Equipment Measures	O&M Measures
Electric	11.8%	26.0%
Gas	32.8%	39.9%

Source: Navigant team analysis (2015)

Other Data Reviews and Updates

Navigant reviewed the other data sources that inform the Agriculture inputs to determine where updates to information were warranted. These reviews occurred simultaneous to the same reviews conducted for the Industrial sector, and Navigant made similar conclusions with the noted differences in analysis findings. The following subsections provide details on those updates.

Industrial Assessment Center Database

Similar to the review for the Industrial sector, Navigant conducted a sensitivity analysis and concluded that the overall changes in the IAC database are negligible. Therefore, Navigant excluded additional IAC measures and preserved the IAC database inputs used for the 2013 Study.

Subsector Consumption Data: Quarterly Fuel and Energy Report (QFER) and Drought Conditions

Navigant received updated electric consumption data for the Agriculture sector. Updates for gas consumption were not available. Navigant did not anticipate significant changes or shifts in NAICS subsector distributions of energy consumption in the Agriculture sector. However, Navigant identify significant year-over-year changes in sector-wide consumption. Through further investigation, Navigant correlated increased energy consumption with drought condition years.[81] Therefore, instead of relying on the most recent single year of data, Navigant instead developed a drought-adjusted annual average in order to represent typical energy consumption. The potential model relies on typical energy consumption since savings are derived directly as a percent of energy consumption. Basing the model inputs on 2013 data would erroneously imply increased energy efficiency potential during drought conditions. Navigant reviewed QFER historical trends to develop the adjustment factor. Figure C-1 and Table C-9 show the historical data and the drought factor developed from that data.

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[81] California Drought Data. USDA. California Drought 2014: Farms. Last accessed March 2015 http://ers.usda.gov/topics/in-the-news/california-drought-2014-farm-and-food-impacts/california-drought-2014-farms.aspx

Figure C-1: Agriculture Sector Historical Consumption[82]

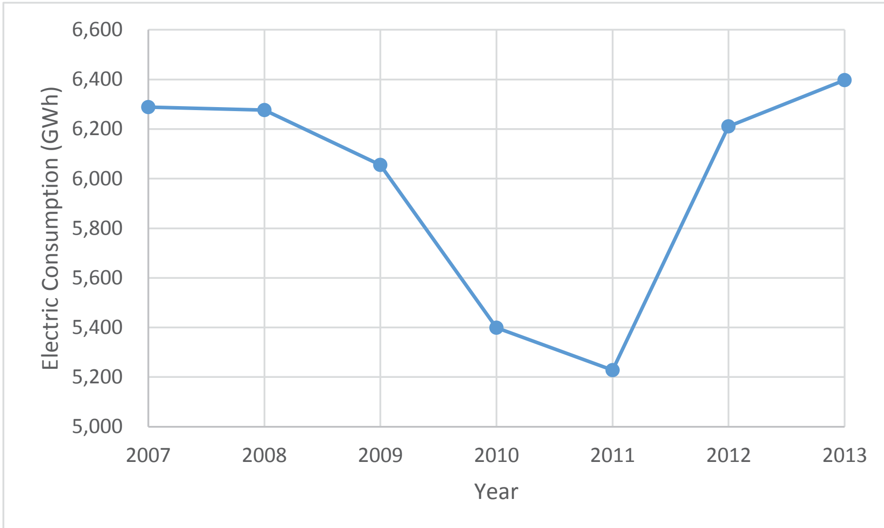

Table C-9: Agriculture Drought Factor[83]

Year	Agriculture Sector Consumption (GWh)	Drought Year?
2007	6,288	Yes
2008	6,277	Yes
2009	6,055	Yes
2010	5,399	No
2011	5,228	No
2012	6,211	Yes
2013	6,397	Yes
Average: 2007-2009 and 2012-13	**6,245**	**Yes**
Average: 2010-2011	**5,314**	**No**
Drought Factor	**0.85**	

Source: Navigant team analysis (2015)

Navigant developed drought factors in a similar manner as described in Table C-9 for the individual subsectors/end-uses examined for the Agriculture sector. Ultimately, the drought factors presented in Table C-10 inform the 2015 Potential Study and are applied to the most recent IEPR forecast data that reflects increased energy consumption due to drought conditions. That is, the drought factor reflects the ratio of non-drought conditions to drought conditions (i.e., the average of non-drought QFER year divided by the average of drought QFER years).

[82] Ibid, QFER data.

[83] Ibid, QFER data.

Table C-10: Agriculture Subsector Drought Factors, Electric Consumption[84]

Subsector	Drought Factor	Comments on the Impacts of Drought Conditions[85]
Dairy	90.9%	Increased cooling loads required for livestock and liquid storage.
Irrigated Agriculture	75.0%	Increased pumping energy required to lift water from lower water tables.
Greenhouses and Nurseries	97.8%	Negligible impact; slight cooling load increases expected.
Vineyards and Wineries	77.0%	Increased cooling loads required for liquid storage.
Concentrated Animal Feeding Operations	89.6%	Increased cooling loads required for livestock.
Refrigerated Warehouses	99.5%	Negligible impact; slight cooling load increases expected.
Post-Harvest Processing	94.8%	Minor impact; slight cooling load increases expected for indoor facilities.

Source: Navigant team analysis (2015)

Subsector Forecast Data: Integrated Energy Policy Report

Navigant obtained updated IEPR forecasts.[86] Similar to the Industrial sector, only electric forecasts for energy consumption (kWh) and retail rates ($/kWh) were available at the time of the study. Also, Industrial and Agriculture retail rates are the same (see Table C-7 for changes). The team updated electric forecasts for Stage 1, but the gas forecasts remain unchanged from the 2013 Study.

As previously discussed for the development of the drought factor, Navigant initially reviewed the IEPR electric consumption forecasts for the IOUs and identified a significant increase in the forecast between the 2013 Study inputs and the most recent IEPR release. This increase aligns with the difference seen in QFER data for drought and non-drought years.

[84] Ibid, QFER data.

[85] Based on Navigant's engineering judgment that is also informed by recent MASI Study activities.

[86] Ibid, IEPR data.

Table C-11: Agriculture Subsector Drought Factors, Electric Consumption[87]

Subsector	Drought Factor
2006	100%
2007	100%
2008	100%
2009	101%
2010	98%
2011	87%
2012	106%
2013	114%
2014	115%
2015	116%
2016	117%
2017	117%
2018	118%
2019	119%
2020	120%
2021	121%
2022	122%
2023	123%
2024	125%
2015 to 2024 Average	**120%**

Source: Navigant team analysis (2015)

Navigant also reduced the IEPR Agriculture electric consumption forecasts to remove POU energy consumption that reside within the larger IOU planning areas. Table C-12 shows the consumption forecasts that reflect the adjustment for drought conditions and exclusion of POUs.

Table C-12: Agriculture IEPR Electric Consumption (kWh) Forecast Updates

IOUs	As a percent of the 2013 Forecast Value (average for years 2015 to 2024)	
	Excluding POUs	Excluding POUs
PG&E	86.1%	91.0%
SCE	62.4%	60.4%
SDG&E	100%	92.9%

Source: Navigant team analysis (2015)

[87] Ibid, IEPR data.

DEER Data

Navigant relied on the same data from the 2013 Study when characterizing gas measures for greenhouses. These data augment the IAC database for the Agriculture sector inputs and include DEER and other analyses developed from secondary sources such as USDA Virtual Grower. DEER serves as the majority source for these measures and Navigant reviewed DEER and found no updated information. Therefore those specific inputs from the 2013 Study remain unchanged.

Commercial MICS

Similar to the DEER data, Navigant also supplemented the Agriculture inputs with sources other than IAC data for HVAC and water heating measures found in winery and vineyard operations. These are sourced from the Potential Study's Commercial sector inputs that include measure details on water heaters and building shell insulation. Navigant did not find any new sources or data to update these commercial measures, and therefore, these inputs for the Agriculture sector remain unchanged from the 2013 Study.

Other California Data

As part of the Stage 1 update vetting activities Navigant performed similar activities carried out during the 2013 Study. These activities included a comparative metrics vetting of the initial model outputs against IOU compliance filing data.[88] Similar to the Industrial sector reviews, comparing results to IOU planning helps the Navigant team understand if program activities and constraints (ISP, programmatic, regulatory, etc.) are appropriately reflected in the model.

C.3 Mining

Similar to the other AIMS sectors, Navigant considered the range of inputs and sources for the Mining sector to determine where new data sources exists and where existing data sources received significant updates since the 2013 Study. Unlike the Industrial and Agriculture sectors, the Mining sector relies on an approach more similar to the Residential and Commercial sectors. Inputs are developed from the bottom up and define specific measures instead of more broadly defined end-uses. Navigant determined that there are no significant updates for certain measure-specific parameters such as baseline and measure level efficiencies or equipment costs. However, Navigant reviewed the range of sources to both vet the 2013 Study inputs as well as identify any new or updated sources to consider that apply to the market more generally such as sector level consumption data.

Industry Standard Practices

Following the analysis of the Industrial sector ISPs, Navigant identified ISPs issued and approved by the CPUC that apply to the Mining sector (and more specifically the oil and gas extraction subsector). During the 2013 Study, Navigant also engaged the CPUC Energy Division (ED) Ex Ante Team for

[88] Ibid, DEER. IOU Compliance Filings.

guidance on how ISPs affect energy efficiency potential within the sector. The ISP studies identified through this recent effort are reflected in the input previously provided by the Ex Ante Team. Table C-13 shows the ISPs related to the Mining sector and how they influence the Potential Study inputs.

Table C-13: Industry Standard Practice Studies Relating to Mining Sector[89]

Study Title	Incorporated into Inputs?	Considerations (or reasons for exclusion)
Oil Pipeline Pump Motor VFDs	No	Midstream surface transport pumps are currently excluded from the Study scope (however, savings from pumps retrofitted with VFDs are de-rated to reflect ISP- see other studies)
Industry Standard Practice for Outdoor Steam Pipe Insulation for Oil-fields in California	Yes	Savings from improvements to steam boiler operations de-rated to reflect ISP
Industry Standard Practice Assessment For Artificial Lift Pump Control Technologies	Yes	Savings from pump-off controller (POC) and VFD installations de-rated to reflect ISP
Oilfield WW Pump Controls Summary_v1_Sanitized*	Yes	Savings from VFD installations de-rated to reflect ISP (new construction in addition to retrofits)

Source: Navigant team analysis (2015)

**Final report drafts of these studies are currently not available on the CPUC website.*

Major and Minor Market Segmentations

Within the oil and gas extraction subsector, ISP considerations are typically a function of organizational size. "Majors" are often subject to more conservative ISP considerations and only "minors" are typically eligible for certain energy efficiency measures. During the 2013 Study Navigant received guidance from the Ex Ante Team that approximately 80 percent of California oil production originated from major producers. This estimate informed the 2013 Study inputs and final Mining sector de-ratings. Navigant confirmed this market bifurcation as part of Stage 1 update by identifying the guidance published by SCE in September 2013 that also sourced guidance from ED. Table C-14 summarizes that guidance. Ultimately, the major-minor market distribution developed for the 2013 Study remains unchanged for Stage 1. Navigant's initial estimate is informed by a review of the 30 largest producers within the state, and the team does not anticipate any significant shifts for that market characteristic in the past two years.

[89] Ibid, CPUC ISP list.

Table C-14: Mining (Oil and Gas Extraction) Major and Minor Market Share Distributions[90]

Designation	Guidance	Market Distribution	Initial ED/CPUC Guidance (2013 Study)	2013 Study Market Distribution; Used for 2015 Study**
Major	Producing more than 2.5% of CA total oil production for 2012*	77%	About 80%	83%
Minor	Producing less than 2.5% of CA total oil production for 2012*	23%	About 20%	17%

Source: Navigant team analysis (2015)
**Approximately 198 MM barrels produced in 2012.*
***This distribution developed through a review of the 30 largest producers within the state.*

Other Data Reviews and Updates

Navigant reviewed the other data sources that inform the Mining inputs to determine where updates to information were warranted. The following subsections provide details on those updates.

Subsector Consumption Data: Quarterly Fuel and Energy Report (QFER)

Navigant obtained updated QFER data from the CEC to support the Stage 1 updates.[91] For the Mining sector inputs, Navigant relies on the total QFER data to vet the sector-wide roll up of consumption developed as part of the bottoms-up analysis approach. Specifically, Navigant uses the QFER data to vet the equipment stock estimates.

Navigant notes that QFER updates were only available for electric consumption data, and gas consumption data were not available at the time of the update. Consumption for the oil and gas extraction subsector (NAICS 211 and 213) has fallen from 2011 to 2013, but increased overall by 9 percent from 2007 to 2013. Year-over-year changes in consumption reflect production levels that are driven by many factors including economic and regulatory ones. Due to the relatively small changes in sector-wide consumption in recent years Navigant's vetting of QFER data ultimately concluded that no changes to the equipment stocks are warranted.

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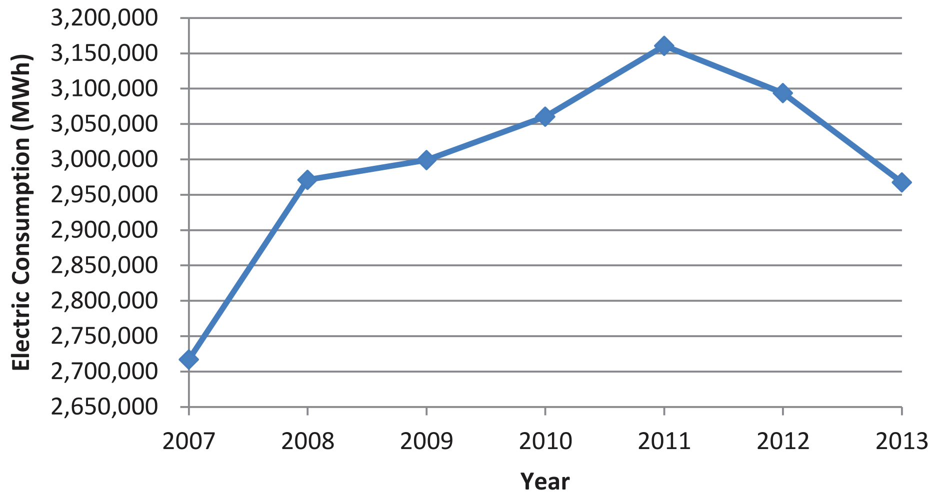
[90] Oil Industry Major and Minor Company Guidance. Last accessed: April 2015. http://www.caasupport.com/2013/09/oil-industry-major-minor-company-guidance/
[91] Ibid, QFER.

Figure C-2: Oil and Gas Extractor Subsector Electric Consumption (MWh)[92]



Energy Consumption Data Management System

The Mining sector is also informed by the Energy Consumption Data Management System (ECDMS) maintained by the CEC. Navigant uses this data to inform the distribution of sector activity among the IOUs. Similar to the QFER data update, Navigant did not anticipate a significant change in distributions. However, Navigant did apply Stage 1 findings shown in Table C-15 to the inputs. Table C-15 shows ECDMS data for the Mining sector that, in addition to oil and gas extraction, includes mineral mining and construction energy consumption that are currently outside of the scope of the Potential Study. For example, Navigant estimates that the consumption shown in Table C-15 for SDG&E relates only to mineral mining and/or construction.

Table C-15: Mining Sector IOU Consumption Distributions[93]

IOU	Electric Consumption Share (% of IOUs)		Gas Consumption Share (% of IOUs)	
	2013 Study	2015 Study	2013 Study	2015 Study
PG&E	46.5%	48.6%	9.1%	7.1%
SCE/SCG	48.8%	47.4%	90.5%	91.5%
SDG&E	4.7%	4.0%	0.4%	1.4%

Source: Navigant team analysis (2015)

California Department of Conservation Data

Navigant relies on oil and gas extraction statistics published by the California Department of Conservation for a significant portion of the Mining sector inputs. During the 2013 Study Navigant

[92] Ibid, QFER data.

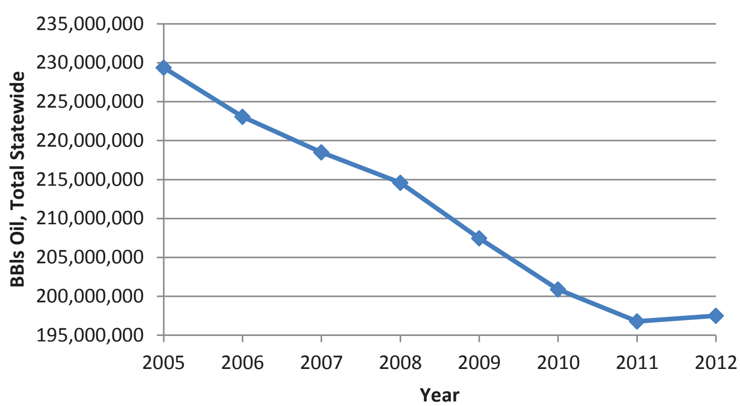
[93] CEC. California Energy Consumption Database. Last accessed: April 2015. http://ecdms.energy.ca.gov/

referenced the 2009 Annual Report of the State Oil and Gas Supervisor[94] that included granular details on oil well counts, oil production levels, water production levels, injection (water, steam, other), and several other statistics for specific geographies and individual organizations/operators. Stage 1 referred to the Department of Conservation data again and also identified a 2012 study[95] update as the most recent source. Unfortunately, the most recent publications do not offer the same level of details as the 2009 study. However, Navigant leveraged this new information where it could within the updates, and this included updates to statewide oil production and well counts.

In addition to informing several specific modeling inputs, the California Department of Conservation data generally informs the approach to modeling and characterizing the Mining sector. Well counts are increasing steadily, but production is down and injection activities are up. Further, less oil is being produced, but equal and likely more energy is expended to produce it.

- Oil production levels in California are trending down (Figure C-3).
- Well completions (i.e., new wells created and made ready for use) are steady (Figure C-4).
- Total number of producing wells is trending up (Figure C-5).
- Total volume of injected fluids (i.e., liquid water or steam) is trending up (Figure C-6).

Figure C-3: Statewide Oil Production[96]



[94] CA Dept. of Conservation. 2009 Annual Report of the State Oil and Gas Supervisor. Last accessed: March 2015. ftp://ftp.consrv.ca.gov/pub/oil/annual_reports/2009/PR06_Annual_2009.pdf
[95] CA Dept. of Conservation. 2012 Preliminary Report of California Oil and Gas Production Statistics. Last accessed: March 2015. ftp://ftp.consrv.ca.gov/pub/oil/annual_reports/2012/PR03_PreAnnual_2012.pdf
[96] Ibid, CA Dept. of Conservation 2009 and 2012.

Figure C-4: Statewide Well Completions[97]

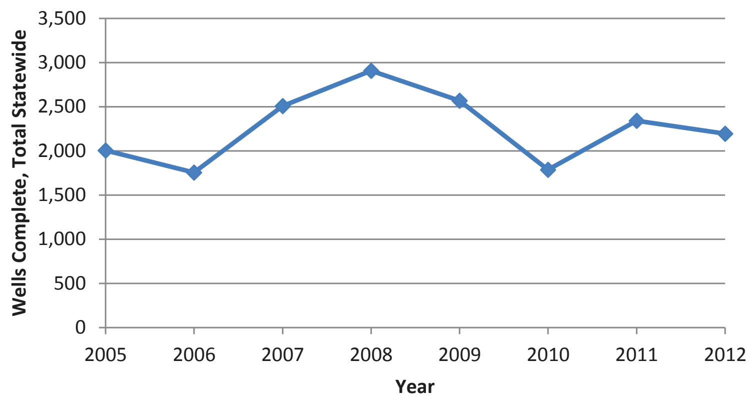
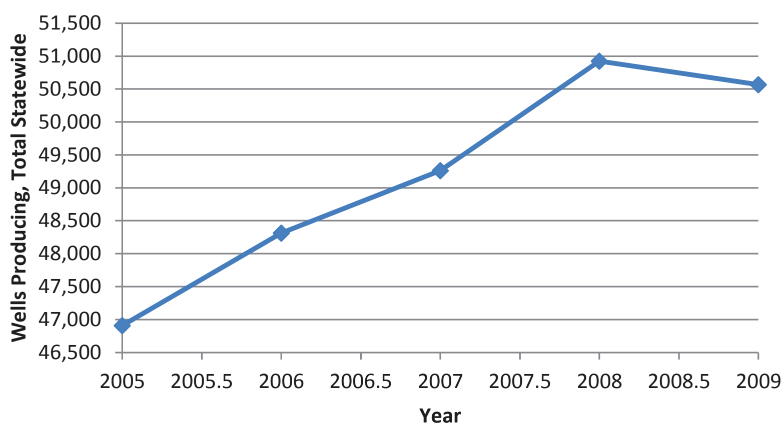
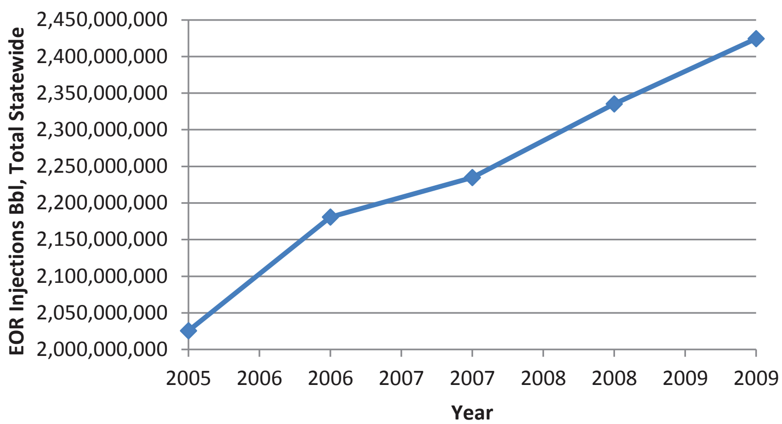


Figure C-5: Statewide Wells in Operation[98]



[97] Ibid, CA Dept. of Conservation 2009 and 2012.
[98] Ibid, CA Dept. of Conservation 2009.

Figure C-6: Statewide Water (steam or liquid) Injection Volumes[99]



Data Vetting

As part of the Stage 1 update vetting activities, Navigant performed similar activities carried out during the 2013 Study. These activities included a comparative metrics vetting of the initial model outputs against IOU compliance filing data.[100]

The Navigant team also reviewed key inputs to conform reasonableness and if any new data sources exists. Team members included subject matter experts familiar with the oil and gas extraction subsector, IOU programs active there, and ISP activities associated with measures within that subsector. These vetting exercises from experts supplement initial input received from other subject matter experts during the 2013 Study. Generally, the 2013 Study inputs reviewed were deemed reasonable and applicable to Stage 1. Therefore, no changes resulted from these reviews.

C.4 Street Lighting

Similar to the other AIMS sectors, Navigant considered the full range of inputs for the Street Lighting sector to determine where new data sources exists and where existing data sources received significant updates since the 2013 Study.

The 2015 Study update generally follows the methodology developed for the 2013 Study. First, Navigant used the IOU-supplied inventories and consumption data from the 2013 Study to estimate baseline and energy efficient measures for customer owned and IOU owned lamps. Sub-sector energy consumption distributions (i.e., street lights, sign lights, traffic lights) were updated from recent QFER data[101] using a bottoms-up approach and triangulated with other consumption data sources. The cost data for LEDs

[99] Ibid, CA Dept. of Conservation 2009.
[100] Ibid, IOU Compliance Filings.
[101] Ibid, QFER data.

were updated based on a forecasting study conducted by the Department of Energy (DOE) in 2014.[102] Navigant also used this study to forecast improvements in efficacies for LEDs.[103] Finally, Navigant recently obtained 2015 Street lighting inventories and consumption data from the IOUs and leveraged this data for vetting these updates.

The majority of updates relate to street lights whereas nominal changes to sign and traffic lights occurred for this update. The following sections primarily relate to street lights and additional details on sign and traffic lights can be found in the 2013 Study Appendix.

IOU Densities and Inventories

The Navigant team reviewed the inventories supplied by the IOUs for the streets subsector. The streets subsector includes incandescent, mercury vapor, low-pressure sodium, high-pressure sodium, metal halide, LED, and induction lamps. Because the Potential Model uses 2013 as a basis year, the Navigant team maintained the 2013 Study distribution of these technologies by lamp count across the subsector while the 2015 distributions supplied by the IOUs provided a calibration point for the Model's output. The 2015 inventories obtained from two IOUs (PG&E and SCE) reflect actual inventories. Secondary sources such as reports on Retrofit Activities for Street Lighting[104] in San Diego and Citywide Broad Spectrum Street Lighting Retrofits[105] by the City of San Diego were used to estimate SDG&E's 2015 inventory.

Similar to the 2013 Study approach, LEDs and induction lamps are considered efficient technologies while the baseline is the current mix of baseline lamp technologies: high-pressure sodium, low-pressure sodium, metal halide, mercury vapor, and incandescent. The Navigant team represented these baseline lamp types with a single lamp based on a weighted average. Estimates for the streets subsector consumption relied on the IOU-provided lamp inventories that are tied to rate schedules (e.g., LS-1 and LS-2) that specify monthly kWh charges.[106]

Per CPUC guidance for the 2015 Study, Navigant accounted for lamp ownership: customer owned versus utility owned. The potential results reflect all lamps, and Table C-16 and Table C-17 can be used to estimate separate potential for customer or IOU owned lamps only.

[102] DOE. Energy Savings Forecast of Solid-State Lighting in General Illumination Applications. August 2014, http://apps1.eere.energy.gov/buildings/publications/pdfs/ssl/energysavingsforecast14.pdf
[103] See the Emerging Technology report section for more details.
[104] City of San Diego. Retrofit Activities Summary. Last accessed March 2015
http://www.sandiego.gov/environmental-services/energy/pdf/energysavings.pdf
[105] City of San Diego. Citywide Broad Spectrum Street Lighting Retrofits. Last accessed March 2015.
http://www.sandiego.gov/environmental-services/energy/programsprojects/saving/broadspectrumretrofit.shtml
[106] LS-1 and LS-2 Rate Schedules. IOU-specific. Last accessed April 2015.

PG&E: http://www.pge.com/tariffs/ERS.SHTML#ERS
SCE: https://www.sce.com/NR/sc3/tm2/pdf/ce36-12.pdf
SDG&E: http://www.sdge.com/business/street-lighting/understanding-your-street-lighting-rates

As seen in Table C-16, the percentage of efficient lamps has increased from the previous study for PG&E and SDG&E whereas SCE remains the same in its distribution of baseline lamps and efficient lamps. This table represents both customer and IOU owned lamps.

Table C-16: Percentage of Baseline and Efficient Street Lamps by Utility

Year	Efficient Lamps (%)			Baseline lamps (%)		
	PG&E	SCE	SDG&E	PG&E	SCE	SDG&E
2013	4%	1%	23%	96%	99%	77%
2015	26%	1%	31%	74%	99%	69%

Source: Navigant team analysis of IOU-provided lamp inventories (2015)

As shown in Table C-17, the majority of lamps for PG&E and SDG&E are owned by customers, and that has not changed significantly since the last update. There is a slight increase in customer owned lamps for PG&E and a similar decrease for SCE. The majority of SCE lamps are utility owned. Navigant's analysis of secondary sources for SDG&E maintained a consistent distribution across years.

Table C-17: Percentage of Customer Owned and Utility Owned Street Lamps

Year	Customer Owned (%)			Utility Owned (%)		
	PG&E	SCE	SDG&E	PG&E	SCE	SDG&E
2013	74%	17%	81%	26%	83%	19%
2015	76%	15%	81%	24%	85%	19%

Source: Navigant team analysis of IOU-provided lamp inventories (2015)

Subsector Consumption Data: Quarterly Fuel and Energy Report (QFER)

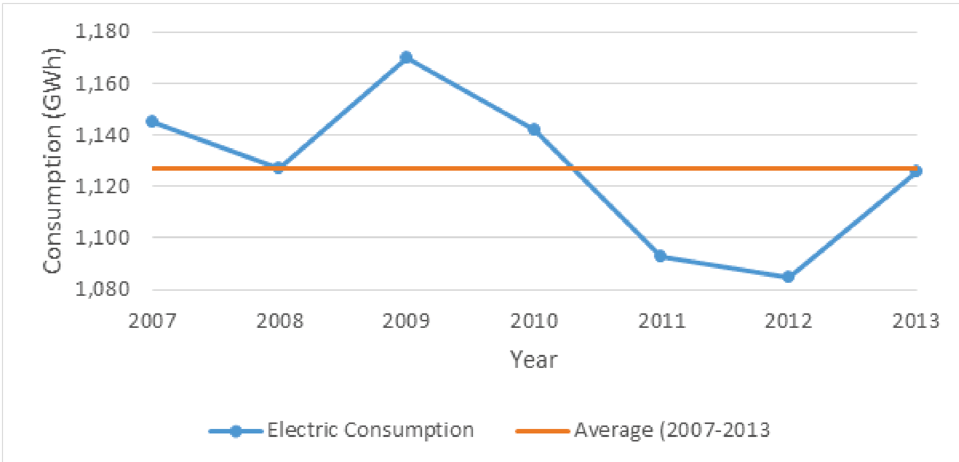
Navigant obtained updated QFER data from the CEC to support the Stage 1 updates.[107] For the Street Lighting sector inputs, Navigant relies on the total QFER data to vet the sector-wide roll up of consumption developed as part of the bottoms-up analysis approach. New electric consumption data for 2013 (the most recent year available from QFER) has been incorporated into the inputs to inform the estimate of equipment distributions of street, sign, and traffic lighting. The IOU consumption data for street lighting along with the QFER data (that represents all streets, signs, and traffic lighting) allow Navigant to parse out consumption for traffic and sign lighting.

As see in Figure C-7, the consumption data for the street lighting subsector varies. Consumption increased from 2007 to 2009, decreases from 2009 and 2012, and increases slightly in 2013. A portion of the decrease can be attributed to LED adoption, but Navigant is unable to account for all trends. Additionally, the data trend does not appear to align with IOU lamp inventory changes or growth trends (e.g., suburban sprawl). Navigant has therefore normalized the data by taking a seven year average (2007-2013) in order to mitigate the fluctuation. In turn, this average mitigates the year-over-year

[107] Ibid, QFER.

fluctuation seen in the distribution of consumption across the three subsectors: street, sign, and traffic lights.

Figure C-7: Street Lighting Sector Electric Consumption (GWh)[108]



LED Costs – Department of Energy Data

Navigant updated the cost data from the 2013 Study for LED lamps. Navigant relied on the DOE study[109] which provides a comprehensive forecast of costs and efficacies of solid-state street lighting to update the cost for LED lamps. The DOE report informed inputs in terms of normalized cost ($/klumen) and efficacy (lumens/watt). An average LED wattage of 71W from the lamp data provided by the IOUs was combined with these DOE parameters to calculate the cost per lamp for LEDs. The improvement of efficacy and reduction of LED costs in general resulted in a 22 percent decrease in LED costs from the 2013 Study. See the Emerging Technology report section for more details on how this DOE study also informed ET vectors for LEDs.

[108] Ibid, QFER data.
[109] Ibid, DOE Solid-State Lighting.

Appendix D. Codes & Standards

Table D-1: C&S Vectors

Measure Name	Sector	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Ag HVAC - Equipment (High Cost)	Agricultural	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Ag HVAC - Equipment (Mid Cost)	Agricultural	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Ag Motor Pmp - Equipment (High Cost)	Agricultural	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Ag Motor Pmp - Equipment (Low Cost)	Agricultural	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Ag Motor Pmp - Equipment (Mid Cost)	Agricultural	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Ag Motor Pmp - O&M (High Cost)	Agricultural	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Ag Motor Pmp - O&M (Low Cost)	Agricultural	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Ag Motor Pmp - O&M (Mid Cost)	Agricultural	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Ag Process Dry - Equipment (High Cost)	Agricultural	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Ag Process Dry - Equipment (Low Cost)	Agricultural	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Ag Process Dry - Equipment (Mid Cost)	Agricultural	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Ag Process Dry - O&M (High Cost)	Agricultural	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Ag Process Dry - O&M (Low Cost)	Agricultural	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Ag Process Dry - O&M (Mid Cost)	Agricultural	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Ag Process Mtr - Equipment (High Cost)	Agricultural	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Ag Process Mtr - Equipment (Low Cost)	Agricultural	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Ag Process Mtr - Equipment (Mid Cost)	Agricultural	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Ag Process Mtr - O&M (High Cost)	Agricultural	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Ag Process Mtr - O&M (Low Cost)	Agricultural	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Ag Process Mtr - O&M (Mid Cost)	Agricultural	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

Ag Refrigeration - Equipment (High Cost)	Agricultural	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Ag Refrigeration - Equipment (Low Cost)	Agricultural	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Ag Refrigeration - Equipment (Mid Cost)	Agricultural	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Ag Refrigeration - O&M (High Cost)	Agricultural	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Ag Refrigeration - O&M (Low Cost)	Agricultural	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Ag Refrigeration - O&M (Mid Cost)	Agricultural	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Ag SHWC - Equipment (High Cost)	Agricultural	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Ag SHWC - Equipment (Low Cost)	Agricultural	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Ag SHWC - Equipment (Mid Cost)	Agricultural	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Ag SHWC - O&M (High Cost)	Agricultural	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Ag SHWC - O&M (Low Cost)	Agricultural	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Ag SHWC - O&M (Mid Cost)	Agricultural	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
AppPlug - Clothes Washer (Electric)	Residential	100%	100%	100%	0%	0%	0%	0%	0%	0%	0%
AppPlug - Clothes Washer (Electric) - Emerging	Residential	100%	100%	100%	79%	79%	79%	79%	79%	79%	79%
AppPlug - Clothes Washer (Gas)	Residential	100%	100%	100%	0%	0%	0%	0%	0%	0%	0%
AppPlug - Clothes Washer (Gas) - Emerging	Residential	100%	100%	100%	79%	79%	79%	79%	79%	79%	79%
AppPlug - Computer Monitor	Commercial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
AppPlug - Computer Monitor	Residential	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
AppPlug - Desktop Computer (Com - Power Management)	Commercial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
AppPlug - Desktop Computer (Res - ES Plus)	Residential	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
AppPlug - Desktop Computer (Res - ES)	Residential	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
AppPlug - Dishwasher (Electric)	Residential	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
AppPlug - Dishwasher (Electric) - Emerging	Residential	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
AppPlug - Dishwasher (Gas)	Residential	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
AppPlug - Dishwasher (Gas) - Emerging	Residential	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

AppPlug - HP Clothes Dryer - Emerging	Residential	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
AppPlug - Occupancy Sensor Plug Strip	Commercial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
AppPlug - Recycle Refrigerator	Residential	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
AppPlug - Self-Contained Refrigerator	Residential	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
AppPlug - Self-Contained Refrigerator - Emerging	Residential	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
AppPlug - Smart Strip Home Office - Emerging	Residential	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
AppPlug - Smart Strip Home Theater - Emerging	Residential	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
AppPlug - Variable Speed Pool Pump	Residential	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
AppPlug - Vending Machine Controls	Commercial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
BldgEnv - Attic Batt Insulation	Commercial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
BldgEnv - Attic Batt Insulation	Residential	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
BldgEnv - Wall Spray On Insulation	Commercial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
BldgEnv - Wall Spray On Insulation	Residential	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
BldgEnv - Window Film	Commercial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
BldgEnv - Window Film	Residential	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
ComRefrig - Door Gasket (Reach-In Refrigerator)	Commercial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
ComRefrig - Door Gasket (Walk-In Refrigerator)	Commercial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
ComRefrig - Refrigerated Case Night Cover (Low Temp)	Commercial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
ComRefrig - Refrigerated Case Night Cover (Med Temp)	Commercial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
ComRefrig - Strip Curtain for Walk In Refrigerator	Commercial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
FoodServ - Electric Griddle	Commercial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
FoodServ - Electric Steamer	Commercial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
FoodServ - Fryer (Electric)	Commercial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
FoodServ - Fryer (Gas)	Commercial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
FoodServ - Grill to Order Cabinet	Commercial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

FoodServ - Oven (Electric)	Commercial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
FoodServ - Oven (Gas)	Commercial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
HVAC - Comprehensive Rooftop Unit Quality Maintenance	Commercial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
HVAC - Advanced Package Rooftop AC (> EER 12) - Emerging	Commercial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
HVAC - AFUE Rated Boiler (High)	Commercial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
HVAC - AFUE Rated Boiler (Standard)	Commercial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
HVAC - Chiller (Centrifugal)	Commercial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
HVAC - Chiller (Reciprocating)	Commercial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
HVAC - Chiller (Screw)	Commercial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
HVAC - Demand Controlled Ventilation	Commercial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
HVAC - Direct Evaporative Cooler	Commercial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
HVAC - Direct Evaporative Cooler	Residential	21%	21%	21%	21%	21%	21%	21%	21%	21%	21%
HVAC - EER Rated Package Rooftop AC (EER 11)	Commercial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
HVAC - EER Rated Package Rooftop HP (EER 11)	Commercial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
HVAC - Energy Management System	Commercial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
HVAC - Energy Recovery Ventilation - Emerging	Commercial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
HVAC - ET Rated Boiler (High)	Commercial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
HVAC - ET Rated Boiler (Standard)	Commercial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
HVAC - Gas Furnace	Residential	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
HVAC - Gas Furnace	Commercial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
HVAC - Gas Furnace - Emerging	Residential	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
HVAC - Repair Duct System	Commercial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
HVAC - Repair Duct System	Residential	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
HVAC - SEER Rated Package Rooftop AC (Recharge)	Commercial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
HVAC - SEER Rated Package Rooftop AC (SEER 14)	Commercial	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

HVAC - SEER Rated Package Rooftop AC (SEER 15)	Commercial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
HVAC - SEER Rated Package Rooftop HP (SEER 14)	Commercial	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
HVAC - SEER Rated Package Rooftop HP (SEER 15)	Commercial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
HVAC - SEER Rated Split System AC (Recharge)	Residential	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
HVAC - SEER Rated Split System AC (SEER 14)	Commercial	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
HVAC - SEER Rated Split System AC (SEER 15)	Commercial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
HVAC - SEER Rated Split System AC (SEER 15)	Residential	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
HVAC - SEER Rated Split System AC (SEER 18)	Residential	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
HVAC - SEER Rated Split System AC (SEER 22) - Emerging	Residential	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
HVAC - SEER Rated Split System HP (SEER 14)	Commercial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
HVAC - SEER Rated Split System HP (SEER 15)	Commercial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
HVAC - SEER Rated Split System HP (SEER 15)	Residential	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
HVAC - SEER Rated Split System HP (SEER 18)	Residential	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
HVAC - SEER Rated Split System HP (SEER 21) - Emerging	Residential	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
HVAC - Thermostat	Commercial	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
HVAC - Whole House Fan	Residential	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Ind HVAC - Equipment (Electric - High Cost)	Industrial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Ind HVAC - Equipment (Electric - Low Cost)	Industrial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Ind HVAC - Equipment (Electric - Mid Cost)	Industrial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Ind HVAC - Equipment (Gas - High Cost)	Industrial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Ind HVAC - Equipment (Gas - Low Cost)	Industrial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Ind HVAC - Equipment (Gas - Mid Cost)	Industrial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Ind HVAC - O&M (Electric - High Cost)	Industrial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Ind HVAC - O&M (Electric - Low Cost)	Industrial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Ind HVAC - O&M (Electric - Mid Cost)	Industrial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

Ind HVAC - O&M (Gas - High Cost)	Industrial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Ind HVAC - O&M (Gas - Low Cost)	Industrial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Ind HVAC - O&M (Gas - Mid Cost)	Industrial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Ind Lighting - Equipment (High Cost)	Industrial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Ind Lighting - Equipment (Low Cost)	Industrial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Ind Lighting - Equipment (Mid Cost)	Industrial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Ind Lighting - O&M (High Cost)	Industrial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Ind Lighting - O&M (Low Cost)	Industrial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Ind Lighting - O&M (Mid Cost)	Industrial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Ind MachDr - Equipment (High Cost)	Industrial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Ind MachDr - Equipment (Low Cost)	Industrial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Ind MachDr - Equipment (Mid Cost)	Industrial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Ind MachDr - O&M (High Cost)	Industrial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Ind MachDr - O&M (Low Cost)	Industrial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Ind MachDr - O&M (Mid Cost)	Industrial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Ind ProcHeat - Equipment (Electric - High Cost)	Industrial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Ind ProcHeat - Equipment (Electric - Low Cost)	Industrial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Ind ProcHeat - Equipment (Electric - Mid Cost)	Industrial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Ind ProcHeat - Equipment (Gas - High Cost)	Industrial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Ind ProcHeat - Equipment (Gas - Low Cost)	Industrial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Ind ProcHeat - Equipment (Gas - Mid Cost)	Industrial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Ind ProcHeat - O&M (Electric - High Cost)	Industrial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Ind ProcHeat - O&M (Electric - Low Cost)	Industrial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Ind ProcHeat - O&M (Electric - Mid Cost)	Industrial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Ind ProcHeat - O&M (Gas - High Cost)	Industrial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

Ind ProcHeat - O&M (Gas - Low Cost)	Industrial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Ind ProcHeat - O&M (Gas - Mid Cost)	Industrial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Ind ProcRefrig - Equipment (High Cost)	Industrial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Ind ProcRefrig - Equipment (Low Cost)	Industrial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Ind ProcRefrig - Equipment (Mid Cost)	Industrial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Ind ProcRefrig - O&M (High Cost)	Industrial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Ind ProcRefrig - O&M (Low Cost)	Industrial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Ind ProcRefrig - O&M (Mid Cost)	Industrial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Ind SHW - Equipment (High Cost)	Industrial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Ind SHW - Equipment (Low Cost)	Industrial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Ind SHW - Equipment (Mid Cost)	Industrial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Ind SHW - O&M (High Cost)	Industrial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Ind SHW - O&M (Low Cost)	Industrial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Ind SHW - O&M (Mid Cost)	Industrial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Lighting - Cold Cathode Lamp	Commercial	100%	100%	100%	0%	0%	0%	0%	0%	0%	0%
Lighting - Compact Fluorescent Fixture (Indoor)	Commercial	100%	100%	100%	0%	0%	0%	0%	0%	0%	0%
Lighting - Compact Fluorescent Fixture (Indoor)	Residential	100%	100%	100%	0%	0%	0%	0%	0%	0%	0%
Lighting - Compact Fluorescent Fixture (Outdoor)	Residential	100%	100%	100%	0%	0%	0%	0%	0%	0%	0%
Lighting - Compact Fluorescent Lamp (Basic High - Indoor)	Commercial	100%	100%	100%	0%	0%	0%	0%	0%	0%	0%
Lighting - Compact Fluorescent Lamp (Basic High - Indoor)	Residential	100%	100%	100%	0%	0%	0%	0%	0%	0%	0%
Lighting - Compact Fluorescent Lamp (Basic High - Outdoor)	Residential	100%	100%	100%	0%	0%	0%	0%	0%	0%	0%
Lighting - Compact Fluorescent Lamp (Basic Low - Indoor)	Commercial	100%	100%	100%	0%	0%	0%	0%	0%	0%	0%
Lighting - Compact Fluorescent Lamp (Basic Low - Indoor)	Residential	100%	100%	100%	0%	0%	0%	0%	0%	0%	0%
Lighting - Compact Fluorescent Lamp (Basic Low - Outdoor)	Residential	100%	100%	100%	0%	0%	0%	0%	0%	0%	0%
Lighting - Compact Fluorescent Lamp (Reflector - Indoor)	Residential	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

Lighting - Compact Fluorescent Lamp (Reflector - Outdoor)	Residential	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Lighting - Compact Fluorescent Lamp (Specialty - Indoor)	Residential	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Lighting - Compact Fluorescent Lamp (Specialty - Outdoor)	Residential	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Lighting - Exit Fixture (LED)	Commercial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Lighting - Halogen Lamp (A-Line)	Commercial	100%	100%	100%	0%	0%	0%	0%	0%	0%	0%
Lighting - Halogen Lamp (A-Line)	Residential	100%	100%	100%	0%	0%	0%	0%	0%	0%	0%
Lighting - Halogen Lamp (Reflector)	Commercial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Lighting - Halogen Lamp (Reflector)	Residential	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Lighting - High Bay HID to T5	Commercial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Lighting - Induction Fixture (Indoor)	Commercial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Lighting - Induction Fixture (Outdoor)	Commercial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Lighting - Induction Fixture (Outdoor)	Residential	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Lighting - LED Fixture (Replacing T8) - Emerging	Commercial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Lighting - LED Lamp (Basic High - Indoor) - Emerging	Commercial	100%	100%	100%	13%	13%	13%	13%	13%	13%	13%
Lighting - LED Lamp (Basic High - Indoor) - Emerging	Residential	100%	100%	100%	21%	21%	21%	21%	21%	21%	21%
Lighting - LED Lamp (Basic High - Outdoor) - Emerging	Residential	100%	100%	100%	17%	17%	17%	17%	17%	17%	17%
Lighting - LED Lamp (Basic Low - Indoor) - Emerging	Commercial	100%	100%	100%	15%	15%	15%	15%	15%	15%	15%
Lighting - LED Lamp (Basic Low - Indoor) - Emerging	Residential	100%	100%	100%	18%	18%	18%	18%	18%	18%	18%
Lighting - LED Lamp (Basic Low - Outdoor) - Emerging	Residential	100%	100%	100%	17%	17%	17%	17%	17%	17%	17%
Lighting - LED Lamp (Reflector - Indoor) - Emerging	Residential	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Lighting - LED Lamp (Reflector - Outdoor) - Emerging	Residential	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Lighting - LED Lamp (Specialty - Indoor) - Emerging	Residential	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Lighting - LED Lamp (Specialty - Outdoor) - Emerging	Residential	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Lighting - LED Plug-In Indoor Fixture - Emerging	Commercial	100%	100%	100%	6%	6%	6%	6%	6%	6%	6%
Lighting - LED Plug-In Indoor Fixture - Emerging	Residential	100%	100%	100%	7%	7%	7%	7%	7%	7%	7%

Lighting - LED Plug-In Outdoor Fixture - Emerging	Residential	100%	100%	100%	5%	5%	5%	5%	5%	5%	5%
Lighting - Light Sensor	Commercial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Lighting - Linear Fluorescent Delamping	Commercial	75%	50%	25%	0%	0%	0%	0%	0%	0%	0%
Lighting - Linear Fluorescent Delamping	Residential	75%	50%	25%	0%	0%	0%	0%	0%	0%	0%
Lighting - Linear Fluorescent Fixture (Low Wattage T8)	Commercial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Lighting - Linear Fluorescent Fixture (T8)	Commercial	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Lighting - Low Bay HID to T5	Commercial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Lighting - Night Light Fixture (LED)	Residential	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Lighting - Occupancy Sensor	Commercial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Lighting - Occupancy Sensor	Residential	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Lighting - Plug-In Fixture (Compact Fluorescent)	Commercial	100%	100%	100%	0%	0%	0%	0%	0%	0%	0%
Lighting - Plug-In Fixture (Exterior)	Commercial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Lighting - Plug-In Fixture (Exterior)	Residential	100%	100%	100%	0%	0%	0%	0%	0%	0%	0%
Lighting - Plug-In Fixture (Induction)	Commercial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Lighting - Plug-In Fixture (Linear Fluorescent)	Commercial	100%	100%	100%	0%	0%	0%	0%	0%	0%	0%
Lighting - Plug-In Fixture (Linear Fluorescent)	Residential	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Lighting - Plug-In Fixture (MH Directional)	Commercial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Lighting - Plug-In Fixture (PSMH with Electronic Ballast)	Commercial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Lighting - Plug-In Fixture (PSMH)	Commercial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Lighting - Seasonal Lighting	Residential	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Oil - Pump Controls	Mining	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Oil - Pump Motor	Mining	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Oil - Pump Motor and Controls	Mining	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Oil - Steam Boiler	Mining	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Oil - Steam Boiler Controls and Improvements	Mining	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

ProcHeat - Boiler Controls	Residential	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
ProcHeat - Boiler Draft Fan	Commercial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Service - HVAC Fault Detection & Diagnositics	Commercial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Service - Retro-Commissioning (Electric)	Commercial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Service - Retro-Commissioning (Gas)	Commercial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
SHW - EF Rated Heat Pump Water Heater	Residential	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
SHW - EF Rated Instantaneous Water Heater (Electric)	Commercial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
SHW - EF Rated Instantaneous Water Heater (Electric)	Residential	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
SHW - EF Rated Instantaneous Water Heater (Gas)	Commercial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
SHW - EF Rated Instantaneous Water Heater (Gas)	Residential	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
SHW - EF Rated Storage Water Heater (Electric)	Commercial	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
SHW - EF Rated Storage Water Heater (Electric)	Residential	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
SHW - EF Rated Storage Water Heater (Gas)	Commercial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
SHW - EF Rated Storage Water Heater (Gas)	Residential	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
SHW - EF Rated Storage Water Heater (Gas) - Emerging	Commercial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
SHW - EF Rated Storage Water Heater (Gas) - Emerging	Residential	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
SHW - ET Rated Instantaneous Water Heater	Commercial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
SHW - ET Rated Storage Water Heater	Commercial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
SHW - ET Rated Storage Water Heater - Emerging	Commercial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
SHW - Pipe and Tank Insulation	Commercial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
StreetLight - Base with Controls	Street Lighting	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
StreetLight - Induction	Street Lighting	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
StreetLight - Induction with Controls	Street Lighting	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
StreetLight - LED	Street Lighting	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
StreetLight - LED with Controls	Street Lighting	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

WholeBlg - Com NC Level 1	Commercial	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
WholeBlg - Com NC Level 2	Commercial	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
WholeBlg - Com NC Level 3	Commercial	18%	18%	5%	5%	5%	0%	0%	0%	0%	0%
WholeBlg - Com NC ZNE	Commercial	62%	62%	50%	50%	50%	37%	37%	37%	25%	25%
WholeBlg - Com RET Level 1	Commercial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
WholeBlg - Com RET Level 2	Commercial	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
WholeBlg - Low Income	Residential	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
WholeBlg - Res NC Level 1	Residential	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
WholeBlg - Res NC Level 2	Residential	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
WholeBlg - Res NC Level 3	Residential	17%	17%	0%	0%	0%	0%	0%	0%	0%	0%
WholeBlg - Res NC ZNE	Residential	100%	100%	62%	62%	62%	38%	38%	38%	38%	38%
WholeBlg - Res RET Energy Upgrade CA - Advanced Path	Residential	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
WholeBlg - Res RET Energy Upgrade CA - Basic Path	Residential	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
WholeBlg - Res RET Energy Upgrade CA - Flex Path	Residential	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

Table D-2: C&S Measures

Regulation	Code or Standard Name	Compliance Rate	Effective Date	Policy View
2005 T-20	Commercial Refrigeration Equipment, Solid Door	70%	1/1/2006	On the books
2005 T-20	Commercial Refrigeration Equipment, Transparent Door	70%	1/1/2007	On the books
2005 T-20	Commercial Ice Maker Equipment	70%	1/1/2008	On the books
2005 T-20	Walk-In Refrigerators / Freezers	91%	1/1/2006	On the books
2005 T-20	Commercial Refrigeration Equipment, Solid Door	70%	1/1/2006	On the books
2005 T-20	Refrigerated Beverage Vending Machines	37%	1/1/2006	On the books
2005 T-20	Large Packaged Commercial Air-Conditioners, Tier 1	70%	10/1/2006	On the books
2005 T-20	Large Packaged Commercial Air-Conditioners, Tier 2	70%	1/1/2010	On the books
2005 T-20	Residential Pool Pumps, High Eff Motor, Tier 1	100%	1/1/2006	On the books
2005 T-20	Portable Electric Spas	70%	1/1/2006	On the books
2005 T-20	General Service Incandescent Lamps, Tier 1	69%	1/1/2006	On the books
2005 T-20	Pulse Start Metal Halide HID Luminaires, Tier 1(Vertical Lamps)	100%	1/1/2006	On the books
2005 T-20	Pulse Start Metal Halide HID Luminaires, Tier 2 (All other MH)	100%	1/1/2008	On the books
2005 T-20	Modular Furniture Task Lighting Fixtures	70%	1/1/2008	On the books
2005 T-20	Hot Food Holding Cabinets	70%	1/1/2006	On the books
2005 T-20	External Power Supplies, Tier 1	100%	1/1/2007	On the books
2005 T-20	External Power Supplies, Tier 2	99%	7/1/2008	On the books
2005 T-20	Consumer Electronics - Audio Players	100%	1/1/2007	On the books
2005 T-20	Consumer Electronics - TVs	96%	1/1/2006	On the books
2005 T-20	Consumer Electronics - DVDs	31%	1/1/2006	On the books
2005 T-20	Water Dispensers	70%	1/1/2006	On the books
2005 T-20	Unit Heaters and Duct Furnaces	100%	1/1/2006	On the books

2005 T-20	Commercial Dishwasher Pre-Rinse Spray Valves	100%	1/1/2006	On the books
2006 T-20	Residential Pool Pumps, 2-speed Motors, Tier 2	86%	1/1/2008	On the books
2006 T-20	General Service Incandescent Lamps, Tier 2	87%	1/1/2008	On the books
2006 T-20	General Service Incandescent Lamps, Tier 2	87%	1/1/2008	On the books
2006 T-20	General Service Incandescent Lamps, Tier 2	89%	1/1/2008	On the books
2006 T-20	BR, ER and R20 Incandescent Reflector Lamps: Residential	82%	1/8/2008	On the books
2006 T-20	BR, ER and R20 Incandescent Reflector Lamps: Commercial	82%	1/8/2008	On the books
2008 T-20	Metal Halide Fixtures	95%	1/1/2010	On the books
2008 T-20	Portable Lighting Fixtures	93%	1/1/2010	On the books
2008 T-20	General Purpose Lighting -- 100 watt	88%	1/1/2011	On the books
2008 T-20	General Purpose Lighting -- 75 watt	40%	1/1/2012	On the books
2008 T-20	General Purpose Lighting -- 60 and 40 watt	85%	1/1/2013	On the books
2009 T-20	Televisions - Tier 1	98%	1/1/2011	On the books
2009 T-20	Televisions - Tier 2	85%	1/1/2013	On the books
2011 T-20	Battery charger - consumer - Tier 1	85%	2/1/2013	On the books
2011 T-20	Battery charger - large - Tier 1	85%	1/1/2014	On the books
2011 T-20	Battery charger - large - Tier 2 incremental	85%	1/1/2014	On the books
Future Title 20	Air Filter Labeling	85%	1/1/2016	Expected
Future Title 20	Commercial Clothes Dryers	85%	1/1/2016	Expected
Future Title 20	Computers - Tier 1 | Desktops, Notebooks	85%	6/1/2016	Expected
Future Title 20	Dimming Ballasts	85%	1/1/2016	Expected
Future Title 20	Electronic Displays	85%	1/1/2016	Expected
Future Title 20	Faucets (Residential)- Gas Water Heaters	85%	1/1/2016	Expected
Future Title 20	Faucets (Residential)- Electric Water Heaters	85%	1/1/2016	Expected
Future Title 20	Game Consoles (Tier 1)	85%	1/1/2016	Expected

Future Title 20	Game Consoles (Tier 2)	85%	1/1/2019	Expected
Future Title 20	Pool Pumps & Spas	85%	1/1/2016	Expected
Future Title 20	Set Top Boxes (Tier 1)	85%	1/1/2016	Expected
Future Title 20	Small Diameter Directional Lamps (Tier 1)	85%	1/1/2016	Expected
Future Title 20	Small Diameter Directional Lamps (Tier 2)	85%	1/1/2016	Expected
Future Title 20	Small Network Equipment	85%	1/1/2016	Expected
Future Title 20	Toilets (Commercial)	85%	1/1/2016	Expected
Future Title 20	Toilets (Residential)	85%	1/1/2016	Expected
Future Title 20	Urinals	85%	1/1/2016	Expected
Future Title 20	Water Meters	85%	1/1/2016	Expected
Federal	Electric Motors 1-200HP	91%	12/1/2010	On the books
Federal	Refrigerated Beverage Vending Machines	37%	8/31/2011	On the books
Federal	Commercial Refrigeration	70%	1/1/2012	On the books
Federal	Residential Electric & Gas Ranges	100%	4/9/2012	On the books
Federal	General Service Fluorescent Lamps	95%	7/14/2012	On the books
Federal	Incandescent Reflector Lamps	7%	7/14/2012	On the books
Federal	Commercial Clothes Washers	95%	1/8/2013	On the books
Federal	Residential Pool Heaters	95%	4/16/2013	On the books
Federal	Residential Direct Heating Equipment	95%	4/16/2013	On the books
Federal	Residential Refrigerators & Freezers	95%	9/15/2014	On the books
Federal	Residential Room AC	95%	6/1/2014	On the books
Federal	Fluorescent Ballasts	95%	11/14/2014	On the books
Federal	Residential Clothes Dryers	95%	1/1/2015	On the books
Federal	Residential Gas Fired Water Heaters	95%	4/16/2015	On the books
Federal	Residential Electric Storage Water Heaters	95%	4/16/2015	On the books

Federal	Residential Gas Instant Water Heaters	95%	4/16/2015	On the books
Federal	Residential Oil Fired Water Heaters	95%	4/16/2015	On the books
Federal	Small Electric Motors	95%	3/9/2015	On the books
Federal	Residential Clothes Washers (Front Loading)	95%	3/7/2015	On the books
Federal	Residential Clothes Washers (Top Loading) Tier I	95%	3/7/2015	On the books
Federal	Residential Clothes Washers (Top Loading) Tier II	95%	1/1/2018	On the books
Federal	Residential Central AC and Heat Pumps	95%	1/1/2015	On the books
Federal	External Power Supplies	95%	2/10/2016	On the books
Federal	Battery Chargers	95%	3/1/2015	Possible
Federal	Walk-in Coolers & Freezers	95%	6/5/2017	On the books
Federal	Distribution Transformers	95%	6/1/2016	On the books
Federal	Commercial Refrigeration (Cycle 2)	95%	3/27/2017	On the books
Federal	Metal Halide Lamp Fixtures	95%	2/10/2017	On the books
Federal	High-Intensity Discharge Lamps	95%	6/1/2017	Possible
Federal	General Service Fluorescent Lamps	95%	1/26/2018	On the books
Federal	ASHRAE Products (Commercial boilers)	95%	3/2/2012	On the books
2005 T-24	Time dependent valuation, Residential	0%	1/1/2006	On the books
2005 T-24	Time dependent valuation, Nonresidential	0%	1/1/2006	On the books
2005 T-24	Res. Hardwired lighting	113%	1/1/2006	On the books
2005 T-24	Duct improvement	59%	1/1/2006	On the books
2005 T-24	Window replacement	80%	1/1/2006	On the books
2005 T-24	Lighting controls under skylights	8%	1/1/2006	On the books
2005 T-24	Ducts in existing commercial buildings	75%	1/1/2006	On the books
2005 T-24	Cool roofs	75%	1/1/2006	On the books
2005 T-24	Relocatable classrooms	100%	1/1/2006	On the books

2005 T-24	Bi-level lighting control credits	79%	1/1/2006	On the books
2005 T-24	Duct testing/sealing in new commercial buildings	82%	1/1/2006	On the books
2005 T-24	Cooling tower applications	88%	1/1/2006	On the books
2005 T-24	Multifamily Water Heating	78%	1/1/2006	On the books
2005 T-24	Composite for Remainder - Res	120%	1/1/2006	On the books
2005 T-24	Composite for Remainder - Non-Res	85%	1/1/2006	On the books
2005 T-24	Whole Building - Res New Construction (Electric)	120%	1/1/2006	On the books
2005 T-24	Whole Building - Non-Res New Construction (Electric)	0%	1/1/2006	On the books
2005 T-24	Whole Building - Res New Construction (Gas)	235%	1/1/2006	On the books
2005 T-24	Whole Building - Non-Res New Construction (Gas)	0%	1/1/2006	On the books
2008 T-24	Envelope insulation	86%	10/1/2010	On the books
2008 T-24	Overall Envelope Tradeoff	141%	10/1/2010	On the books
2008 T-24	Skylighting	141%	10/1/2010	On the books
2008 T-24	Sidelighting	141%	10/1/2010	On the books
2008 T-24	Tailored Indoor lighting	462%	10/1/2010	On the books
2008 T-24	TDV Lighting Controls	0%	10/1/2010	On the books
2008 T-24	DR Indoor Lighting	0%	10/1/2010	On the books
2008 T-24	Outdoor Lighting	0%	10/1/2010	On the books
2008 T-24	Outdoor Signs	83%	10/1/2010	On the books
2008 T-24	Refrigerated warehouses	83%	10/1/2010	On the books
2008 T-24	DDC to Zone	141%	10/1/2010	On the books
2008 T-24	Residential Swimming pool	0%	7/1/2010	On the books
2008 T-24	Site Built Fenestration	83%	10/1/2010	On the books
2008 T-24	Residential Fenestration	83%	7/1/2010	On the books
2008 T-24	Cool Roof Expansion	400%	10/1/2010	On the books

2008 T-24	MF Water heating control	141%	9/1/2010	On the books
2008 T-24	CfR IL Complete Building Method	459%	9/1/2010	On the books
2008 T-24	CfR IL Area Category Method	456%	9/1/2010	On the books
2008 T-24	CfR IL Egress Control	141%	9/1/2010	On the books
2008 T-24	CfR HVAC Efficiency	141%	9/1/2010	On the books
2008 T-24	CfR Res Cool Roofs	83%	9/1/2010	On the books
2008 T-24	CfR Res Central Fan WL	83%	9/1/2010	On the books
2013 T-24	2013 T-24 - Single family NC	83%	7/1/2014	On the books
2013 T-24	2013 T-24 - Multi-family NC	83%	9/1/2014	On the books
2013 T-24	2013 T-24 - Nonres NC	83%	10/1/2014	On the books
2013 T-24	2013 T-24 - others	70%	9/1/2014	On the books
2016 T-24	2016 T-24 - Single family NC	83%	7/1/2017	Expected
2016 T-24	2016 T-24 - Multi-family NC	83%	9/1/2017	Expected
2016 T-24	2016 T-24 - Nonres NC	83%	10/1/2017	Expected
2019 T-24	2019 T-24 - Single family NC	83%	7/1/2020	Possible
2019 T-24	2019 T-24 - Multi-family NC	83%	9/1/2020	Possible
2019 T-24	2019 T-24 - Nonres NC	83%	10/1/2020	Possible
2022 T-24	2022 T-24 - Single family NC	83%	7/1/2023	Possible
2022 T-24	2022 T-24 - Multi-family NC	83%	9/1/2023	Possible
2022 T-24	2022 T-24 - Nonres NC	83%	10/1/2023	Possible

Appendix E. Behavior Analysis Data Sources

The team reviewed close to a dozen sources to inform the non- residential behavior updates. The key sources are listed below.

- » Cadmus Group Inc., Focus on Energy MEEA Training Program Evaluation, January 2015, Public Service Commission of Wisconsin
- » Opinion Dynamics Corporation, Impact Evaluation Of The California Statewide Building Operator Certification Program, February 2014, California Public Utilities Commission
- » Research Into Action, BOC-Expansion Initiative Market Progress Evaluation Report #1, April 2014 , Northwest Energy Efficiency Alliance
- » Navigant Consulting Inc., Opinion Dynamics Corporation, and Itron, Program Year 3 DCEO Building Operator Certification (BOC) Program Evaluation, May 2012, Illinois Department of Commerce and Economic Opportunity
- » Research Into Action and Energy Market Innovations (EMI), Summary Of Building Operator Certification Program Evaluations, November 2011, Consumers Energy
- » Navigant Consulting, Inc., Long Term Monitoring and Tracking Report on 2011 Activities , July 2012, Northwest Energy Efficiency Alliance
- » Navigant Consulting, Inc., Evaluation Of MN BOC Training, March 2011, Midwest Energy Efficiency Alliance and Minnesota Office of Energy Security
- » Navigant Consulting, Inc., Long Term Monitoring and Tracking Report on 2010 Activities, June 2011, Northwest Energy Efficiency Alliance
- » Navigant Consulting, Inc., Long Term Monitoring and Tracking Report on 2009 Activities, October 2010, Northwest Energy Efficiency Alliance
- » Opinion Dynamics Corporation, Evaluation Of Kansas City Power and Light's Building Operator Certification Program, September 2009, Kansas City Power and Light
- » RLW Analytics, Impact and Process Evaluation Building Operator Training and Certification (BOC) Program, September 2005, Northeast Energy Efficiency Partnerships

The team reviewed over 50 sources to inform the residential behavior updates. The key sources are listed below.

- » 2012 IPL Residential Peer Comparison EM&V Report July 11, 2013. Maria Larson. TecMarket Works, Opinion Dynamics, The Cadmus Group, Integral Analytics and Building Metrics. 2013.
- » 2013 Home Energy Report Evaluation. Bobette Wilhelm. DNV GL. 2014.
- » 2013 PG&E Home Energy Reports Program . n/a. DNV-GL. 2015.
- » 2013 PG&E Home Energy Reports Program . n/a. NEXANT. 2015.

- 2013 SCE Home Energy Reports Program. n/a. DNV-GL. 2014.
- 2013 SDG&E Home Energy Reports Program . n/a. DNV-GL. 2014.
- Analysis of PSEs Pilot Energy Conservation Project: Home Energy Reports (2011). . LBNL. .
- C3-CUB Energy Saver Program EPY5 Evaluation Report. Bill Provencher, Carly McClure. Navigant. 2014.
- CPUC. SW EA Monthly Metrics Report All IOUs Oct 2014_111314.xlsx. January 2014
- CPUC. Email from Valerie Richardson. February 2014
- Energy Efficiency / Demand Response Plan: Plan Year 2 (6/1/2009-5/31/2010). Bill Provencher. Navigant.
- Energy Efficiency / Demand Response Plan: Plan Year 3 (6/1/2010-5/31/2011). Bethany Glinsman, Bill Provencher. Navigant.
- Energy Efficiency Nicor Gas Plan Year 1, Evaluation Report: Behavioral Energy Savings Pilot. Jenny Hampton. Navigant. 2013.
- Energy Efficiency/Demand Response Plan Year 3, 2011 Evaluation Report HER Program. Randy Gunn, Stu Slote, Bill Provencher, Bethany Glinsmann, Paul Wozniak. Navigant. 2012.
- Energy Efficiency/Demand Response Plan Year 4, Evaluation Report: Home Energy Reports. Randy Gunn, Bill Provencher, Bethany Glinsmann. Navigant. 2012.
- Energy Efficiency/Demand Response Plan Year 5, Evaluation Report: Home Energy Reports. Bill Provencher, Bethany Glinsmann. Navigant. 2014.
- Energy Efficiency/Demand Response Plan: Plan Year 4 (6/1/2011---5/31/2012). Bethany Glinsman, Bill Provencher. Navigant.
- Evaluation of 2013 DSM Portfolio. Adam Thomas, Steven Keates, P.E., Jeremey Offenstein, Ph.D., Julianna Mandler, Zephaniah Davis, Jay Blatchford, Don Dohrmann, Ph.D. ADM Associates, Inc. 2014.
- Evaluation of PG&E's Home Energy Report Initiative for the 2010-2012 Program. Michael Perry, Sarah Woehleke. Freeman, Sullivan & Co. 2013.
- Evaluation of Residential Incentive Program Portfolio (May - Dec 2012). . ADM Associates. .
- Evaluation of the Home Energy Report Program. Bethany Glinsmann, Bill Provencher. Navigant. 2012.
- Evaluation of the Year 2 CL&P Pilot Customer Behavior Program (R2). NMR Group, Inc. Tetra Tech, Oversight Evaluation Contractor:, Lisa Skumatz, Skumatz Economic Research Associates, Scott Dimetrosky, Apex Analytics, Lori Lewis, AEC. NMR Group, Tetra Tech, Skumatz, Apex. 2014.
- Evaluation of Year 1 of the CL&P Pilot Customer Behavior Program (Draft) . Hunt Allcott. NMR Group, Tetra Tech, Hunt Allcott. 2013.
- Evaluation Report: OPOWER SMUD Pilot Year2. Bill Provencher. Navigant.

- Home Energy Report Program. Sharon Noell. DNV GL. 2014.
- Home Energy Reports Program, Program Year 2012 Evaluation Report. Navigant. 2013.
- Home Energy Savings Program GPY2/EPY5 Evaluation Report, Nicor Gas. Miroslav Lysyuk, Ryan Powanda, Mark Thornsjo. Navigant. 2014.
- Impact & Persistence Evaluation Report Sacramento Municipal Utility District Home Energy Report Program. Mary Wu (Pete Jacobs and Patricia Thompson contributed). Integral Analytics. 2012.
- Impact and Process Evaluation Of 2011 (Py4) Ameren Illinois Company Behavioral Modification Program (Oct 2012). Olivia Patterson, Jeevika Galhotra. ODC/Navigant. 2012.
- Impact and Process Evaluation of 2011 (Py5) Ameren Illinois Company Behavioral Modification Program (Oct 2012). Olivia Patterson, Jeevika Galhotra. ODC/Navigant. 2014.
- Impact and Process Evaluation of 2011 (Py6) Ameren Illinois Company Behavioral Modification Program (Oct 2012). Olivia Patterson, Jeevika Galhotra. ODC/Navigant. 2015.
- Massachusetts Cross Cutting Evaluation Home Energy Report Savings Decay Analysis. Hannah Arnold, Olivia Patterson, Katherine Randazzo, Amanda Dwelley. Opinion Dynamics. 2014.
- Massachusetts Cross-Cutting Behavioral Program Evaluation Integrated Report June 2013. Anne Dougherty. ODC/Navigant . 2013.
- MASSACHUSETTS CROSS-CUTTING BEHAVIORAL PROGRAM EVALUATION Volume II Final (June 2011). Anne Dougherty. ODC/Navigant. 2011.
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- Massachusetts Three Year Cross-Cutting Behavioral Program Evaluation Integrated Report July 2012. Anne Dougherty. ODC/Navigant . 2012.
- Measurement and Verification Report of Lake Country's Opower Energy Efficiency Pilot Program. . Power System Engineering. 2010.
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- National Grid Residential Building Practices and Demonstration Program Evaluation Final Results. n/a. DNV KEMA . 2014.
- New Jersey Market Assessment, Opportunities for Energy Efficiency. EnerNOC. 2013.
- Nexant, Evaluation of Southern California Gas Company's 2013-2014 Conservation Campaign Submitted to Southern California Gas Company, August 29, 2014.
- PECO Act 129 – Phase II Research Report: Program Year 5. Jenny Hampton . Navigant. 2013.
- Process Evaluation Report, EE&C Plan, Program Year Four. Anne West, Hope Lobkowicz. The Cadmus Group Inc.. 2013.

- Puget Sound Energy’s Home Energy Reports 2012 Impact Evaluation (Mar 2013). n/a. KEMA. 2013.
- Puget Sound Energy’s Home Energy Reports Program Three Year Impact, Behavioral and Process Evaluation (2012). n/a. KEMA. 2012.
- Puget Sound Energy’s Home Energy Reports Program: 20 Month Impact Evaluation. n/a. KEMA. 2010.
- PWP Home Energy Report (HER) Evaluation Results, Memo. Bethany Glinsmann, Bill Provencher. Navigant. 2013.
- PY1 EM&V Report for the Residential Energy Efficiency Benchmarking Program. Stuart Schare, Bethany Glinsman, Jenny Hampton, Robert Russell. Navigant. 2012.
- PY2 EM&V Report for the Residential Energy Efficiency Benchmarking Program. Stuart Schare, Bethany Glinsman, Jenny Hampton, Ming Xie, Amy Meyer. Navigant. 2014.
- Readying Michigan to Make Good Energy Decisions: Energy Efficiency. Michigan Economic Development Corporation / GDS Associates. 2013.
- Review of PG&E Home Energy Reports Initiative Evaluation (2013). n/a. KEMA. 2013.
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- Smart Energy Manager Program 2013 Evaluation Report. Bethany Glinsmann, Bill Provencher, Brent Barkett. Navigant. 2014.
- Summit Blue Evaluation Report - SMUD. Bill Provencher . Navigant.
- Update to the Colorado DSM Market Potential Assessment (Revised). KEMA. 2013
- Utah Home Energy Reporting Program. Bill Provencher, Bethany Glinsmann, Argene McDowell, Amanda Bond, Dave Basak. Navigant. 2014.
- Verification of Hawaii Energy 2011 Programs. n/a. Evergreen Economics. 2012.
- Washington Home Energy Reporting Program 18 month evaluation report. Bill Provencher, Bethany Glinsmann, Argene McDowell, Amanda Bond, Dave Basak. Navigant. 2014.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769.	)	Rulemaking 14-08-013 (Filed August 14, 2014)
And Related Matters	)	Application 15-07-002 Application 15-07-003 Application 15-07-006
(NOT CONSOLIDATED)		
In the Matter of the Application of PacifiCorp (U901E) Setting Forth its Distribution Resource Plan Pursuant to Public Utilities Code Section 769.	)	Application 15-07-005 (Filed July 1, 2015)
And Related Matters	)	Application 15-07-007 Application 15-07-008

CERTIFICATE OF SERVICE

I hereby certify that I have this day served a copy of the foregoing **ADDENDA TO REVISED DISTRIBUTED ENERGY RESOURCE ASSUMPTIONS AND FRAMEWORK DOCUMENT OF PACIFIC GAS AND ELECTRIC COMPANY (U 39 E), SAN DIEGO GAS & ELECTRIC COMPANY (U 902 E), AND SOUTHERN CALIFORNIA EDISON COMPANY (U 338 E)** on all parties identified in R.14-08-013, A.15-07-002, A.15-07-003, A.15-07-005, A.15-07-006, A.15-07-007, and A.15-07-008 by electronic mail, U.S. mail for those parties without an email address and by Federal Express to the assigned Administrative Law Judge.

Dated at San Diego, California, this 28th day of June, 2017.

<u>/s/ Darleen Evans</u>
Darleen Evans

CPUC Home

CALIFORNIA PUBLIC UTILITIES COMMISSION
Service Lists

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