REPORT

2014 Load Impact Evaluation of the California Statewide Permanent Load Shifting Program

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Abstract

This evaluation documents the ex ante load impact analysis and results for the California Statewide Permanent Load Shifting (PLS) program at Pacific Gas & Electric (PG&E), Southern California Edison (SCE) and San Diego Gas & Electric (SDG&E). The 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. The statewide PLS program design was finalized and adopted by the CPUC in May 2013.[1] Because of the long lead time involved in moving from completing an application to actual PLS installations, there are no current program installations on which to base ex post impact estimates for 2014. As such, this evaluation focuses on the 2015–2025 ex ante load impact estimates. As of January 2015, the utilities had a total of 11 active applications. The ex ante impact estimates rely on information in these applications to improve upon the analysis that was done for the 2013 program year evaluation, which had fewer applications in the pipeline. Nonetheless, this year's forecast is still uncertain and relies on assumptions about impacts and further enrollment in the program, which have a high degree of uncertainty. If future ex post evaluations show that the PLS-TES technology works differently than expected or if enrollment proceeds at an unexpected pace, this forecast may not reflect the load impacts that the PLS program ultimately delivers. This evaluation attempts to reflect this high degree of uncertainty in the forecast by providing low case, base case and high case enrollment and load impact scenarios. In the base case scenario for the 2018 Utility-specific August monthly system peak day under 1-in-10 year weather conditions, the program is expected to deliver a 4.1 MW load impact for PG&E, a 8.1 MW load impact for SCE and a 3.4 MW load impact for SDG&E, totaling 15.6 MW statewide.

[1] CPUC Resolution E-4586 issued on May 9, 2013.

1 Introduction

This evaluation documents the ex ante load impact analysis and results for the California Statewide Permanent Load Shifting (PLS) program at Pacific Gas & Electric (PG&E), Southern California Edison (SCE) and San Diego Gas & Electric (SDG&E). The statewide PLS program design and rules were finalized and adopted by the California Public Utility Commission (CPUC) in May 2013.[2] Because of the long lead time involved in moving from completing an application to actual PLS installations, there are no current program installations on which to base ex post impact estimates for the 2014 program year (PY2014). As such, this evaluation focuses on the 2015–2025 ex ante load impact estimates. Under the Statewide PLS program, utility customers are incentivized to install Thermal Energy Storage (TES) systems, which either eliminate or reduce peak period electric load for cooling by shifting energy use to off-peak periods. Shifting daily cooling loads to off-peak periods benefits the grid and distribution systems for regions with peaking characteristics that mirror those of the grid, and can reduce customer bills relative to applicable time-varying rates. For installed TES technology, the total incentive is calculated as a multiple of the peak period load (kW) that is shifted to off-peak periods and equals $875/kW, with a cap of $1.5 million per project.

1.1 Background

Prior to this statewide program, each of the three IOUs conducted PLS programs similar to the currently proposed program, but with different incentive levels and technologies. These programs arose out of CPUC Decision (D.) 06-11-049, Order Adopting Changes to 2007 Utility Demand Response Programs, which was part of the 2006–2008 Demand Response Application (A.) 05-06-006, et. al. This Decision, among other things, ordered the IOUs to pursue requests for proposals and bilateral arrangements for PLS installations to promote system reliability during summer peak-demand periods. A four-year PLS pilot program was approved for all the IOUs from 2008–2011. The details of those pilot programs are not revisited here; it should just be noted that each IOU has recent experience with PLS programs and technologies, although the proposed program design is new and stems from lessons learned and a different Decision.

In November 2010, a Statewide PLS Study, authored by Energy + Environmental Economics (E3) and StrateGen, provided information to the utilities for use in developing a new proposed PLS program. On April 30, 2012, D.12-04-045 ordered the utilities to work collaboratively to develop and propose a standardized, statewide PLS program. As part of the PLS program design process, the utilities incorporated the findings from the Statewide PLS Study into the 2012–2014 PLS program design. On July 30, 2012, the utilities submitted a joint PLS program design proposal to the Commission Staff. The Commission Staff sought feedback from interested parties by facilitating a PLS Workshop that was held on September 18, 2012. As a result of the PLS Workshop and comments received from interested parties, Energy Division (ED) provided the utilities with program design feedback on November 13, 2012. The IOUs incorporated ED's feedback in their final version of the program design proposal submitted on January 14, 2013. The most noteworthy ED input resulted in limiting eligibility to thermal energy storage technologies for cooling. On May 9, 2013, Resolution E-4586 adopted the PLS program rules, budget and implementation details proposed by the IOUs, with modifications.

[2] CPUC Resolution E-4586 issued on May 9, 2013.

In May of 2014, the CPUC issued a decision[3] to fund 2015 and 2016 as bridge funding years. This decision authorized a total program budget of $10M for PG&E, $9.3M for SCE and $2M for SDG&E. The incentive portion of the budget was $9M for PG&E, $6.5M for SCE and $2M for SDG&E. On December 4, 2014, D.14-12-024 stated that 2016-17 will also be a bridge year but there was no information regarding details on program budgets. A ruling by the assigned ALJ in this proceeding will be issued in 2015 to initiate the process to authorize a 2017 bridge funding period. It should be noted that the utilities are currently working to request funding for the next bridge funding cycle. However, enrollment forecasts for future funding cycles will not be integrated into the load impact analysis until the budgets are formally authorized by the CPUC.

1.2 Key Considerations for Program Year 2014 Load Impact Forecast

As previously noted, there are no current PLS program installations to produce ex post impact estimates for PY2014 or to use for estimating ex ante impacts. Despite that, the ex ante load impact estimates in this document conform to the timing and requirements of the CPUC Demand Response Load Impact Protocols for non-event based programs.[4] Since the program rules have been finalized and customer feasibility studies and applications have already been submitted, the ex ante impact estimates rely on information in these pipeline applications to improve upon the analysis that was done for the PY2013 evaluation, which had fewer applications in the pipeline. Nonetheless, this year's forecast still relies on numerous assumptions about impacts and further enrollment in the program, which have a high degree of uncertainty. If future ex post evaluations show that the PLS-TES technology works differently than expected or if enrollment proceeds at an unexpected pace, this forecast may not reflect the load impacts that the PLS program ultimately delivers. For example, this forecast assumes that each utility receives a certain number of PLS program applications for low, base case and high scenarios. However, these assumptions carry a high degree of uncertainty because projecting uptake of any utility program is inherently uncertain. This uncertainty is compounded by the fairly high initial capital investment and custom nature of each installation. The actual number of applications that each utility receives could be quite different than these projections.

The current PLS program design specifies a set of measured data to be collected from participants to optimize TES system performance and enable load impact evaluation. In future years, these measurements will be the basis for the ex post and ex ante impact evaluations. For this evaluation, ex ante estimates rely, in part, on information contained in the feasibility studies and applications submitted by the end of 2014. These applications do not exhaust the program budgets for each utility. As such, ex ante estimates associated with the remaining budget were based on a method similar to the one used in last year's evaluation, which estimated impacts by dividing the program budgets expected to be spent by the incentive amount per kW that the utilities pay for PLS investments. Estimates from program managers and evaluation, measurement and verification (EM&V) staff on budget scenarios, combined with knowledge of the proposed rules of the program and building simulation modeling, provided the foundation for the analysis. As the PLS program evolves and actual PLS-TES installations come online over the next few years, evaluators will gradually phase out the assumptions-driven

[3] CPUC D.14-05-025 issued on May 19, 2014

[4] CPUC D.08-04-050 issued on April 28, 2008 with Attachment A.

approach and transition to a data-driven approach, which will reduce the uncertainty of future ex ante load impact estimates.

1.3 Program Overview

The PLS program provides a one-time incentive payment ($875/kW shifted) to customers who install qualifying PLS-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 the program application, approval and verification process, which includes all of the stages that are required for customers to apply for and receive a verified incentive amount. These stages are:

1. Customer submits complete application;
2. Customer submits feasibility study;
3. IOU reviews feasibility study prior to approval;
4. IOU conducts pre-installation inspection, including pre-installation M&V, and, if customer passes, approves application and sets aside incentive funds;
5. IOU and customer sign agreement (SCE only);
6. Customer submits project design; customer installs PLS-TES system;
7. Customer submits commissioning report;
8. IOU reviews commissioning report and conducts post-installation inspection, tests, cost and any other verifications; and
9. Customer receives final PLS technology incentive.

After submitting an application, participating customers must provide, in advance of installation, a feasibility study prepared by a licensed engineer. This study must include an estimated cooling profile for each hour for a year based on building simulation models and input about building specifications, regional temperatures, occupancy and other inputs. Both retrofit and new construction customers are subject to the energy modeling process unless utility approved cooling usage data is available.

The total incentive amount is determined using a customer’s peak load shift on their maximum cooling demand day (based on the on-peak hours). A conversion factor is used to convert the cooling load shift tons to electricity load shift (kW) for both full and partial storage systems. The incentive levels for the program are $875/kW for all IOUs.

The incentive payments are intended to offset a portion of the cost of installation, thereby making the system more attractive financially. Under the program rules, the incentive cannot exceed 50% of the total project cost or $1.5 million. For each customer, the incentive is the lessor of (1) the incentive reservation amount calculated from the approved feasibility study and post-installation approval; (2) 50% of the actual final installed project cost; or (3) $1.5 million. In addition, customers are required to be on a time-of-use rate and provide trend data to the IOU's about their TES system for the first five years after installation. In the participation component of the program, customers are required to run their TES system on summer weekdays for five years after installation and submit monitored system data to the IOU. The systems are expected to have a lifetime of about 20 years.

The current incentive budgets from the '15-'16 Bridge funding cycle are $9 million for PG&E, $6.5 million for SCE and $2 million for SDG&E. At a minimum, these incentive budget amounts can be interpreted to represent an upper limit on the amount of peak period shifting from new applications that the program could ultimately provide as a result of funding during this program cycle.

Customers are required to shift load by running the TES system on weekdays during summer months, which are defined slightly differently for each utility. Table 1-1 shows the On peak periods and summer months for each utility, as approved in the Statewide PLS Program Proposal.[5] PLS program participants are encouraged to shift load during non-summer months to maximize their energy bill savings.

Table 1-1 On-peak Periods for Each Utility

Utility	Summer Months	On-peak Hours
PG&E	May 1–October 31	12–6 PM
SCE	June 1–September 30	12–6 PM
SDG&E	May 1–October 31	11 AM–6 PM

1.4 Current PLS Program Status

Table 1-2 provides the PLS program status by utility and by stage in the PLS application and verification process. As of January 2015, the utilities had 11 active applications that are likely to move forward in the verification process. Since these applications have already been received, they are referred to as identified projects in the ex ante forecast. If these 11 customers successfully install a PLS-TES system, these installations are expected to provide 9.7 MW of total load shift, resulting in incentives of around $6.9 million being spent across the three utilities. However, as these customers move through the verification process, the load shift amount is likely to change, so the 9.7 MW total load shift amount is simply an indicator based on the most recently available information. SCE has received a total of nine applications, with four applications either temporarily or permanently being withdrawn. The remaining five active applications all have completed feasibility studies. PG&E has approved four applications; however one application has since been withdrawn. The remaining three active applications all have completed feasibility studies. SDG&E received three applications, and all projects have completed the feasibility study submission stage. While this year's PLS evaluation benefits from

[5] 2012–2014 Statewide Permanent Load Shifting Program Proposal. July 30, 2012. Jointly proposed by: Pacific Gas and Electric, San Diego Gas & Electric and Southern California Edison Company.

this information on applications that have been received, it is important to recognize that there are six or seven time-consuming stages from the time an application is submitted by the customer to the time when the installation comes online. All of these stages are illustrated in Table 1-2. It can take from one to two years for applications to go through all of the stages and result in an installation depending on the size and complexity of the project. Based on the current applications, the time period for each project (application) is expected to vary with the size of the PLS-TES installation, from 8 months for small projects to 24 months for large projects. Therefore, the forecast for these identified projects is still uncertain, as the kW load shift can change during the verification process and customers may choose not to continue through the process.

Table 1-2: PLS Program Status by Utility and Stage in Verification Process (as of January 2015)[6]

Stage #	Stage Description	PG&E Totals			SCE Totals			SDG&E Totals		
		Apps	Incentive	kW	Apps	Incentive	kW	Apps	Incentive	kW
1	Customer submits complete application									
2	Customer submits feasibility study				1	[redacted]	[redacted]	3	[redacted]	[redacted]
3	IOU reviews feasibility study and approves application	3	[redacted]	[redacted]	2	[redacted]	[redacted]			
4	IOU conducts pre-installation inspection and sets aside incentive funds									
5	IOU and customer sign agreement (SCE only)				2	[redacted]	[redacted]			
6	Customer submits project design and installs PLS-TES system									
7	Customer submits commissioning report									
8	IOU reviews commissioning report and conducts post-installation inspection, tests and cost verifications									
9	Customer receives final PLS program incentive									
Total		**3**	[redacted]	[redacted]	**5**	[redacted]	[redacted]	**3**	[redacted]	[redacted]

6 In instances where the customer information does not satisfy the 15/15 aggregation rule for non-residential customers or the 100 aggregation rule for residential customers under D.14-05-016, that information has been redacted from the public version, and are making a confidential version available to the Commission's Energy Division.

1.5 Report Organization

The remainder of this report proceeds as follows. Section 2 summarizes the methodology used for the evaluation. Section 3 provides a summary of key assumptions and the resulting enrollment forecast. Section 4 provides the ex ante load impact estimates by utility. Section 5 includes recommendations for future evaluations. Appendix A summarizes the methodology for developing the ex ante conversion factors, which are key inputs for the analysis. These ex ante conversion factors were recalculated for this year's evaluation to accommodate the new CAISO peak period reporting requirements. Finally, Appendix B describes the analytical approach for the building simulation modeling used for PG&E's identified projects.

2 Methodology

Although the statewide PLS program currently has 11 applications in the pipeline, no program-funded TES installations have been completed that would allow for modeling load impacts. Each utility had a pilot PLS program from 2008 through 2011, but the design of the Pilots differed from the current program design, therefore the PLS-TES installations completed under the Pilots cannot be used as the basis for forecasting load impacts for this program. To produce load impact estimates for the PY2014 PLS evaluation, Nexant relied on assumptions from the program managers and EM&V staff at each utility to forecast the budget scenarios, timing of when projects would become operational, and additional aspects related to the number, size, and geographic distribution of future projects. These assumptions have a high degree of uncertainty because projecting uptake of any utility program is inherently uncertain, especially when there are multiple stages in the application and verification process that may require up to 18 months or more to complete.[7] To date, there is not enough data to predict how many projects will be installed, how big those projects will be, where they will be located or when they will start up. This uncertainty is compounded by the fairly high investment cost and custom nature of each installation. Without a detailed assessment of any given site, it is hard to know whether it would be a good candidate for PLS-TES installation.

The 2014 evaluation attempted to reflect this high degree of uncertainty in the forecast by providing low case, base case and high case enrollment and load impact scenarios. The base case is the expected[8] value as drawn from discussions that Nexant had with utility program staff. The low case is a forecast in which PLS program uptake is around 50% lower and the high case is around 65% higher than the base case, for PG&E. For SCE, the low case is a forecast in which PLS program uptake is around 40% lower and the high case is around 40% higher than the base case. Finally, for SDG&E the low case is a forecast in which PLS program uptake is around 20% lower and the high case is around 20% higher than the base case. Under the high scenario, customer enrollment would significantly exceed the current best guesses of utility program staff. Similarly, under the low scenario, enrollment would fall short of utility expectations. Even this range may not fully cover the outcomes that the program could experience. In a case like this with such high uncertainty, it is likely that other stakeholders may make different projections or consider different assumptions reasonable. To allow other stakeholders to understand how different assumptions may produce different values, this evaluation is as transparent as possible about all of the assumptions and about how the assumptions lead to the reported load impact forecasts. Therefore, a concise summary of assumptions that drove the PY2014 evaluation by utility is provided in Section 3. All of the assumptions are based on the most recent information on program enrollment and the current status of projects that have been identified and are in the application/verification stages of the process.

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[7] The steps in the application and verification process are described in detail in the Statewide PLS Program Handbook (September, 2014).

[8] Note that these "expected values" are not expected values in a statistical sense. They are literally just what utility program staff express as reasonable expectations. The uncertainty expressed in the high and low values are also just opinions, not statistical measurements.

This evaluation forecasts load impacts for two different types of projects— *identified* (those for which customers have completed an application or feasibility study) and *unidentified* (applications that are expected to be submitted during the current funding cycle). Applications are submitted by potential PLS participants to initiate their enrollment in the program. Each application includes an initial estimate of the proposed PLS-TES installation's load shifting capacity. Feasibility studies are more in-depth analyses conducted by qualified engineers and include a technical and cost analysis of the proposed project. Completion of a feasibility study is the next step in the PLS approval process after the initial application has been submitted and approved. As of this writing, a total of 16 applications have been received by the 3 IOUs, 5 have been withdrawn, and 11 projects have completed feasibility studies.

For identified projects, the ex ante load impacts were allocated to specific local capacity areas[9] (LCAs) because the location of the PLS-TES system installation was known. While this information on where identified projects will be installed reduces some uncertainty in the forecast, there is still substantial uncertainty regarding whether the project will successfully go through the entire verification process given that, as of January 2015, no projects have completed the actual installation stage and started operation. The identified projects also have an expectation of the installation date (either in the application or the feasibility study, if available), but those dates may change throughout the verification process.

Load impacts for unidentified projects are based on assumptions developed with the utility PLS program managers and EM&V staff, as discussed above. The forecast of unidentified projects is based on the number of applications that are expected to be submitted by the end of 2016, when "bridge" funding for the PLS program's incentives expires. In previous evaluation years, utilities expected the bridge funding to end in 2014. The "bridging" budget has now been approved for 2015–2016. On December 4, 2014, D.14-12-024 stated that 2016-17 will also be a bridge year but there was no information regarding details on program budgets. A ruling by the assigned ALJ in this proceeding will be issued in 2015 to initiate the process to authorize a 2017 bridge funding period. The budgets for each IOU have been updated accordingly, based on the recent regulatory decisions.

For unidentified projects, the number and size of the installations have been estimated for a range of scenarios based on an expected[10] percentage of each utility's incentive budget that will be spent (similar to last year's approach). However, additional assumptions are needed to estimate the pace of project startups and the allocation of load impacts across different LCAs, given load impacts are location and weather dependent.

Because the number and size of <u>identified</u> projects varies between each IOU, the approach used to evaluate program impacts was tailored to the amount of information that was available for each IOU. Primarily, the number and diversity of applications determines the methodology used to generate load impacts for identified projects. The methodology for determining load impacts from <u>unidentified</u> projects was uniform across the three IOUs, although the specific assumptions for these impacts did vary and were partially informed by the applications that each IOU had received.

[9] LCA is the CAISO-defined term that represents each transmission-constrained load pocket in the California IOU service territories.

[10] Expected in a statistical context, such as the "expected" value.

The following subsections describe the methodology that was used to estimate load impacts for both identified and unidentified projects.

2.1 Identified Projects

The PY2014 PLS program evaluation used two different methodologies for estimating ex ante load impacts for identified projects. For PG&E, Nexant updated the building simulation modeling that was used in the 2013 evaluation to reflect the new ex ante weather data that was developed this year (see Section 2.3 for further detail). For SCE and SDG&E, Nexant used an approach that was similar to that for unidentified projects, except that the installation date and location were based on each specific project.

2.1.1 PG&E Approach

PG&E had three active applications at the time the evaluation was conducted, with a wide range of expected peak load shifts. All three of the projects use TES for process cooling loads or process cooling combined with space cooling. These process cooling loads may be quite different from the typical space cooling loads for which the ex ante conversion factors were designed to be used. It is important to note that the conversion factors were developed with building simulation models of space cooling installations. While space cooling loads exhibit significant seasonality due to temperature variation, process cooling loads may vary seasonally by temperature and changes in the underlying production process. For example, agricultural customer process cooling loads tend to follow the harvest schedule in addition to being temperature sensitive. Given the unexpected nature of these projects and the fact that a single project is expected to deliver a large portion of the load shift, PG&E chose to use building simulation modeling to estimate the ex ante load impacts for identified projects.

For this building simulation modeling work, the evaluation team used the Quick Energy Simulation Tool (eQUEST), which is a software package designed in collaboration with the Department of Energy (DOE) and Lawrence Berkeley National Laboratory (LBNL).[11] This software is used extensively throughout the industry to simulate building energy use for a wide variety of climates, building types and cooling technologies (including various TES designs). The analytical approach for the building simulation modeling is described in Appendix B.

2.1.2 SCE and SDG&E Approach

At the time of the evaluation, SCE had five active projects and SDG&E had three. All eight of these projects had reached the feasibility study stage in the application and verification process. The projects range in size from approximately 400 kW up to 1 MW. Given the relatively small size of these projects and the large time commitment that is required for building simulation modeling (even without a site visit), SCE and SDG&E decided not to use building simulation modeling to forecast the ex ante load impacts for these projects. Instead of using building simulation modeling, the ex ante conversion factors (discussed in the next report section) were used to convert the expected load shift from the application/feasibility study to ex ante weather conditions. This methodology is nearly identical to Step 2 and Step 3 in the methodology used for unidentified projects discussed in Section 2.2, except that the incentive amount was taken

11 eQUEST, <http://www.doe2.com/equest/>

from the latest available information for that project (the application or feasibility study). In addition, considering that the location and installation date were provided in the application for identified projects, the forecast for SCE and SDG&E identified projects incorporates this information by having the project come online on the expected installation date and by assigning the ex ante load impacts for that project to the customer's LCA.

2.2 Unidentified Projects

This year's methodology for unidentified projects was similar to that used for the PY2013 ex ante PLS evaluation, as they both attempt to quantify load impacts for customers whose building characteristics, location, project timing and load patterns are unknown. As in last year's PLS evaluation, because the main uncertainty was the number and size of projects that will be included in the program, a range of scenarios has been generated for each IOU.

Figure 2-1 summarizes the three-stage methodology for estimating ex ante load impacts for unidentified PLS projects.

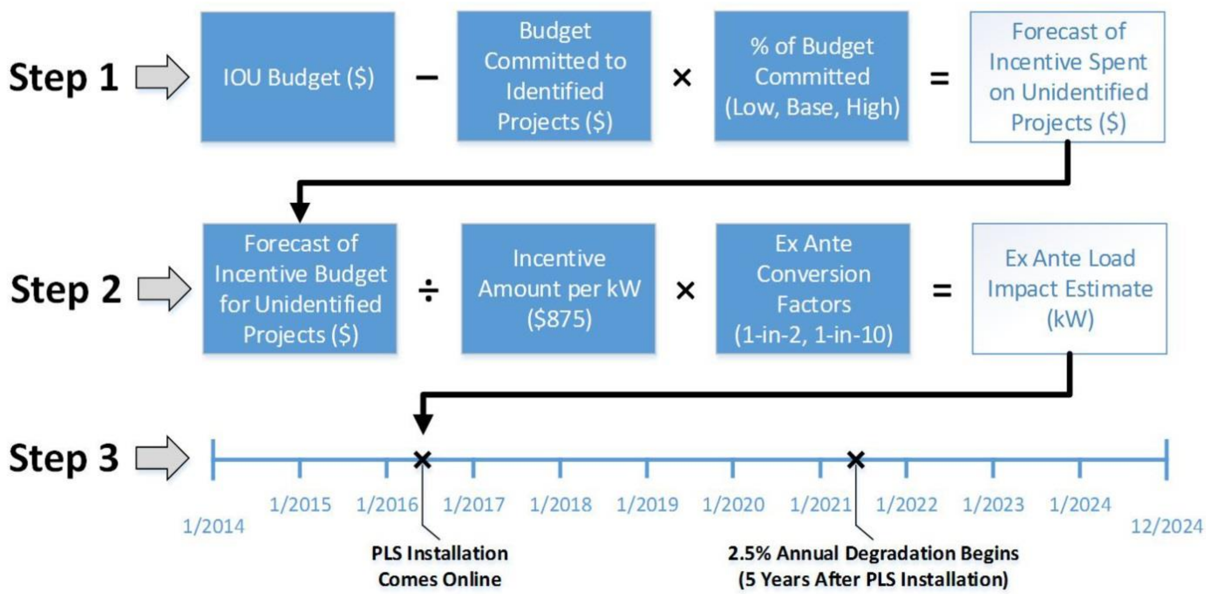
- **Step 1** involved forecasting the available amount of incentive dollars that will be spent on unidentified projects for each IOU. The first key input for this calculation was the total PLS incentive budget for each IOU. The budget that has been committed to identified projects was subtracted from the total incentive budget amount. Then, the remaining budget for unidentified projects was multiplied by the percentage of each IOU's budget that will be committed to projects by the end of 2016, under the low, base case and high scenarios.[12] This produced the forecast of incentives available to be spent on unidentified projects.
- **Step 2** converted the incentive dollar forecast into the ex ante load impact estimates. To do this, the forecast of incentive dollars spent on unidentified projects was divided by the incentive amount per kW load shift ($875/kW). This kW load shift amount represents the peak load shift[13] that can be expected under hot, maximum cooling load, weather conditions. The kW load shift was multiplied by the ex ante conversion factors, which converted the load shift under the incentive payment, maximum cooling load and weather conditions to the ex ante load impact estimates for monthly system peak days and average weekdays under 1-in-2 year and 1-in-10 year weather conditions (as per the California DR Load Impact Protocols). The conversion factors were re-estimated for the PY2014 evaluation based on updated building simulation models and newly developed 1-in-2 and 1-in-10 year weather data that address the new requirement for reporting results for the CAISO system peak in addition to the IOU system peak.

12 The percent budget commitment does not necessarily reflect the amount that will ultimately be spent, since some projects may drop from the PLS program prior to installation (for instance, if the feasibility study indicates that the project would not be cost-effective for the customer). To account for this, the forecast assumes a drop off rate between projects committed and projects actually installed. In the PY2014 evaluation, the assumed drop off rate was 10%.

13 This peak load shift value is the amount of demand shifting that each utility expects to pay incentives for. This means that these are expected output from the model used in the engineering feasibility study for each site. Although we do not know with certainty what conditions the engineers performing the study used to represent peak yearly conditions, the new building simulation models were calibrated such that the 1-in-10 peak day conditions for the hottest month in each LCA represented the maximum cooling load conditions. Because the models creating the conversion factors used the weather from the hottest 1-in-10 peak day to set the maximum cooling load, and consequently the maximum peak load shift, the hottest 1-in-10 peak weather day can also be used as a proxy for weather conditions under which the incentive would be calculated. See Appendix A for additional discussion.

- **Step 3** forecasts when each PLS-TES installation is expected to come online based on slightly different assumptions for each utility (described below). The time between when an application is received and when the installation and verification are completed varies from 8 to 24 months, so projects are not expected to come online until 2016 or later. Over time, the load shifting capacity of the PLS-TES technologies is expected to degrade as the system ages. The forecasts assume that five years after each forecasted PLS-TES installation, the ex ante impacts begin to degrade at a rate of 2.5% per year. This assumption was made in consultation with program managers and it is consistent with last year's evaluation.

Figure 2-1: Methodology for Estimating Ex Ante Load Impacts of Unidentified PLS Projects



The ex ante conversion factors were used to convert the load shift under the incentive payment, maximum cooling load and weather conditions to the load shift that can be expected under the various ex ante temperature scenarios. The ex ante temperature scenarios include the monthly system peak days and average weekdays under 1-in-2 year and 1-in-10 year weather conditions for the utility specific and CAISO peak. Essentially, the conversion factors facilitate the estimation of the PLS-TES load impacts under a variety of different weather conditions with ease and efficiency. The methodology for developing the conversion factors is described in Appendix A. In the appendix, Nexant provides evidence that it is not necessary to know the specific building characteristics, and that conversion factors may be used for this evaluation. The analysis shows that relative usage values across different weather conditions are basically insensitive to building characteristics, and the ratio for a given ex ante condition hardly changes as the building characteristics vary substantially. This relationship is a critical factor in the evaluation, and the current conversion factor approach would need to be modified if this weren't the case.

It is important to note that these conversion factors were developed with building simulation models of space cooling installations. Some of the applications that have been received thus far also include process cooling installations, which have load profiles that frequently differ from the typical space cooling profile. Unfortunately, the process cooling installations do not make good candidates for generalized modeling because they are highly customized by industry and location; in addition, while space cooling loads exhibit significant seasonality due to temperature variation, process cooling loads may vary seasonally by temperature and changes in the underlying production process. For example, agricultural customer process cooling loads tend to follow the harvest schedule in addition to being temperature sensitive. The weather sensitivity of the currently modeled process cooling applications was analyzed, and the range of sensitivity in terms of the percentage difference in cooling load between 1-in-2 and 1-in-10 monthly peak days exhibit similar upper and lower limits to commercial AC cycling programs. For the sake of simplicity, lack of generalizability of the process cooling installations and similarity in weather sensitivity ranges, space cooling building simulation models were used to develop the conversion factors for both space cooling and process cooling installations.

The forecast of incentive dollars spent on unidentified projects was used to estimate PLS program enrollment, which is defined as the number of PLS-TES installations that have come online. Before a project comes online, customers must go through the application and verification process, during which some customers may drop off. Therefore, customers are not defined as enrolled until their PLS-TES installation has come online. Nonetheless, for each IOU, the applications that have been received were used to inform assumptions about the following:

- Peak load shift of typical unidentified projects;
- Number of projects of each size; and
- Expected project installation and verification timeline (the time between when an application is received and when the installation and verification are completed).

These assumptions are IOU-specific and were informed by the current applications for identified projects. Section 3 provides a summary of the assumptions from the PY2014 evaluation. The PY2014 evaluation refined these assumptions based on the most recent information on budget, program enrollment, the current status of identified projects and the recently revised and adopted Statewide PLS Program Handbook (September 2014).

Finally, because local weather conditions influence the load shift that is actually experienced, the ex ante load impacts are dependent on the specific geographic region in which an installation is located. As such, it was necessary to allocate the unidentified projects to LCAs within each utility's service area. Without any information on where these projects will actually be located, the aggregate peak load shift was allocated to each LCA in proportion to the distribution of C&I customers with annual maximum demand greater than 500 kW for PG&E and 1 MW for SCE located in each LCA. The 500 kW and 1 MW thresholds were determined based on the existing pool of applications. SDG&E has only a single LCA, so no population weighting was necessary. Considering that the utilities have received applications from customers that are located in LCAs that are not usually associated with having high cooling load, the expectation regarding where these PLS-TES installations will be located is unclear. Essentially, with process cooling being eligible for PLS program incentives, the program is viable in many different climates, as the current applications have shown.

2.3 Estimating Ex Ante Weather Conditions

The CPUC Load Impact Protocols[14] 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). Since 2008, the IOUs have based ex ante weather on system operating conditions specific to each individual utility. 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 each IOU. While the protocols are silent on this issue, a letter from the CPUC Energy Division to the IOUs dated October 21, 2014 directed the utilities to provide impact estimates under two sets of operating conditions starting with the April 1, 2015 filings: one reflecting operating conditions for each IOU and one reflecting operating conditions for the CAISO system.

In order to meet this new requirement, California's IOUs contracted with Nexant to develop 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 this year 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 IOUs.[15]

The extent to which utility-specific ex ante weather conditions differ from CAISO ex ante weather conditions largely depends on the correlation between individual utility and CAISO peak loads. Figure 2-2 shows the correlations between each of the three California investor-owned utilities' daily peaks and CAISO system-wide daily peaks. Because the focus was 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, leading 200 observations per utility).

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 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).

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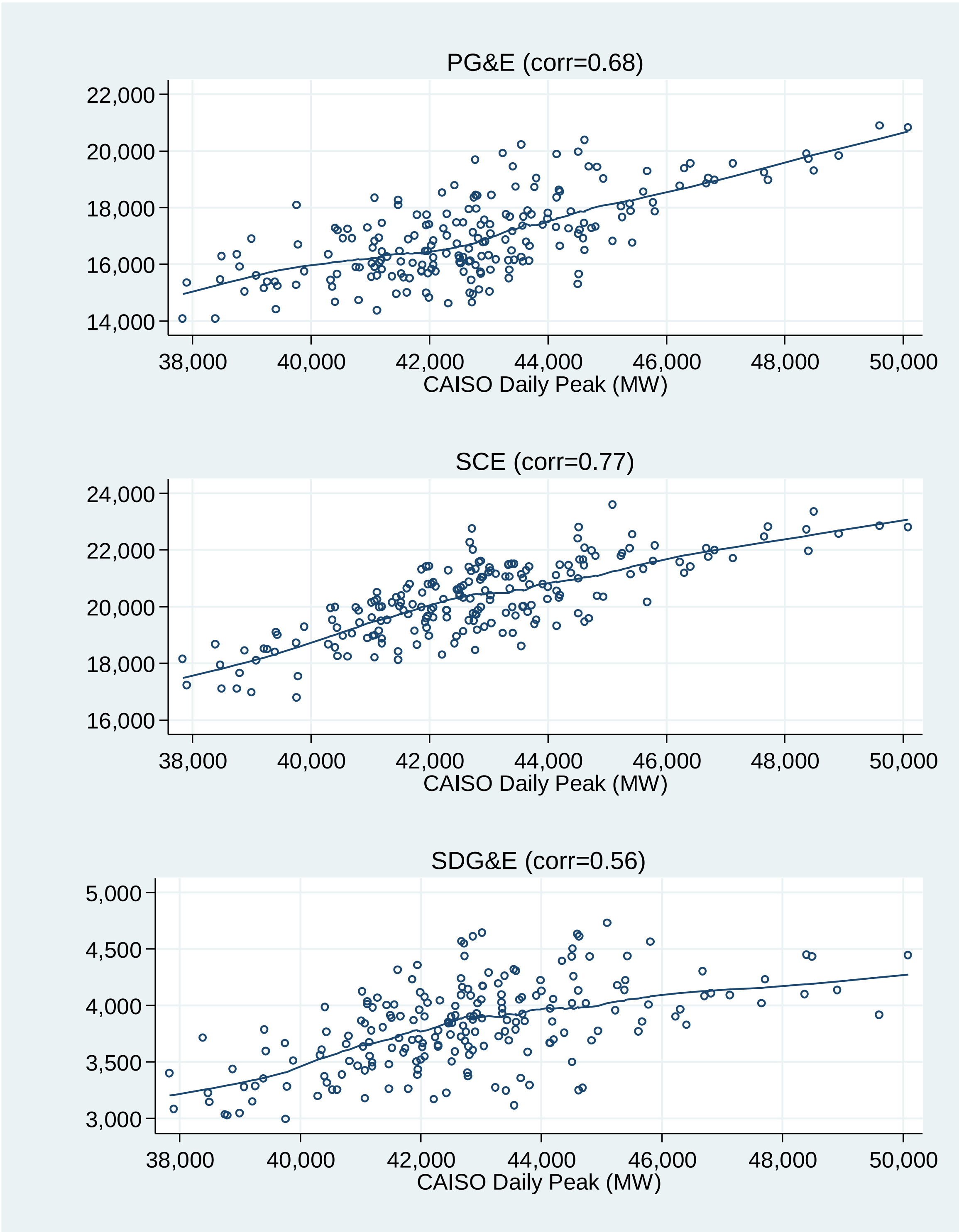
[14] See CPUC Rulemaking (R.) 07-01-041 Decision (D.) 08-04-050, "Adopting Protocols for Estimating Demand Response Load Impacts" and Attachment A, "Protocols."

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

However, whenever CAISO loads have exceeded 45,000 MW, loads typically have been high across all three IOU's.

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



Tables 2-1 through 2-3 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 lower on average than the utility specific weather for PG&E for both 1-in-2 and 1-in-10 year weather conditions. For SCE, CAISO values are hotter than the utility-specific scenarios under normal weather conditions and nearly equal under extreme weather conditions for the typical event day. For SDG&E, the CAISO weather is slightly warmer under 1-in-2 year weather and slightly cooler under 1-in-10 year conditions.

Table 2-1: PG&E Enrollment Weighted Ex Ante Weather Values (mean17)

Day Type		PG&E Based Weather		CAISO Based Weather	
		1-in-2	1-in-10	1-in-2	1-in-10
Typical Event Day		76.0	80.2	73.6	76.8
Peak Day	May	70.0	79.7	68.3	73.0
	June	76.1	81.6	76.1	76.1
	July	76.1	81.1	74.4	79.4
	August	76.3	79.9	72.4	77.4
	September	75.6	78.3	71.7	74.2
	October	68.9	75.2	68.8	71.8
Average Weekday	May	63.0	67.4	64.2	63.0
	June	66.6	69.4	65.4	67.6
	July	69.7	72.0	71.6	70.2
	August	69.9	71.3	69.6	68.8
	September	67.4	70.4	67.9	70.2
	October	61.9	64.7	61.9	63.8

Table 2-2: SCE Enrollment Weighted Ex Ante Weather Values (mean17)

Day Type		SCE Based Weather		CAISO Based Weather	
		1-in-2	1-in-10	1-in-2	1-in-10
Typical Event Day		75.7	80.1	77.1	80.0
Peak Day	May	69.6	77.9	68.2	76.5
	June	72.1	76.5	72.8	77.0
	July	75.7	79.8	78.9	79.3
	August	79.4	81.6	78.6	80.9
	September	75.7	82.3	78.0	82.7
	October	74.2	76.8	70.6	77.1
Average Weekday	May	63.6	68.7	63.6	63.4
	June	65.2	70.5	66.7	70.5
	July	73.1	73.8	72.4	73.8
	August	74.2	76.4	72.6	76.4
	September	69.4	72.9	71.1	72.9
	October	63.5	65.9	64.5	67.9

Table 2-3: SDG&E Enrollment Weighted Ex Ante Weather Values (mean17)

Day Type		SDG&E Based Weather		CAISO Based Weather	
		1-in-2	1-in-10	1-in-2	1-in-10
Typical Event Day		72.5	77.3	73.1	75.8
Peak Day	May	67.6	75.8	64.4	72.7
	June	68.1	73.1	68.7	72.9
	July	71.8	77.8	71.5	73.5
	August	74.9	78.5	75.9	76.4
	September	75.0	80.0	76.2	80.5
	October	70.8	75.9	68.3	74.7
Average Weekday	May	62.3	66.2	63.0	62.3
	June	65.2	69.3	64.1	67.2
	July	68.7	70.4	69.3	69.2
	August	70.0	72.8	70.0	73.7
	September	68.1	71.4	69.6	71.4
	October	65.2	67.7	65.4	67.7

2.4 Key Changes for the 2014 Evaluation

The PY2014 evaluation follows an approach similar to previous evaluations at a high level. However, certain aspects have been updated to reflect new information available from additional applications and feasibility studies and further discussion with the utilities. Table 2-4 contains a summary of the key changes and rationale. Additional details and in-depth discussion are contained in Appendix A.

Table 2-4: Summary of Key Changes for the PY2014 Evaluation

Key Changes	Comments
1. Budget scenarios for unidentified projects (Step 1, Figure 2-1) are determined based on remaining funds rather than the total budget.	• Once applications are received, uncertainty associated with costs for these projects is reduced. Basing the unidentified budget scenarios off the remaining funds appropriately allocates more certainty with the identified projects and less certainty with the unidentified projects.
2. Aggregate peak load shift for each IOU was allocated to each LCA in proportion to the distribution of C&I customers with annual maximum demand greater than 500 kW for PG&E and 1 MW for SCE located in each LCA.	• Previous evaluations based the weighting on the distribution of medium and large C&I customers. • The PY2014 evaluation refined this assumption based on newly available applications and updated information. • SDG&E has only a single LCA, thus not requiring weighting.
3. Revised ex ante conversion factors based on new building simulation models and updated weather were developed for unidentified projects across all three utilities.	• The CPUC is requiring that ex ante forecasts be developed based on weather conditions tied to the CAISO system peak as well as tied to individual utility peak. The addition of CAISO peak reporting requirements led to the determination to update the conversion factors in order to meet the new requirement. New, utility specific weather conditions were also developed.
4. A single customizable 2008 vintage Title 24 compliant building simulation model was used to develop the conversion factors for estimating impacts across months and weather conditions.	• A single customizable model for use across all utilities that can be adapted based on location provides an appropriate level of rigor while staying within the evaluation budget.
5. Building simulation modeling used to develop the conversion factors (item 4 above) was completed at the LCA level.	• The single Title 24 model referenced above was calibrated such that the cooling load in the building simulation was appropriately sized for the climatic conditions in each of the 12 LCAs across the three IOUs. • The result was 1 distinct building simulation model for each LCA (12 in total).
6. Space cooling building simulation models (item 4 above) were used to develop the conversion factors for both space cooling and process cooling installations.	• Process cooling installations are not generalizable because they are highly customized by industry and location, and the cooling load exhibits significant seasonality due to both fluctuations in temperature and changes in the level of production. • The range of sensitivity in terms of the percentage difference in cooling load between 1-in-2 and 1-in-10 monthly peak days exhibit similar upper and lower limits to commercial AC cycling programs (space cooling).

Key Changes	Comments
7. The TES system for unidentified projects was sized to offset the full chiller load under peak conditions.	• Among those projects with sufficient data available, 7 of the 9 are designed to shift between 95% and 100% of the maximum peak cooling load.
8. Updated ex ante weather conditions included the CAISO system peak in addition to the utility system peak.	• The new ex ante weather data incorporated the most recent weather data available and was used for inputs in all of the building simulation models.
9. For LCAs with multiple weather stations, Nexant developed a weighted ex ante weather file based on the proportion of customers similar in size to existing PLS applicants assigned to each weather station within an LCA.	• Aggregating and weighting the weather before running the model rather than running the building simulation models for each weather station minimized the number of costly building simulation runs while providing the level of detail necessary to develop the load impact tables.
10. The "utility specific" hottest 1-in-10 peak weather day for each LCA based on the new ex ante weather data was used as a proxy for the weather conditions used to calculate the incentive payment based on the maximum peak load to be shifted.	• ASHRAE 2% conditions were used in previous evaluations. • Updated information made available through new feasibility studies in addition to the new building simulation modeling approach resulted in the 1-in-10 peak day being the optimal condition as a proxy for the incentive payment calculation conditions.
11. Ex ante conversion factor ratios were restricted to a maximum value of 1.	• Load reductions in the ex ante tables must not exceed the maximum load impact specified under the incentive payment calculation conditions.

3 Summary of Assumptions and Enrollment Forecast

Table 3-1 provides a summary of the ex ante forecast assumptions by utility. The table is included to provide transparency to the types of assumptions that must be made in the PY2014 evaluation. One significant assumption that has changed in the PY2014 evaluation is the assumed time period for budget commitment, which will end in 2016 for all three IOUs now that the bridge funding for the PLS program has been approved by the CPUC. Consequently, the timing of when projects come online will also change for PG&E and SCE, given that they previously forecasted funding to expire in 2014. With the availability of incentives extended through 2016, it may be reasonable to assume that projects come online as late as 2018 given that it is expected to take around two years for some projects to become operational. As in the PY2013 evaluation, the uncertainty associated with the percent of the total budget to be committed is reflected in the base case, low and high scenarios. The assumed percent of total budget to be committed in each scenario and the other remaining assumptions were discussed with each utility, and are documented in Table 3-1.

In the base scenario, PG&E assumed 30% of the total PLS incentive budget as the level of incentive budget committed to projects by the end of 2016;[16] SCE projects a 65% budget commitment by the end of 2016; and SDG&E expects 75% allocation of its PLS incentive budget by the end of 2016. The uncertainty associated with the percent of the total budget to be committed is reflected in the low and high scenarios. Using the applications that have been received thus far as a guide, three PLS-TES installation sizes were assumed for PG&E's unidentified projects—small (100 kW of load shift), medium (400 kW) and large (1,714 kW). In the base case, PG&E projects one large, two medium and five small projects, in addition to the current identified projects. In the low case, PG&E projects three additional medium projects and three additional small projects. In the high case, an additional two large, three medium and four small projects are included in addition to the current identified projects. SCE and SDG&E assumed a uniform installation size of 675 kW and 750 kW, respectively, which was informed by their somewhat homogenous mix of applications thus far. In the base case, these assumptions yield seven additional projects for SCE and two additional projects for SDG&E. Regardless of the assumed installation sizes, the total ex ante load impact estimates are primarily a function of the percent of the total budget to be committed by scenario. Therefore, while the uniform project size assumption may not be accurate for SCE and SDG&E, it does not affect the main results of interest—the ex ante load impact estimates.

[16] The cost-effectiveness analysis filed along with the Statewide PLS program proposal (D.12-04-045 and Resolution E-4586) assumed that the total incentive budget would be spent by end of 2014. The assumptions made in this evaluation differ significantly from that scenario, and are based on the best available information at this time.

Table 3-1: Summary of Ex Ante Forecast Assumptions by Utility[17]

Assumption		PG&E	SCE	SDG&E
Total ‘12-‘14 PLS Incentive Budget		$13,500,000	$12,690,000	$3,000,000
$ Committed to Existing Applications from ‘12-‘14 Budget		[redacted]	[redacted]	[redacted]
Total ‘15-’16 PLS Bridge Funding Incentive Budget		$9,000,000	$6,533,333	$2,000,000
$ Committed to Existing Applications from ‘15-‘16 Bridge Funding		[redacted]	[redacted]	[redacted]
Total $ for Existing Applications		[redacted]	[redacted]	[redacted]
Budget Remaining for Unidentified Projects		[redacted]	[redacted]	[redacted]
% of Total Budget to be Committed by Scenario	Low	15%	40%	60%
	Base	30%	65%	75%
	High	50%	90%	90%
Time Period of Budget Commitment		2015-2016	2015-2016	2015-2016
% of Projects Dropped After Budget Commitment		10%		
Annual % Degradation (After Year 5)		2.5%		
Installation Size (kW)		Small – 100 kW, Medium – 400 kW, Large – 1,714 kW	675 kW	750 kW
Timing of When Projects Come Online	Identified	Based on most recent information regarding proposed project		
	Unidentified	Small – 2016-17, Medium – 2016-17, Large – 2016-17	2017-2018	2017-2018
Location of Installations		Distributed by LCA, proportional to C&I population		

As discussed in Section 2.1, five years after each forecasted PLS-TES installation, the ex ante impacts are assumed to degrade at a rate of 2.5% per year. This assumption was made in consultation with program managers and is consistent with last year’s evaluation. In addition, without any information on where these projects will be located, the aggregate peak load shift was allocated to each LCA in proportion to the distribution of nonresidential customers located in each LCA. Considering that the utilities have received applications from customers that are located in LCAs that are not usually associated with having high cooling load, the expectation regarding where these PLS-TES installations will come online is unclear. Ultimately, with process cooling being eligible for PLS program incentives, the program is viable in many different climates as the current applications have indicated.

Based on these assumptions, Figure 3-1 provides the enrollment forecast by utility and type of project for the base scenario. As discussed in Section 2, customers are not defined as enrolled until their PLS-TES installation has come online. Given the timeline required for the PLS application and verification process, the enrollment forecast does not show any projects coming

[17] In instances where the customer information does not satisfy the 15/15 aggregation rule for non-residential customers or the 100 aggregation rule for residential customers under D.14-05-016,that information has been redacted from the public version, and are making a confidential version available to the Commission’s Energy Division.

online until 2015. In 2015, the enrollment comes from one of PG&E's small identified projects. Most of the PG&E and SCE identified projects are expected to come online by the end of 2016. Enrollment reaches a steady state in 2018, with around 27 projects in the Statewide PLS program. Again, this evaluation only includes projects that the IOUs commit to through 2016, so if the PLS incentive budget expands or if funding is extended past the current deadlines, the program will have higher enrollment potential.

Figure 3-1: Enrollment Forecast by Utility and Type of Project – Base Scenario

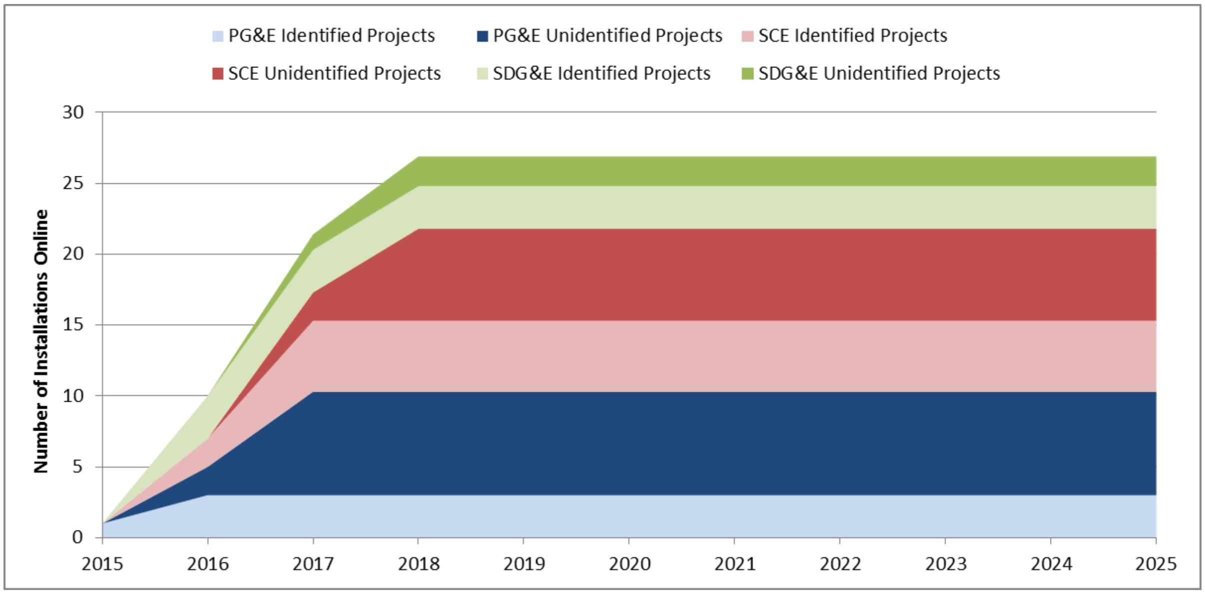


Table 3-2 provides the PLS program enrollment forecast by utility and LCA for each year until a steady state is reached for the current budget timeline. As discussed, given the timeline required for the PLS application and verification process, and the lengthy equipment installation process, the enrollment forecast only shows a single project coming on line in 2015. Of all the LCAs in California, the greatest number of PLS program installations is expected to occur in the LA Basin LCA (10 of 27 installations). The Greater Bay Area and SDG&E are the only other LCAs in California that are forecasted to have more than five PLS program installations. Within several of the LCAs, the expected number of PLS program installations that forecasted to come online is less than one. While fractions of installations are not possible in reality, these projected enrollment numbers properly reflect the uncertainty of the forecast. In this case, the realistic expectation is that every LCA has a chance of ultimately having a PLS program installation. However, because several of the LCAs are so small in terms of the number of IOU customers that are located there, the expected number of installations is less than one in those LCAs.

Table 3-2: PLS Program Enrollment Forecast by Utility and LCA – Base Scenario

Utility	LCA	2015	2016	2017	2018–2025
PG&E	Greater Bay Area	0	2.1	5.1	5.1
	Greater Fresno	0	0.2	0.6	0.6
	Humboldt	0	0	0.1	0.1
	Kern	0	0.1	0.5	0.5
	Northern Coast	1	1.1	1.4	1.4
	Other	0	1.3	2	2
	Sierra	0	0.1	0.2	0.2
	Stockton	0	0.1	0.4	0.4
	Total (PG&E)	*1*	*5*	*10.3*	*10.3*
SCE	LA Basin	0	2	6.5	10
	Outside LA Basin	0	0	0.1	0.5
	Ventura	0	0	0.3	1
	Total (SCE)	*0*	*2*	*6.9*	*11.5*
SDG&E		0	3	4.1	5.1
Total (Statewide)		**1**	**10**	**21.3**	**26.9**

4 Ex Ante Impact Estimates

This section provides the ex ante impact estimates for peak period (1 to 6 PM) conditions for the program operational months of May through October. In accordance with the Resource Adequacy window, the peak period is defined as 1 to 6 PM, even though PLS program participants are required to shift load from 12 to 6 PM (for SCE and PG&E) or 11 AM to 6 PM (for SDG&E). Estimates for average weekdays can be found in the Excel load impact tables.[18] The results are provided separately for each utility. A comparison to last year's ex ante forecast is also provided for each utility. The forecast runs from May 2015 through October 2025.

Load impacts during the months of November through March are expected to be zero or nearly zero due to a lack of significant cooling load in most areas during those months. In addition, because customers will not be required to run their systems during those months, it is best to assume that the impacts are zero until further information becomes available. Therefore, estimates have not been developed for those months. In the future, if installations occur in areas where there is significant winter cooling load and if customers appear to be shifting during those times, it may make sense to estimate impacts for those months.

Similarly, customers technically do not have to run their systems during April and SCE customers do not have to run their systems during May or October (see Table 1-1). Regardless, customers may choose to simply run their systems when the cooling season begins. It is uncertain whether that pattern will develop, and it depends on how easy and financially advantageous it is for customers to run their systems when they are not required to do so. For that reason, April impacts are also excluded from the analysis until empirical data is available to support load impacts outside of the specified program guidelines. May and October impacts for SCE have been included in the evaluation to provide consistency in results across the utilities. However, those months include more uncertainty than the others due to being outside of the regular SCE program season.

It is also important to note that these impacts represent load that is shifted, not eliminated. The evaluation assumes that all avoided peak period load, plus an additional 5%, is consumed during the hours from 9 PM to 6 AM. PLS systems are required to use no more than 5% additional energy than the baseline system. Because not all cooling load comes during the peak period and we have only added 5% to the shifted peak period load, our assumption implies that the 5% limit will be binding for many, but not all sites.

Finally, each installation is expected to last a minimum of five years, after which we have assumed a degradation in load impacts of about 2.5% per year, which corresponds to an expected life of about 20 years for each installation.[19] We have assumed the same degradation factor for each month within a given year so that the percentage difference measured May over May would be identical to the difference measured June over June and so forth. The degradation factor is a major simplification of what will likely become a complex issue if the

[18] Due to customer confidentiality concerns, these load impact tables are not available publicly.

[19] The actual assumed trajectory is for a constant amount of absolute shifting capacity loss each year after the fifth year, such that the expected total life is 20 years and the maximum total life is 35 years. If the program becomes a major part of the energy savings portfolio, then more nuanced assumptions for shift capacity degradation will be in order.

program continues over the next decade. Similar to the issue of projecting PLS enrollment, this is primarily an empirical question that is unlikely to be determined accurately in advance. PLS-TES systems are too complex and their continued function is based on too many variables for a theoretical analysis to have any serious hope of accuracy. Therefore, we have chosen a simple set of values for degradation that dovetail with the assumptions that utility staff consider reasonable; and we recognize the significant uncertainty associated with these projections.

4.1 PG&E Results

Table 4-1 provides the ex ante load impact estimates for monthly system peak days in May through October of 2016,[20] under the utility specific 1-in-2 and 1-in-10 year weather conditions for the base scenario. PG&E's two remaining identified projects are forecasted to become operational in 2016, in addition to two small unidentified projects, resulting in a total of five projects yielding 2.2 MW on a utility specific August 1-in-10 peak day. Table 4-2 provides results for PG&E in 2017 when enrollment reaches the steady state under the currently approved funding cycle. The base case scenario load impact for the utility specific August 1-in-10 peak day reaches 4.1 MW. It is important to note that the Greater Bay Area includes many hot areas with large commercial and industrial facilities, including Silicon Valley, Concord and San Ramon.

The CAISO specific August 1-in-10 peak day load impact in 2017 is expected to be 4.2 MW, which is approximately 2% larger than the utility specific comparable load impact. Typically the utility specific load impacts are larger than the CAISO load impacts as identified by the conversion factors presented in Appendix A. However, a large identified project appears to only partially offset the total cooling load above a particular temperature threshold, resulting in higher load impacts under the generally cooler CAISO peak conditions in the local climate. Due to the unique characteristics and expected size of this specific installation relative to the entire program, the CAISO specific impacts are often slightly larger than the utility specific impacts. The CAISO specific peak load impacts will be covered in further detail below.

[20] Tables for 2015 are not included due to the results pertaining to only a single customer.

Table 4-1: PG&E Ex Ante Load Impact Estimates (1-6 PM) on Monthly Peak Days for May-October 2016 (kW) Utility Specific Peak – Base Scenario

LCA	May		June		July		August		September		October	
	1-in-2	1-in-10	1-in-2	1-in-10	1-in-2	1-in-10	1-in-2	1-in-10	1-in-2	1-in-10	1-in-2	1-in-10
Greater Bay Area	Redacted to protect confidential customer information											
Greater Fresno	49	50	55	55	57	58	55	60	53	53	48	47
Humboldt	6	7	6	7	7	8	7	7	7	7	6	7
Kern	45	36	48	47	48	50	48	50	46	47	41	42
Northern Coast	80	90	87	97	91	95	88	95	52	57	39	41
Other	Redacted to protect confidential customer information											
Sierra	37	39	40	40	41	44	40	42	38	39	34	35
Stockton	18	19	19	20	20	21	20	21	19	19	16	17
Total	**1,801**	**2,063**	**2,092**	**2,098**	**1,880**	**1,850**	**2,075**	**2,169**	**1,697**	**1,938**	**1,579**	**1,709**

Table 4-2: PG&E Ex Ante Load Impact Estimates (1-6 PM) on Monthly Peak Days for May-October 2017 (kW) Utility Specific Peak – Base Scenario

LCA	May		June		July		August		September		October	
	1-in-2	1-in-10	1-in-2	1-in-10	1-in-2	1-in-10	1-in-2	1-in-10	1-in-2	1-in-10	1-in-2	1-in-10
Greater Bay Area	2,280	2,613	2,561	2,649	2,365	2,376	2,559	2,678	2,238	2,498	2,115	2,250
Greater Fresno	178	182	198	198	206	211	199	214	189	191	172	168
Humboldt	22	24	23	26	26	28	26	27	25	26	22	24
Kern	163	130	173	169	172	180	173	178	165	168	148	151
Northern Coast	180	201	195	217	205	212	197	212	160	172	138	146
Other	437	489	509	505	542	570	526	558	503	515	407	445
Sierra	132	141	145	146	146	157	145	151	138	141	121	127
Stockton	65	68	70	71	73	76	73	74	67	69	57	60
Total	**3,457**	**3,848**	**3,874**	**3,980**	**3,735**	**3,809**	**3,899**	**4,092**	**3,485**	**3,780**	**3,179**	**3,371**

Figure 4-1 illustrates how the August 1-in-10 load impact estimates vary by forecast year and scenario. Figure 4-2 shows the same results for August 1-in-2 weather conditions. Across the forecast years and scenarios, the impacts are slightly higher under August 1-in-10 weather conditions but the difference is less than 0.2 MW. As described in Section 3, the three scenarios correspond to different forecasts of the percent of the total PLS program incentive budget that will be committed by the end of 2016, with 15% assumed under the low scenario, 30% under the base scenario and 50% under the high scenario. The different percentages of the total PLS program incentive budget being committed translate into different enrollment forecasts across the three scenarios. We consider these scenarios to be about the best that can be done to estimate the uncertainty associated with these estimates, since the estimation method was not statistical in nature and therefore there are no standard errors to report. As a result of this uncertainty, the aggregate load reduction of the program varies substantially. When the aggregate impact peaks in 2017 (before the 2.5% annual degradation begins), the PLS program is expected to deliver from 2.7 MW in the low scenario to nearly 6 MW in the high scenario. At 4 MW, the aggregate impact for the base scenario is in the middle.

Figure 4-1: PG&E August 1-in-10 Monthly System Peak Day Load Impacts (1 to 6 PM) by Forecast Year and Scenario

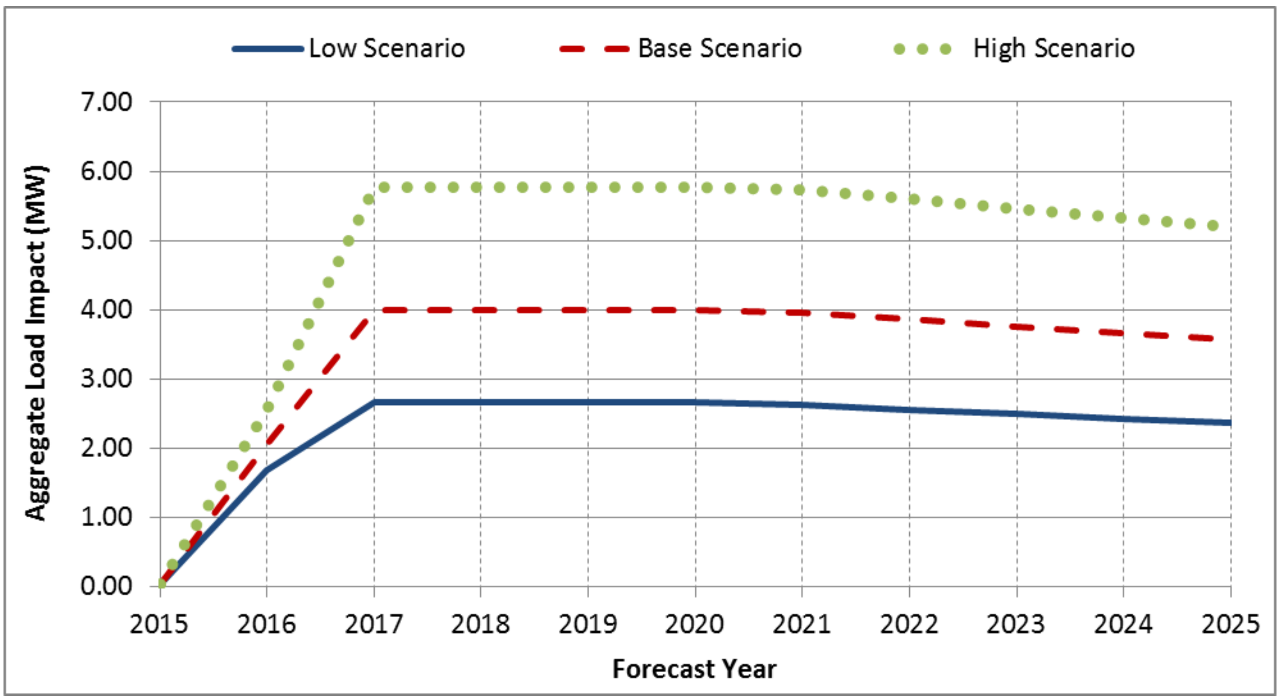


Figure 4-2: PG&E August 1-in-2 Monthly System Peak Day Load Impacts (1 to 6 PM) by Forecast Year and Scenario

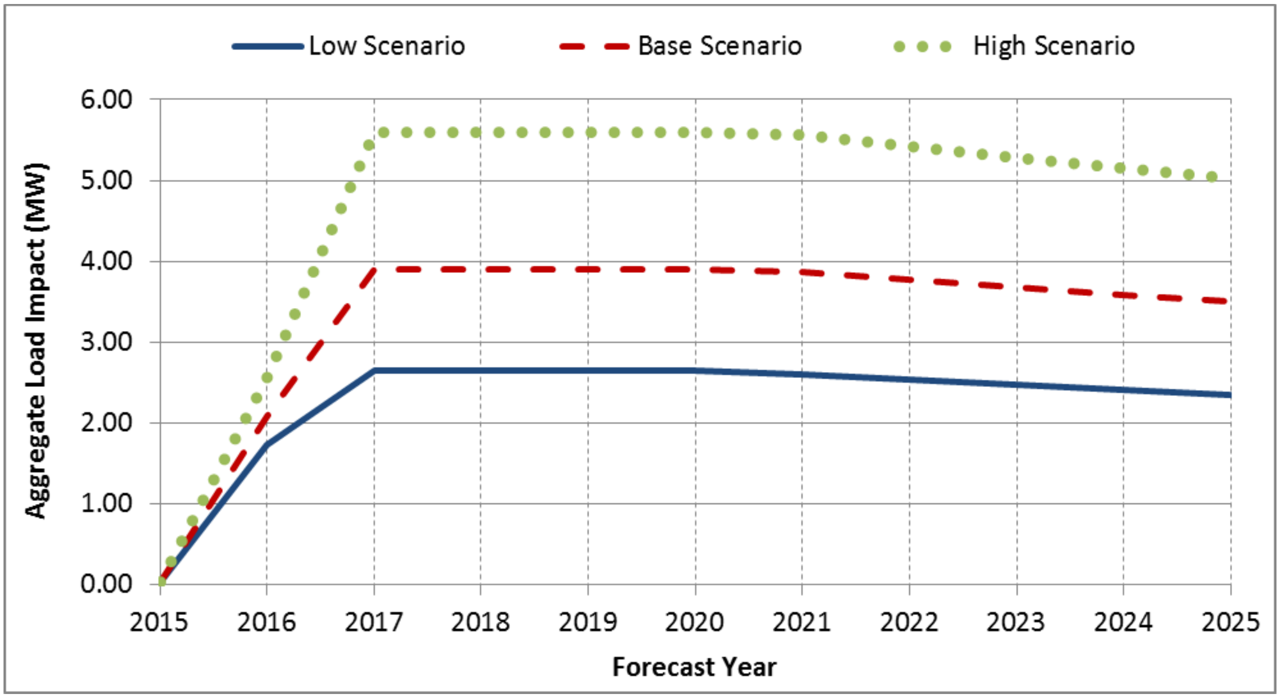


Table 4-3 shows the expected trajectory of load impacts under August 1-in-10 weather conditions from 2015 through 2025 by LCA for both the utility specific and CAISO specific weather conditions. Table 4-4 shows the same results for August 1-in-2 conditions. The Greater Bay Area and Other LCAs combined account for a majority of load impacts throughout the forecast horizon under both 1-in-10 and 1-in-2 year weather conditions for both CAISO and utility specific peaks. None of the other six LCAs comprise more than 10% of load impacts. As a result of the assumed 2.5% annual degradation in load impacts after year five, the aggregate load reduction decreases from around 4.1 MW in 2017 under 1-in-10 year, utility-specific weather conditions to 3.6 MW in 2025. Similarly, the CAISO-specific impacts decrease from 4.2 MW in 2017 to 3.7 MW in 2025.

As noted above, the CAISO-specific impacts tend to be slightly larger than the utility-specific impacts. This is due to the unique characteristics of a single large customer. This trend appears through the entire time horizon of the forecast. To develop a better sense of the relationship between the utility-specific and CAISO impacts, the average impact by year can be calculated excluding the LCA containing the large customer. Upon removing that LCA from the calculation, we find the August 1-in-10 impact is approximately 5% larger for the utility-specific peak compared to the CAISO-specific peak. This difference of approximately 5% is what should be expected for future unidentified projects.

Table 4-3: PG&E August 1-in-10 Monthly System Peak Day Load Impacts (1–6 PM) by LCA and Forecast Year – Base Scenario

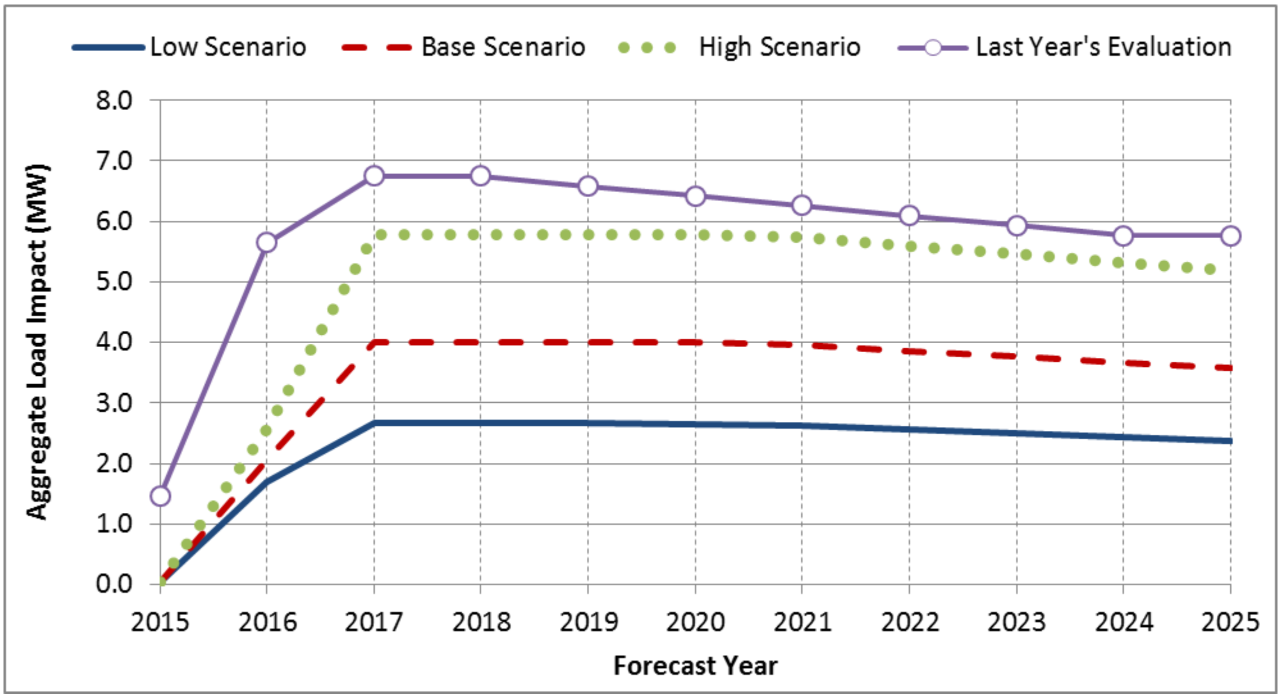
Peak Type	LCA	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Utility Specific	Greater Bay Area	Redacted to protect confidential customer information		2,678	2,678	2,678	2,678	2,648	2,580	2,514	2,450	2,388
	Greater Fresno		60	214	214	214	214	214	209	204	199	194
	Humboldt		7	27	27	27	27	27	26	25	25	24
	Kern		50	178	178	178	178	178	174	170	165	161
	Northern Coast		95	212	212	212	212	210	205	200	195	190
	Other			558	558	558	553	548	535	522	509	496
	Sierra		42	151	151	151	151	151	147	143	140	136
	Stockton		21	74	74	74	74	74	73	71	69	67
	Total		**2,169**	**4,092**	**4,092**	**4,092**	**4,087**	**4,051**	**3,948**	**3,849**	**3,751**	**3,657**
CAISO Specific	Greater Bay Area			2,871	2,871	2,871	2,871	2,833	2,761	2,690	2,621	2,553
	Greater Fresno		58	208	208	208	208	208	203	198	193	188
	Humboldt		7	26	26	26	26	26	25	24	24	23
	Kern		49	178	178	178	178	178	173	169	165	161
	Northern Coast		54	166	166	166	166	165	161	157	153	149
	Other			549	549	549	545	540	527	514	501	489
	Sierra		41	148	148	148	148	148	144	141	137	134
	Stockton		20	73	73	73	73	73	71	69	67	66
	Total		**2,371**	**4,219**	**4,219**	**4,219**	**4,214**	**4,171**	**4,065**	**3,961**	**3,860**	**3,762**

Table 4-4: PG&E August 1-in-2 Monthly System Peak Day Load Impacts (1–6 PM) by LCA and Forecast Year – Base Scenario

Peak Type	LCA	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Utility Specific	Greater Bay Area	Redacted to protect confidential customer information		2,559	2,559	2,559	2,559	2,527	2,459	2,394	2,330	2,268
	Greater Fresno		55	199	199	199	199	199	194	189	184	179
	Humboldt		7	26	26	26	26	26	26	25	24	24
	Kern		48	173	173	173	173	173	168	164	160	156
	Northern Coast		88	197	197	197	197	196	191	186	182	177
	Other			526	526	526	522	517	505	492	480	468
	Sierra		40	145	145	145	145	145	142	138	135	131
	Stockton		20	73	73	73	73	73	72	70	68	66
	Total		**2,075**	**3,899**	**3,899**	**3,899**	**3,894**	**3,856**	**3,756**	**3,658**	**3,563**	**3,470**
CAISO Specific	Greater Bay Area			2,142	2,142	2,142	2,142	2,121	2,065	2,011	1,958	1,907
	Greater Fresno		51	184	184	184	184	184	180	175	171	167
	Humboldt		6	23	23	23	23	23	23	22	22	21
	Kern		44	157	157	157	157	157	153	150	146	142
	Northern Coast		51	155	155	155	155	154	150	146	142	139
	Other			475	475	475	472	468	456	445	434	423
	Sierra		37	133	133	133	133	133	129	126	123	120
	Stockton		18	65	65	65	65	65	63	62	60	58
	Total		**1,593**	**3,335**	**3,335**	**3,335**	**3,331**	**3,305**	**3,220**	**3,137**	**3,056**	**2,977**

Figure 4-3 compares the ex ante load impact estimates from this evaluation to those from last year's PLS program evaluation, for the August 1-in-10 monthly system peak day. In general, the load impact estimates are significantly lower than those of last year's evaluation. The main reasons for these differences are 1) the remaining funds available for new applications are lower at $8.8M due to the new bridge funding cycle, and 2) the percentage of the remaining budget expected to be spent decreased from 50% to 30% in the medium scenario. This change is a conservative estimate, and was based on the most recent information available, including the applications that PG&E has received at the time of this evaluation. These changes coupled with the identified applications shifting out by at least a year result in the base scenario forecast this year being roughly 40% lower than the estimates in last year's evaluation.

Figure 4-3: PG&E Comparison of August 1-in-10 Monthly System Peak Day Load Impacts (1 to 6 PM) to Base Scenario from Last Year's PLS Program Evaluation



4.2 SCE Results

Table 4-5 provides the ex ante load impact estimates for monthly system peak days in May through October of 2016, under SCE-specific, 1-in-2 and 1-in-10 year weather conditions for the base scenario. Table 4-6 and Table 4-7 provide similarly formatted results for 2017 and 2018, respectively. No projects are expected to come online during 2015 in SCE's service territory. As such, the 2015 aggregate impacts are expected to be zero across all LCAs and are not included as a table. SCE expects two identified projects and no unidentified projects to come online in 2016. The remaining three identified projects and two additional unidentified projects are forecast to become operational in 2017. The steady state level of projects under the current budget scenario is expected to be reached in 2018 with a total of 11.5 installations and 8.1 MW under the SCE-specific, August 1-in-10 monthly peak conditions.

All of the currently identified applications are located within the LA Basin LCA. The majority of any future applications and related impacts are expected to also remain in the LA Basin LCA given that more than 75% of SCE's non-residential customers with annual maximum demand greater than 1 MW are located within that LCA. Impacts are also reported at the South Orange County and South of Lugo regions. These regions within the LA Basin LCA are required to be reported separately as they are constrained circuits in the area affected by the closure of the San Onofre Nuclear Generating Station (SONGS). In 2018, under SCE-specific August 1-in-10 year conditions, the expected impacts for the constrained circuits are 858 kW and 3.3 MW for South Orange County and South of Lugo respectively. The South of Lugo impact is significant at more than 40% of SCE's aggregate load impact.

CAISO specific impacts are covered in greater detail below. For comparison purposes, the CAISO impact for August 1-in-10 monthly peak conditions is 8 MW, or approximately 1% lower than the comparable utility specific monthly peak. As noted in the ex ante weather description in Section 2 above, the CAISO and SCE utility specific peaks have the highest correlation among the three IOUs.

Table 4-5: SCE Ex Ante Load Impact Estimates (1–6 PM) on Monthly Peak Days for May-October 2016 (kW) – Base Scenario

LCA	May		June		July		August		September		October	
	1-in-2	1-in-10	1-in-2	1-in-10	1-in-2	1-in-10	1-in-2	1-in-10	1-in-2	1-in-10	1-in-2	1-in-10
LCA - LA Basin	Redacted to protect confidential customer information											
Region - South Orange County												
Region - South of Lugo												
LCA - Outside LA Basin												
LCA - Ventura												
Total												

Table 4-6: SCE Ex Ante Load Impact Estimates (1–6 PM) on Monthly Peak Days for May -October 2017 (kW) – Base Scenario

LCA	May		June		July		August		September		October	
	1-in-2	1-in-10	1-in-2	1-in-10	1-in-2	1-in-10	1-in-2	1-in-10	1-in-2	1-in-10	1-in-2	1-in-10
LCA - LA Basin	4,026	4,246	4,168	4,490	4,581	4,875	4,592	4,854	4,476	4,846	4,032	4,298
Region - South Orange County	*448*	*473*	*464*	*500*	*510*	*543*	*511*	*541*	*498*	*540*	*449*	*479*
Region - South of Lugo	*2,180*	*2,299*	*2,256*	*2,431*	*2,480*	*2,640*	*2,486*	*2,628*	*2,423*	*2,624*	*2,183*	*2,327*
LCA - Outside LA Basin	78	79	81	85	90	98	87	94	80	86	73	76
LCA - Ventura	166	174	178	192	193	210	187	201	176	190	164	178
Total	**4,270**	**4,500**	**4,427**	**4,766**	**4,864**	**5,183**	**4,866**	**5,150**	**4,731**	**5,122**	**4,268**	**4,553**

Table 4-7: SCE Ex Ante Load Impact Estimates (1–6 PM) on Monthly Peak Days for May -October 2018 (kW) – Base Scenario

LCA	May		June		July		August		September		October	
	1-in-2	1-in-10	1-in-2	1-in-10	1-in-2	1-in-10	1-in-2	1-in-10	1-in-2	1-in-10	1-in-2	1-in-10
LCA - LA Basin	5,927	6,252	6,136	6,610	6,744	7,178	6,761	7,147	6,590	7,135	5,936	6,328
Region - South Orange County	*712*	*751*	*737*	*794*	*810*	*862*	*812*	*858*	*791*	*857*	*713*	*760*
Region - South of Lugo	*2,798*	*2,951*	*2,896*	*3,120*	*3,183*	*3,388*	*3,191*	*3,373*	*3,110*	*3,368*	*2,802*	*2,987*
LCA - Outside LA Basin	252	257	263	274	292	316	281	304	258	280	235	247
LCA - Ventura	537	564	575	621	624	679	604	652	568	614	529	578
Total	**6,716**	**7,073**	**6,974**	**7,505**	**7,660**	**8,173**	**7,646**	**8,103**	**7,416**	**8,029**	**6,700**	**7,153**

Figure 4-4 illustrates how the August 1-in-10 year load impact estimates vary by forecast year and scenario. Figure 4-5 shows the same results for August 1-in-2 year weather conditions. Across the forecast years and scenarios, the impacts are approximately 6.5% higher under August 1-in-10 year weather conditions. As described in Section 3, the three scenarios correspond to different forecasts of the percent of the total PLS program incentive budget that will be committed by the end of 2016, with 40% assumed under the low scenario, 65% under the base scenario and 90% under the high scenario. When the aggregate impact peaks in 2018, the PLS program is expected to deliver from 6.1 MW in the low scenario to nearly 9.4 MW in the high scenario, under August 1-in-10 weather conditions. The base case scenario forecasts a 7.9 MW load reduction.

Figure 4-4: SCE August 1-in-10 Monthly System Peak Day Load Impacts (1 to 6 PM) by Forecast Year and Scenario

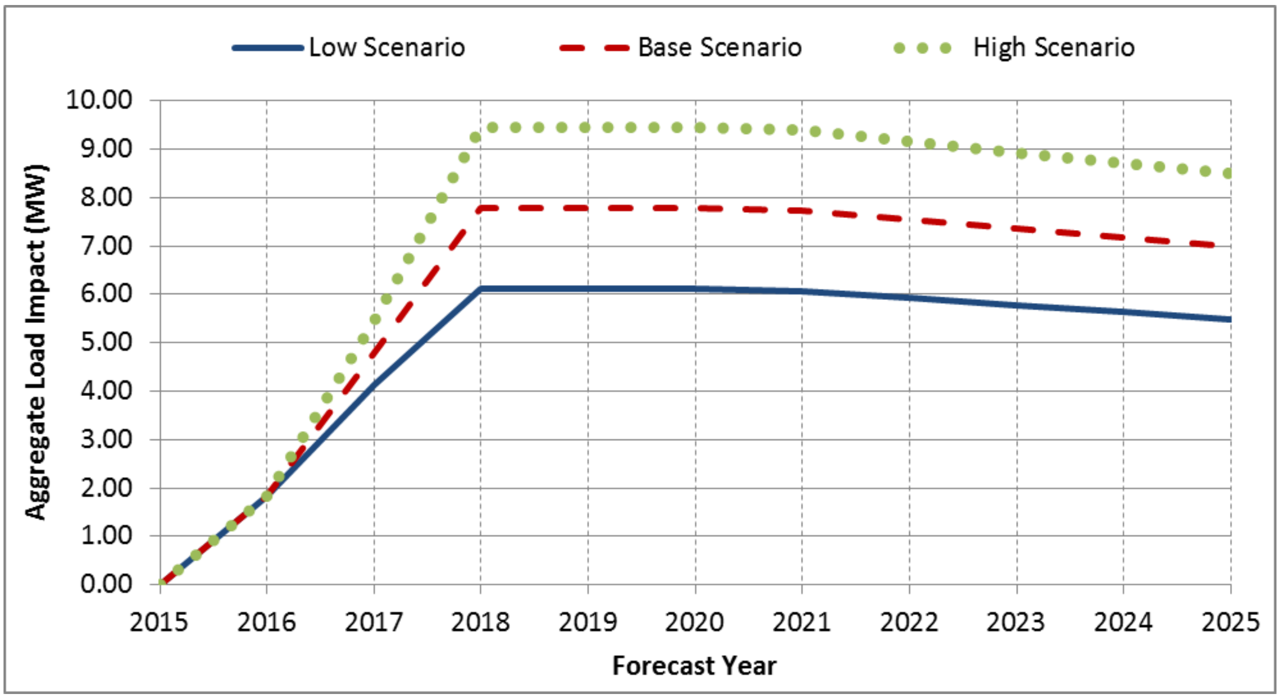


Figure 4-5: SCE August 1-in-2 Monthly System Peak Day Load Impacts (1 to 6 PM) by Forecast Year and Scenario

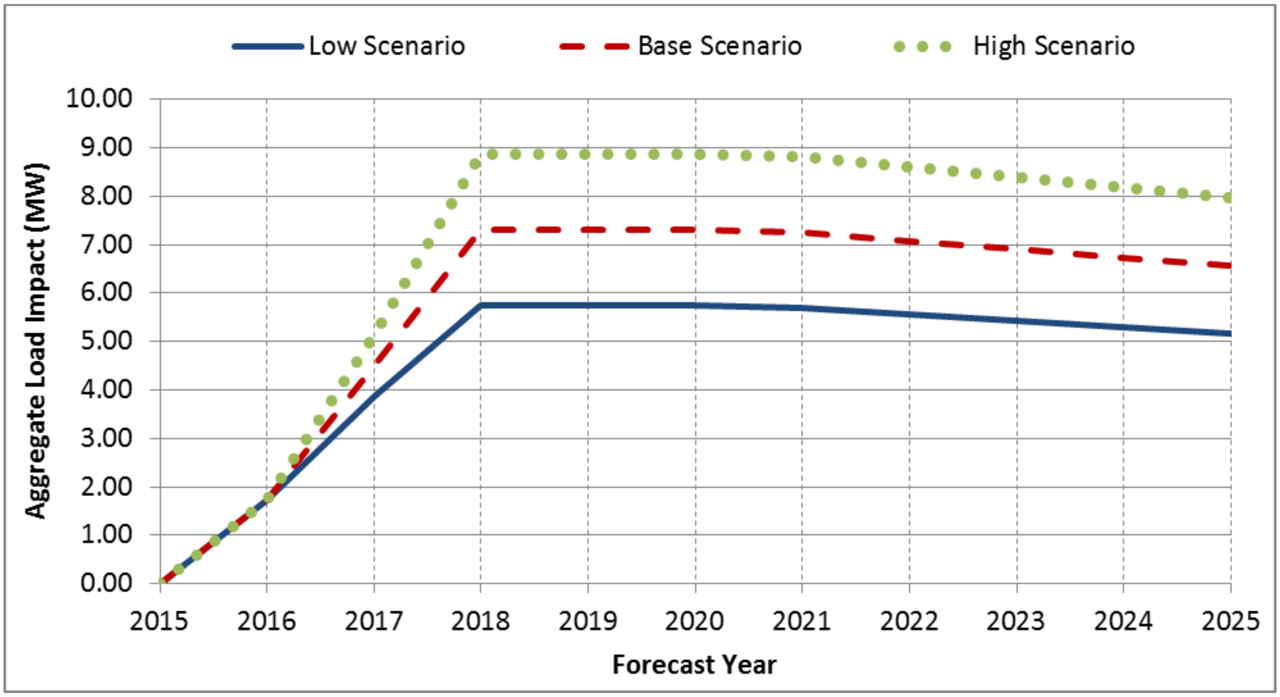


Table 4-8 shows the expected trajectory of load impacts under August 1-in-10 year weather conditions from 2015 through 2025 by LCA for the utility and CAISO specific peaks. Table 4-9 shows the same results for August 1-in-2 conditions. The LA Basin LCA accounts for at least 88% of load impacts over the forecast horizon under both 1-in-10 and 1-in-2 year weather conditions. As a result of the assumed 2.5% annual degradation in load impacts after year five, the aggregate load reduction decreases from around 8.1 MW in 2018 under 1-in-10 year weather conditions to 7.4 MW in 2025. As mentioned above, the CAISO-specific peak is very similar to the SCE utility specific peak and maintains a consistent relationship across all of the years in the forecast. The difference between the utility specific and the CAISO specific peak is approximately 1% under 1-in-10 conditions, and 2% under 1-in-2 conditions, with the utility peak being consistently higher.

Table 4-8: SCE August 1-in-10 Monthly System Peak Day Load Impacts (1-6 PM) by LCA and Forecast Year – Base Scenario

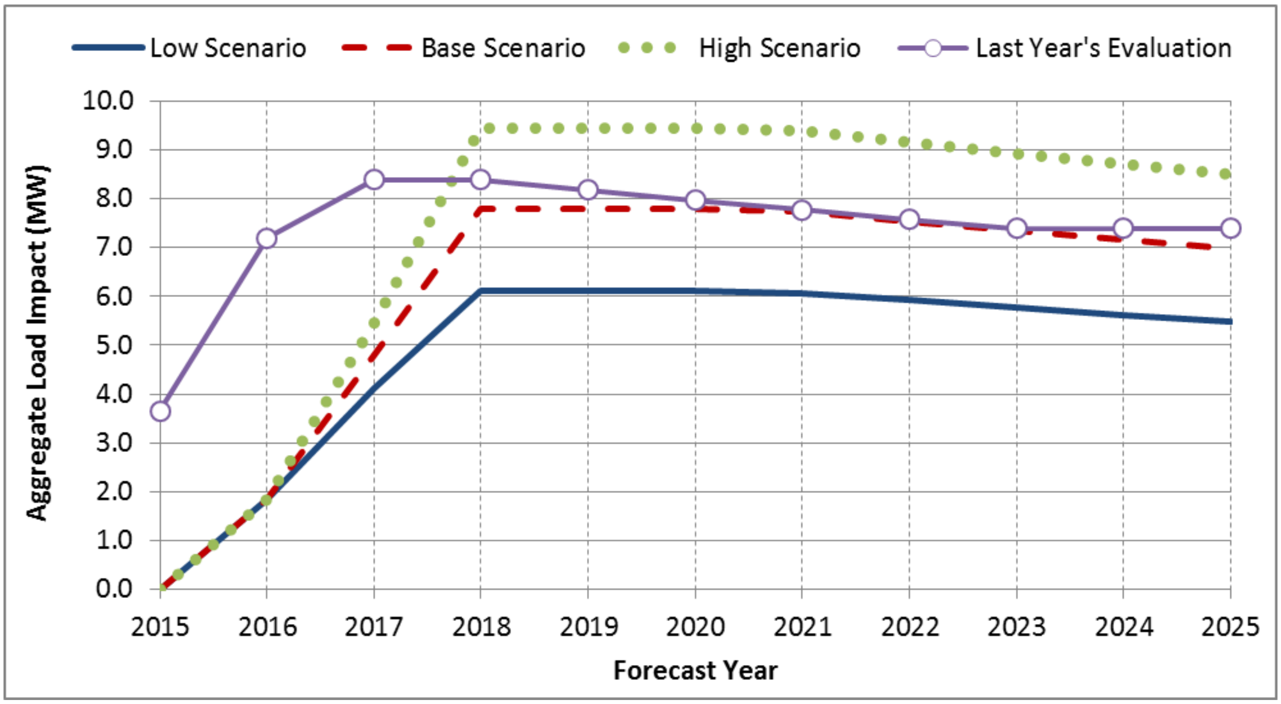
Peak Type	LCA	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Utility Specific	LCA - LA Basin	0	Redacted to protect confidential customer information	4,854	7,147	7,147	7,147	7,096	7,001	6,826	6,654	6,487
	Region - South of Lugo	0		2,628	3,373	3,373	3,373	3,351	3,294	3,211	3,131	3,052
	Region - South Orange County	0		541	858	858	858	858	848	827	806	786
	LCA - Outside LA Basin	0		94	304	304	304	304	304	297	289	282
	LCA – Ventura	0		201	652	652	652	652	652	636	620	604
	Total	**0**		**5,150**	**8,103**	**8,103**	**8,103**	**8,052**	**7,957**	**7,758**	**7,563**	**7,374**
CAISO Specific	LCA - LA Basin	0		4,802	7,069	7,069	7,069	7,019	6,926	6,753	6,584	6,420
	Region - South of Lugo	0		2,600	3,337	3,337	3,337	3,315	3,258	3,177	3,098	3,020
	Region - South Orange County	0		535	849	849	849	849	839	818	798	778
	LCA - Outside LA Basin	0		93	302	302	302	302	302	294	287	280
	LCA – Ventura	0		200	648	648	648	648	648	632	616	601
	Total	**0**		**5,095**	**8,019**	**8,019**	**8,019**	**7,969**	**7,876**	**7,679**	**7,487**	**7,300**

Table 4-9: SCE August 1-in-2 Monthly System Peak Day Load Impacts (1-6 PM) by LCA and Forecast Year – Base Scenario

Peak Type	LCA	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Utility Specific	LCA - LA Basin	0	Redacted to protect confidential customer information	4,592	6,761	6,761	6,761	6,713	6,624	6,459	6,297	6,140
	Region - South of Lugo	0		2,486	3,191	3,191	3,191	3,170	3,116	3,039	2,963	2,889
	Region - South Orange County	0		511	812	812	812	812	802	782	763	744
	LCA - Outside LA Basin	0		87	281	281	281	281	281	274	268	261
	LCA – Ventura	0		187	604	604	604	604	604	589	574	560
	Total	**0**		**4,866**	**7,646**	**7,646**	**7,646**	**7,599**	**7,509**	**7,322**	**7,140**	**6,962**
CAISO Specific	LCA - LA Basin	0		4,484	6,603	6,603	6,603	6,556	6,469	6,307	6,150	5,996
	Region - South of Lugo	0		2,428	3,116	3,116	3,116	3,096	3,043	2,967	2,893	2,821
	Region - South Orange County	0		499	793	793	793	793	784	764	745	726
	LCA - Outside LA Basin	0		87	282	282	282	282	282	275	268	262
	LCA – Ventura	0		187	604	604	604	604	604	589	574	560
	Total	**0**		**4,758**	**7,489**	**7,489**	**7,489**	**7,442**	**7,355**	**7,171**	**6,992**	**6,818**

Figure 4-6 compares the ex ante load impact estimates from this evaluation to those from last year's PLS program evaluation for the SCE-specific, August 1-in-10 monthly system peak day. From 2018 onwards, the load impact estimates for the base scenario are very similar to those of last year's evaluation. The main difference in this year's evaluation is that it forecasts projects coming online at a slower pace. This change is based on information from the PLS program applications that SCE has received since the program opened in October 2013. Considering that this information was not available at the time, last year's evaluation forecasted that seven projects would come online before June 2015 and five additional projects would come online by 2016. The base case assumption of spending 65% of the remaining budget on unidentified projects is the same as last year's assumption.

Figure 4-6: SCE Comparison of August 1-in-10 Monthly System Peak Day Load Impacts (1–6 PM) to Base Scenario from Last Year's PLS Program Evaluation



4.3 SDG&E Results

Table 4-10 provides the ex ante load impact estimates for 2015–2025 monthly system peak days in May through October for SDG&E-specific and CAISO 1-in-2 and 1-in-10 year weather conditions for the base scenario. SDG&E's service territory only has one LCA so the results are not divided geographically. In the base scenario, three SDG&E identified projects come online in 2016 and one additional unidentified project comes online in 2017. One more unidentified project is expected to become operational in 2018 to reach the steady state enrollment under the current budget scenario at five installations producing 3.4 MW of load reduction. Table 4-10 also shows the expected trajectory of load impacts through 2025. As a result of the assumed 2.5% annual degradation in load impacts after year five of each installation, the aggregate load reduction under August 1-in-10 weather conditions decreases from around 3.4 MW in 2018 to 3.1 MW in 2025.

The difference between utility specific and CAISO peaks tend to vary by month. Impacts range from the CAISO-specific, September 1-in-2 monthly peak day in 2018 being 17% greater than the utility specific comparable peak at 3.5 MW and 2.9 MW respectively; to the utility specific July 1-in-10 monthly peak day in 2018 being 24% greater than the CAISO specific comparable peak at 3.6 MW and 2.9 MW respectively. Year over year, the difference between the utility specific peak and the CAISO peak appears to remain fairly constant. For example, the utility specific August 1-in-10 monthly peak load impact is typically around 4% higher than the comparable CAISO specific impact.

Table 4-10: SDG&E Ex Ante Load Impact Estimates (1 to 6 PM) on Monthly Peak Days for April-October 2015-2025 (kW) – Base Scenario

Peak Type	Forecast Year	May		June		July		August		September		October	
		1-in-2	1-in-10	1-in-2	1-in-10	1-in-2	1-in-10	1-in-2	1-in-10	1-in-2	1-in-10	1-in-2	1-in-10
Utility Specific	2015	0	0	0	0	0	0	0	0	0	0	0	0
	2016	Redacted to protect confidential customer information											
	2017	2,200	2,509	2,286	2,473	2,277	2,897	2,501	2,766	2,377	2,952	2,533	2,585
	2018	2,707	3,087	2,812	3,043	2,801	3,564	3,077	3,403	2,924	3,632	3,116	3,180
	2019	2,707	3,087	2,812	3,043	2,801	3,564	3,077	3,403	2,924	3,632	3,116	3,180
	2020	2,707	3,087	2,812	3,043	2,801	3,564	3,077	3,403	2,924	3,632	3,116	3,180
	2021	2,667	3,042	2,771	2,998	2,761	3,512	3,032	3,354	2,882	3,579	3,071	3,134
	2022	2,629	2,998	2,731	2,956	2,722	3,461	2,988	3,305	2,841	3,527	3,027	3,090
	2023	2,563	2,923	2,663	2,882	2,654	3,373	2,913	3,223	2,770	3,438	2,952	3,013
	2024	2,499	2,850	2,596	2,809	2,589	3,288	2,839	3,142	2,701	3,352	2,878	2,937
	2025	2,437	2,778	2,531	2,739	2,525	3,205	2,768	3,063	2,633	3,267	2,807	2,864
CAISO Specific	2015	0	0	0	0	0	0	0	0	0	0	0	0
	2016	Redacted to protect confidential customer information											
	2017	1,927	2,611	2,141	2,519	2,446	2,340	2,558	2,666	2,860	2,916	2,299	2,579
	2018	2,371	3,212	2,635	3,099	3,009	2,879	3,148	3,280	3,518	3,587	2,829	3,173
	2019	2,371	3,212	2,635	3,099	3,009	2,879	3,148	3,280	3,518	3,587	2,829	3,173
	2020	2,371	3,212	2,635	3,099	3,009	2,879	3,148	3,280	3,518	3,587	2,829	3,173
	2021	2,336	3,166	2,597	3,054	2,966	2,837	3,102	3,233	3,467	3,535	2,788	3,127
	2022	2,303	3,121	2,559	3,010	2,924	2,797	3,058	3,186	3,417	3,483	2,749	3,082
	2023	2,245	3,043	2,496	2,935	2,851	2,727	2,981	3,106	3,331	3,394	2,680	3,004
	2024	2,188	2,966	2,433	2,861	2,780	2,659	2,907	3,028	3,247	3,307	2,614	2,928
	2025	2,133	2,892	2,373	2,789	2,712	2,593	2,834	2,952	3,165	3,223	2,549	2,854

Figure 4-7 illustrates how the August 1-in-10 load impact estimates vary by forecast year and scenario. As described in Section 3, the three scenarios correspond to different forecasts of the percent of the total PLS program incentive budget that will be committed by the end of 2016, with 60% assumed under the low scenario, 75% under the base scenario and 90% under the high scenario. When the aggregate impact peaks in 2018 (before the 2.5% annual degradation begins), the PLS program is expected to deliver from 2.9 MW in the low scenario to nearly 3.5 MW in the high scenario, under August 1-in-10 year weather conditions. At 3.2 MW, the aggregate impact for the base scenario is in the middle.

Figure 4-7: SDG&E August 1-in-10 Monthly System Peak Day Load Impacts (1 to 6 PM) by Forecast Year and Scenario

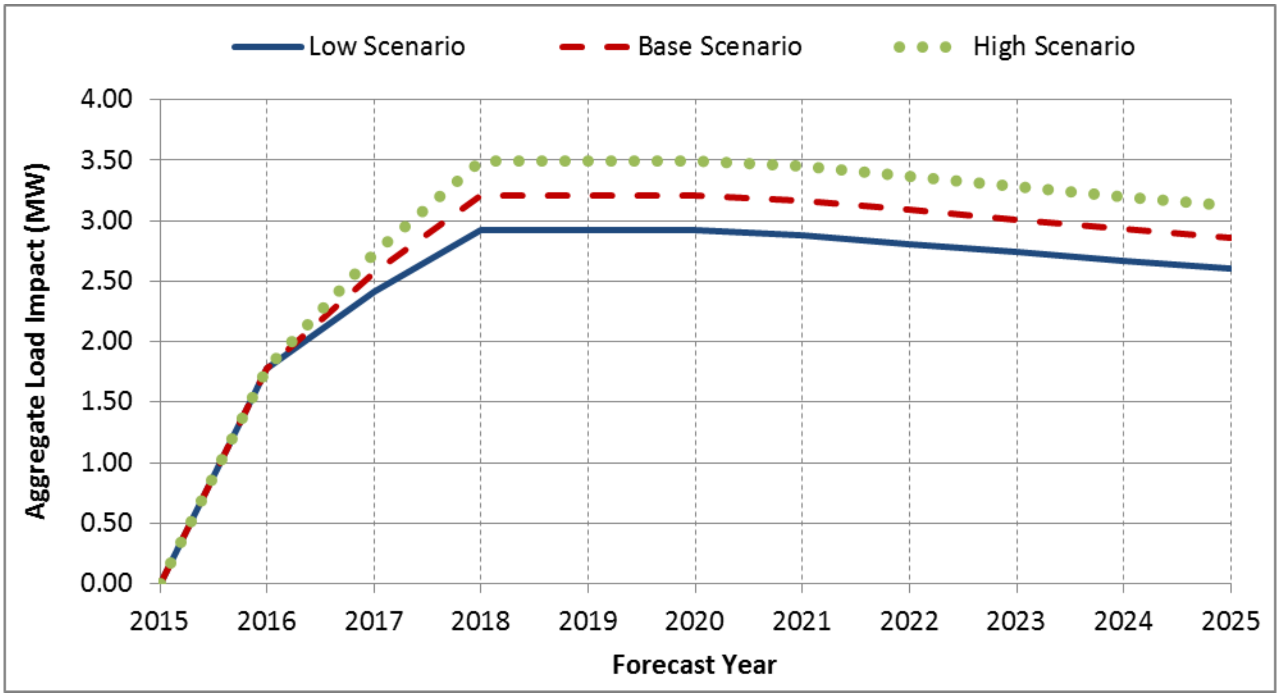


Figure 4-8 shows the same results for August 1-in-2 weather conditions. Across the forecast years and scenarios, the impacts are roughly 11% higher under August 1-in-10 year weather conditions. When the aggregate impact peaks in 2018 (before the 2.5% annual degradation begins), the PLS program is expected to deliver from 2.7 MW in the low scenario to nearly 3.2 MW in the high scenario, under August 1-in-2 year weather conditions. At 2.9 MW, the aggregate impact for the base scenario is in the middle.

Figure 4-8: SDG&E August 1-in-2 Monthly System Peak Day Load Impacts (1 to 6 PM) by Forecast Year and Scenario

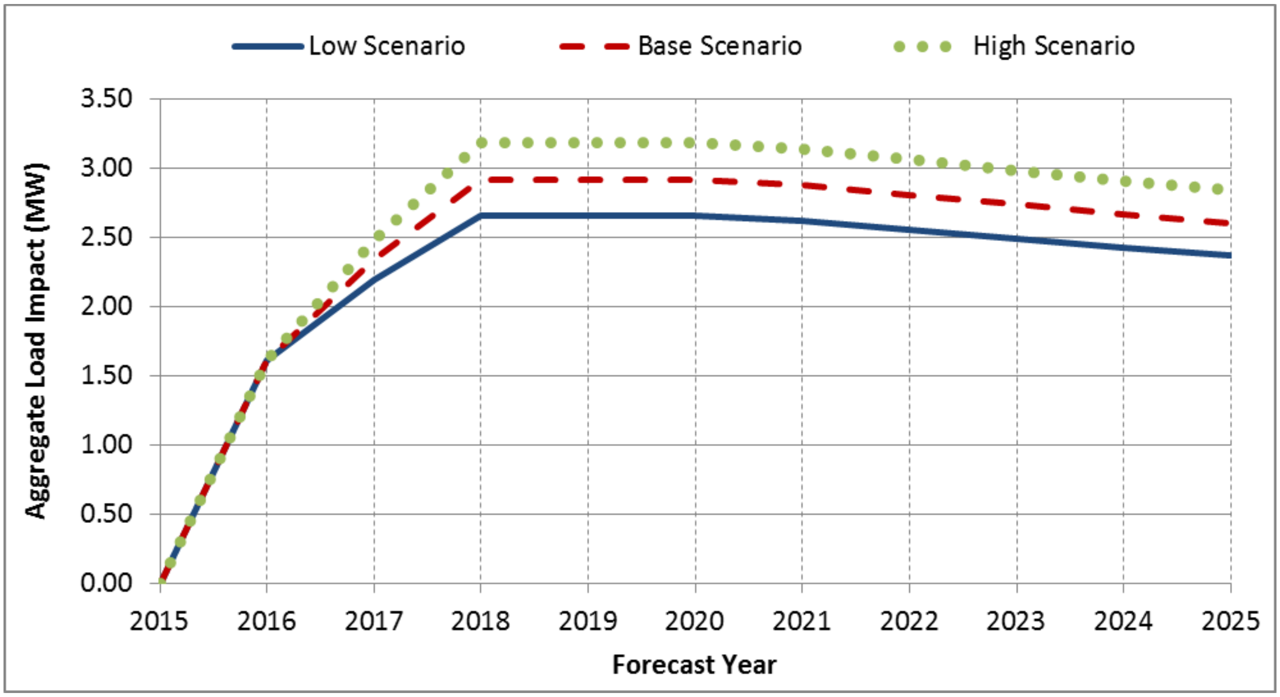
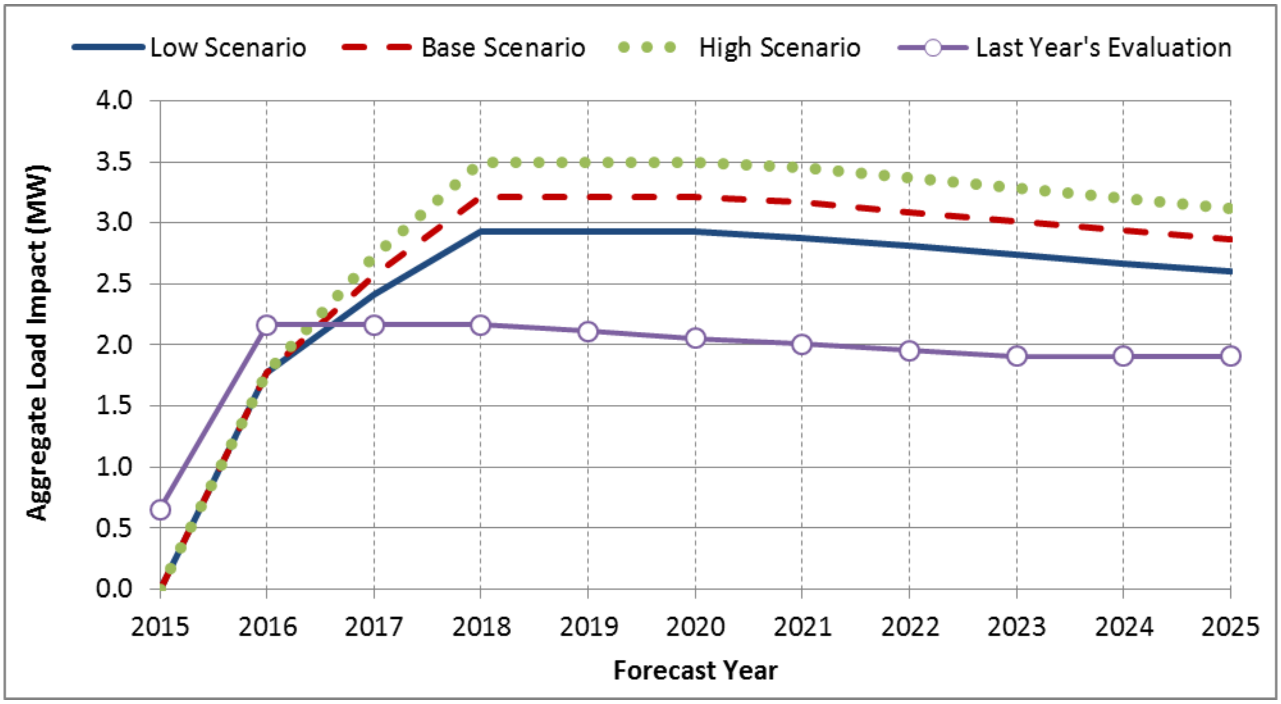


Figure 4-9 compares the ex ante load impact estimates from this evaluation to those from last year's PLS program evaluation, for the August 1-in-10 monthly system peak day. In 2015 and 2016 the ex-ante load impact from this evaluation are lower than those of last year's. This change is based on information from the PLS program applications that SDG&E has received after the program opened in October 2013. Considering that this information was not available at the time, last year's evaluation forecasted that one project would come online before June 2015 and that two additional projects would come online by 2016. Starting in 2016, the increase in impacts is related to the two additional applications that were received in 2014 after last year's evaluation was completed. From 2018 onwards, the load impact estimates for the base scenario are 48% to 58% higher than those of last year's evaluation.

Figure 4-9: SDG&E Comparison of August 1-in-10 Monthly System Peak Day Load Impacts (1 to 6 PM) to Base Scenario from Last Year's PLS Program Evaluation



5 Recommendations

The main recommendation for future program evaluation is to implement a clear and detailed set of EM&V rules to ensure that the utilities know how much load drop they have received and can expect to receive in the future.

Appendix A Methodology for Developing Ex Ante Conversion Factors

As described in Section 2, the PLS program kW load shift amount for incentive calculations for unidentified projects represents the peak load shift that can be expected under 1-in-10 year peak weather conditions. In order to comply with the California DR Load Impact Protocols, this evaluation must convert the forecasted load shift under 1-in-10 peak weather conditions to the ex ante load impact estimates for monthly system peak days and average weekdays under 1-in-2 and 1-in-10 year weather conditions.

At a high level, this is accomplished by 1) developing new generalized building simulation models calibrated to the weather conditions in each LCA; 2) applying updated localized ex ante weather data to the models; and 3) calculating the conversion factors based on the building simulation model output for each LCA from the ratio between chiller load under ex ante weather conditions to peak chiller load under the weather conditions used to calculate the program incentive. The following sections discuss each of the steps in further detail and document the key assumptions and challenges associated with the exercise.

A.1 Development of New Building Simulation Models

Due to new evaluation requirements to report load impacts by CAISO system peak in addition to the utility system peak, Nexant and the IOUs determined the best approach would be to use new building simulation model runs to develop updated conversion factors. For this building simulation modeling work, the evaluation team used the Quick Energy Simulation Tool (eQUEST), which is a software package designed in collaboration with the Department of Energy (DOE) and Lawrence Berkeley National Laboratory (LBNL).[21] This software is used extensively throughout the industry to simulate building energy use for a wide variety of climates, building types and cooling technologies (including various TES designs).

A.1.1 Building Specifications

A single, 2008 vintage Title 24 compliant building simulation model was developed to represent large C&I customers in California. Based on analysis of the applications received to date, the initial model was designed to represent a 3-story commercial office building sized at 500,000 square feet. As is discussed later in this section, the specific characteristics of the initial building model are not critical. The model was calibrated such that the cooling load for the building simulation was appropriately sized for the climatic conditions in each of the 12 LCAs across the three IOUs. The eQUEST software allows Nexant to predict total building cooling load for a chilled water system (including both chiller and fan) based on specified weather conditions, building size, number of stories, orientation (North, South, etc.), the amount of glazing and location.

Fortunately, not knowing specific building characteristics does not affect the accuracy of the load impact estimates by noting that the designed peak shift values, not the raw building simulation model output, were used as the main anchor for load impacts. Nexant only used the simulation software to determine what the ratios were between the cooling load under

[21] eQUEST, <http://www.doe2.com/equest/>

conditions used to determine the incentive payment, and under the ex ante weather conditions for a given building. At no point in the analysis did Nexant directly use simulation software to estimate the overall level of demand shifting at a given site. These values were assumed in the enrollment forecast. The simulation software was only used to answer questions such as, "if I have a site that provides 100 kW of shifting under the incentive payment calculation conditions, then how much does the same site provide under July 1-in-2 conditions?" The ex ante conversion factors answered this question.

Nexant provides evidence that it is not necessary to know the specific building characteristics in Table A-1, which shows that relative usage values across different weather conditions are basically insensitive to building characteristics. The table shows the ratio of average chiller load from 1 to 6 PM between the indicated temperature profile and August 1-in-10 peak conditions for a variety of building characteristics (which are provided in more detail in Table A-2). The point of Table A-1 is that the ratio for a given ex ante condition hardly changes as the building characteristics vary substantially. For example, the ratio of the average chiller load under September 1-in-10 conditions to the average chiller load under August 1-in-10 conditions only varies from 0.89 to 0.91, depending on whether the building is half its original size or twice its original size, whether it has its original window-to-wall ratio or twice that ratio, or whether it has one story versus four stories. This suggests that relative usage levels in the tool are determined primarily by temperature conditions, with the building characteristics driving the overall level of usage. There is only one major deviation from this pattern, under May 1-in-2 conditions, where the values vary from 0.82 to 0.70. Given the uncertainty associated with the other inputs into the estimates, this small inconsistency seems minor.

Having established that it is possible to use the building simulation models to determine relative usage levels without regard to the specific building characteristics, the next key assumptions are focused on the attributes of TES installations to be modeled.

Table A-1: Conversion Factors for a Variety of Building Characteristics Under Each Set of Ex Ante Peak Weather Conditions[22]

	Baseline*	1 in 2 Typical	1 in 2 May	1 in 2 Jun.	1 in 2 Jul.	1 in 2 Aug.	1 in 2 Sep.	1 in 10 Typical	1 in 10 May	1 in 10 Jun.	1 in 10 Jul.	1 in 10 Aug.	1 in 10 Sep.
Original Building	0.46	0.92	0.80	0.86	0.98	0.92	0.93	0.97	0.90	0.93	1.02	1.00	0.90
Twice the Size	0.48	0.92	0.80	0.87	0.98	0.91	0.95	0.98	0.91	0.95	1.01	1.00	0.91
Half the Size	0.44	0.92	0.82	0.87	0.96	0.92	0.93	0.96	0.90	0.93	1.01	1.00	0.90
Four Floors	0.46	0.92	0.70	0.83	0.99	0.91	0.94	0.96	0.89	0.93	1.02	1.00	0.89
Twice the Window to Wall Ratio	0.45	0.92	0.80	0.87	0.98	0.92	0.93	0.97	0.90	0.93	1.02	1.00	0.90

Ex ante conversion factor = average kWh usage between 1–6 PM divided by average kWh usage during 1–6 PM on a typical August 1-in-10 day.

*Baseline is the default temperature profile on July 1 for California Climate Zone 12. It is not a monthly peak day.

22 This table and the associated conversion factors are from the PY2013 evaluation, and provided for comparative purposes in this appendix only.

Table A-2: Characteristics of Buildings in Table A-1[23]

Building Type	Footprint (sq. ft)	Stories	Orientation	Window to Wall Ratio				Climate Zone
				North	*East*	*South*	*West*	
Original Building	10,568	1	North	0.16	0.28	0.20	0.23	12
Twice the Size	21,141	1	North	0.16	0.28	0.20	0.23	12
Half the Size	5,329	1	North	0.16	0.28	0.20	0.23	12
Four Floors	10,568	4	North	0.16	0.28	0.20	0.23	12
Twice the Window to Wall Ratio	10,568	1	North	0.32	0.56	0.40	0.46	12

A.1.2 Treatment of Space and Process Cooling Installations

The utilities have received a combination of space and process cooling applications to date. The ideal situation would be to develop generalized models for both space and process cooling installations. However, process cooling installations are each unique to their specific industry, and may also exhibit seasonality in industries related to agriculture or food processing. The load shapes from the building simulation models for the existing PG&E applications were reviewed and confirm both industry specific load shapes and seasonality. Figure A-1 is an example of a food processing facility with limited energy consumption between November and March. Figure A-2 is an example of a winery with twice the typical load during the harvest season. Due to these factors, existing process cooling installations do not make good candidates for generalized modeling that could represent all future process cooling applications.

[23] This table and the associated conversion factors are from the PY2013 evaluation, and provided for comparative purposes in this appendix only.

Figure A-1: Seasonal Load Shape

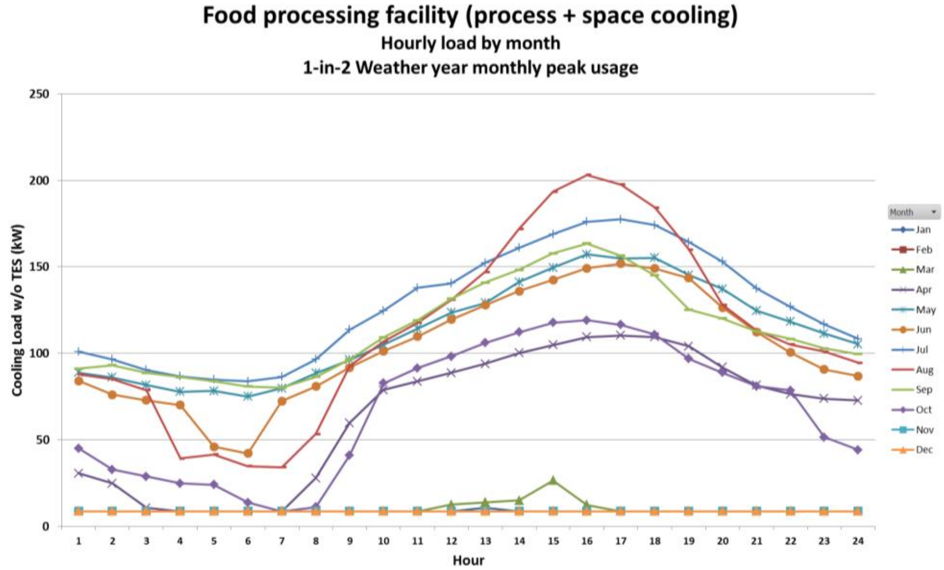
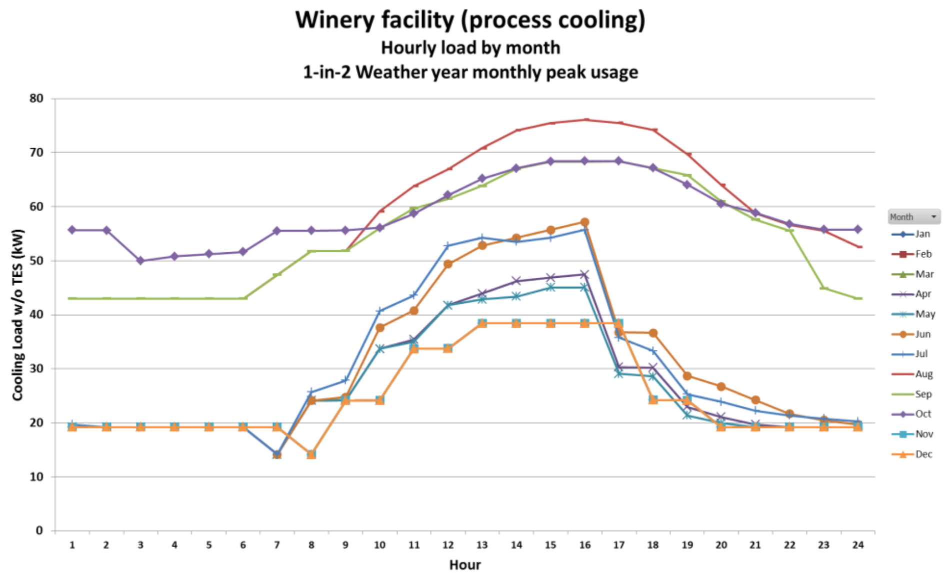


Figure A-2: Seasonal Load Shape



To determine the best method to account for process cooling installations, the weather sensitivity of the existing applications was analyzed. The customer usage data forecast from the building simulation models under 1-in-2 and 1-in-10 monthly IOU system peak conditions was calculated. The percentage difference in hourly usage under the 1-in-2 and 1-in-10 conditions was then calculated to determine the level of weather sensitivity of the process cooling load. A range of results up to approximately 20% was observed, indicating that process cooling load is weather sensitive. To provide a basis for comparison, PG&E's commercial SmartAC program exhibits a similar upper bound of approximately a 20% difference in cooling load between 1-in-2 and 1-in-10 monthly system peak conditions.

Due to the industry-specific load shape and seasonality of process cooling installations not being generalizable, and the weather sensitivity being comparable to commercial space cooling, it was reasonable to apply the conversion factors developed for the unidentified space cooling projects to the unidentified process cooling installations.

A.1.3 Percentage of TES Offset to Total Cooling Load

TES system capacity can vary based on the individual need for each project site. Previous evaluations have assumed that the TES system for unidentified projects is sized to offset the full chiller load under peak conditions. An alternative possibility is that the system is designed to shift only part of the chiller load under peak conditions. This distinction is referred to as full versus partial storage.

Now that feasibility studies are available for several project applications, assumptions are being revisited and updated as necessary. Based on the combination of applications and feasibility studies available for review, 7 of the 9 projects with available information are designed to shift between 95% and 100% of the maximum peak cooling load. For example, if the maximum cooling load for a building is 100 tons, a TES system designed for a 100% offset would be sized at approximately 600-ton hours to offset the cooling load of 100 tons for the required 6-hour period.

At this time, none of the projects have been completed, and most are still in the planning stages. When additional data on the type of projects that are actually installed becomes available, it will be good to revisit this assumption. However, at this time there is not enough evidence to warrant changing the expected offset from the full to the partial storage scenario.

To the extent that the partial storage alternative is applicable for some sites, the ex ante impact estimates for cooler weather conditions might be understated because under the current assumptions, load shift falls as temperature and the corresponding load decreases. Under partial storage, the load shift might be constant over some range of ex ante weather conditions at the hotter end of the weather spectrum. Because Nexant began with the designed peak shift as the main input, and because the designed peak shift takes place under conditions similar to the hottest ex ante conditions, the assumption is unlikely to have a significant effect on the accuracy of load impact estimates under the hottest weather conditions. Additionally, to the degree that it is inaccurate for cooler conditions, the results are conservative and tend to understate load impacts under those conditions. Given the uncertainty of the other components of the forecast such as the type and number of applicants, it was reasonable to maintain the full storage assumption until additional information becomes available.

A.2 Updated Ex Ante Weather Conditions

Nexant developed updated ex ante weather conditions to meet the new requirement for reporting load impacts by CAISO system peak in addition to the utility system peak. The new ex ante weather data incorporated the most recent weather data available and was used for inputs in all of the building simulation models.

The building simulation modeling was completed at the LCA level, requiring ex ante weather data that accurately represented conditions in each LCA. Some LCAs had multiple weather stations, and in those cases, Nexant developed a weighted ex ante weather file based on the proportion of customers similar in size to existing PLS applicants assigned to each weather station within an LCA. Aggregating and weighting the weather before running the model rather than running the building simulation models for each weather station minimized the number of costly building simulation runs.

The cooling load for each LCAs building simulation model was calibrated using the new ex ante weather data such that the modeled cooling equipment was appropriate for the local weather conditions. The 1-in-10 peak conditions for each LCA was the hottest weather input, and thus determined the maximum cooling load and associated peak load shift for each simulation model. This enabled the 1-in-10 peak day weather conditions to stand as a proxy for the conditions an engineer would have used to determine the maximum peak load shift for the incentive calculation. In other words, incentives would have always been calculated based on the peak load shift on the hottest day for a facility, and by design, the 1-in-10 peak day represented those conditions in the building simulation model.

A.3 Building Simulation Runs

Nexant used the building simulation model described in section A.1.1 along with the assumptions discussed in the remainder of appendix A and applied it as the representative building for determining relative usage levels under different conditions. Nexant then estimated cooling load for that building under the following conditions for each LCA:

- 1-in-10 maximum impact utility specific peak day as a proxy for incentive payment calculation conditions; and
- Ex ante weather conditions for each month of the year, for system peak day and average weekday, for 1-in-2 years and 1-in-10 years, for the utility and for CAISO.

A.4 Conversion Factor Calculations

The output from the eQUEST model was the estimated chiller load for each hour of the day under each of the conditions listed in A.3. Since these estimates were for a representative building, they do not necessarily bear any relation to the projected peak shifting values from the enrollment forecast. Nexant then applied the ratio of the eQUEST predicted loads under each set of ex ante conditions to the eQUEST predicted loads under the 1-in-10 peak day (as a proxy for incentive payment calculation conditions). These ratios were used as the conversion factors described in Section 2. To ensure load reductions in the ex ante tables did not exceed the maximum load impact specified under the incentive payment conditions, the conversion factor ratios were restricted to a maximum value of 1.

Table A-3: Summary of Ex Ante Conversion Factors for 1-in-2 and 1-in-10 Monthly System Peak Days (Ratios between peak PLS impact under ex ante conditions and Utility Specific annual maximum 1-in-10 monthly system peak day PLS impact)

Peak Type	Utility	LCA	May		June		July		August		September		October	
			1-in-2	1-in-10	1-in-2	1-in-10	1-in-2	1-in-10	1-in-2	1-in-10	1-in-2	1-in-10	1-in-2	1-in-10
Utility Specific	PG&E	All	0.84	0.91	0.91	0.96	0.94	1.00	0.93	0.98	0.91	0.94	0.81	0.84
		Greater Bay Area	0.84	0.94	0.90	0.96	0.93	1.00	0.92	0.98	0.92	0.95	0.82	0.86
		Greater Fresno	0.83	0.85	0.93	0.92	0.96	0.99	0.93	1.00	0.88	0.89	0.80	0.79
		Humboldt	0.80	0.89	0.85	0.95	0.93	1.00	0.95	0.96	0.92	0.95	0.78	0.87
		Kern	0.90	0.71	0.95	0.92	0.94	1.00	0.94	0.98	0.91	0.92	0.81	0.83
		Northern Coast	0.84	0.93	0.91	1.00	0.95	0.98	0.92	0.98	0.91	0.96	0.84	0.88
		Other	0.84	0.92	0.92	0.95	0.95	1.00	0.93	0.99	0.91	0.94	0.80	0.84
		Sierra	0.84	0.90	0.92	0.93	0.93	1.00	0.92	0.95	0.88	0.90	0.77	0.81
		Stockton	0.84	0.90	0.91	0.93	0.96	1.00	0.96	0.97	0.88	0.90	0.74	0.79
	SCE	All	0.81	0.86	0.85	0.91	0.93	1.00	0.93	0.99	0.90	0.97	0.81	0.87
		LA Basin	0.82	0.87	0.85	0.92	0.94	1.00	0.94	1.00	0.92	1.00	0.83	0.88
		Outside LA Basin	0.80	0.82	0.83	0.87	0.92	1.00	0.89	0.96	0.82	0.89	0.75	0.79
		Ventura	0.79	0.83	0.84	0.91	0.92	1.00	0.89	0.96	0.84	0.90	0.78	0.85
	SDG&E		0.74	0.84	0.77	0.83	0.76	0.98	0.85	0.93	0.80	1.00	0.85	0.87
CAISO Specific	PG&E	All	0.84	0.88	0.93	0.93	0.93	1.00	0.88	0.94	0.87	0.90	0.82	0.84
		Greater Bay Area	0.84	0.89	0.93	0.94	0.90	1.00	0.90	0.92	0.85	0.89	0.86	0.84
		Greater Fresno	0.86	0.87	0.90	0.92	0.96	0.99	0.86	0.97	0.88	0.91	0.75	0.83
		Humboldt	0.81	0.83	0.88	0.88	0.88	1.00	0.84	0.93	0.85	0.86	0.79	0.83
		Kern	0.86	0.89	0.94	0.91	0.97	1.00	0.86	0.98	0.90	0.88	0.78	0.85
		Northern Coast	0.80	0.90	0.94	0.93	0.92	1.00	0.87	0.94	0.88	0.92	0.84	0.85
		Other	0.85	0.86	0.92	0.94	0.94	1.00	0.87	0.96	0.87	0.91	0.80	0.86
		Sierra	0.83	0.84	0.90	0.91	0.94	0.98	0.84	0.94	0.85	0.86	0.77	0.82
		Stockton	0.87	0.83	0.92	0.92	0.95	0.98	0.85	0.95	0.87	0.87	0.73	0.80
	SCE	All	0.82	0.87	0.87	0.91	0.99	1.00	0.91	0.98	0.92	0.97	0.80	0.90
		LA Basin	0.82	0.87	0.87	0.92	0.99	1.00	0.92	0.98	0.94	0.99	0.81	0.91
		Outside LA Basin	0.82	0.81	0.87	0.89	0.99	0.99	0.89	0.96	0.86	0.87	0.75	0.83
		Ventura	0.82	0.87	0.88	0.91	0.97	1.00	0.89	0.95	0.90	0.93	0.78	0.85
	SDG&E		0.65	0.88	0.72	0.85	0.81	0.78	0.86	0.90	0.97	1.00	0.77	0.88

Appendix B PG&E Building Simulation Modeling from PY2013 PLS Evaluation

PG&E had three active applications as of this writing, with a wide range of expected peak load shifts. All of the projects included process cooling loads. Given the variation of these projects across cooling load size and industry type, and the fact that a single project is expected to deliver a large portion of the load shift, PG&E chose to use building simulation modeling to estimate the ex ante load impacts for identified projects.

The remainder of this section summarizes the step-by-step approach that was applied to the three remaining identified PG&E projects.

Step 1: Populate Initial eQUEST inputs

To populate the initial eQUEST inputs, Nexant used information from the PLS program applications, PG&E data, discussions with the PLS program manager and, in some cases, discussions with the utility account representative and/or customer. These initial eQUEST inputs included the following:

- Facility square footage;
- Type of cooling (process/space);
- Type of thermal energy storage to be installed;
- Capacity of thermal energy storage tank;
- Number of thermal energy storage tanks;
- Thermal energy storage charge/discharge schedule;
- Chiller capacity;
- Chiller type (air-cooled/water cooled, centrifugal/screw/reciprocating);
- Chiller supply temperature;
- Chiller operation schedule;
- Project site address;
- North American Industry Classification System (NAICS) code;
- Rate schedule;
- LCA;
- Assigned weather station;
- 2013 hourly temperature data; and
- 2013 hourly usage data.

Step 2: Calibrate eQUEST Model

Using these initial eQUEST inputs, Nexant predicted each building's 2013 hourly usage based on the 2013 hourly temperatures for each customer. This initial model prediction was compared to the actual 2013 hourly usage in order to assess the accuracy of the model. Then, Nexant calibrated the model by adjusting some of the default eQUEST inputs. In addition to the inputs described above, eQUEST includes other variables that affect the model predictions. The calibration process involved adjusting some of the default values for those other variables, based on the 2013 building usage patterns and, in some cases, other information such as satellite imagery from Google maps. The inputs that were adjusted in the calibration process included:

- Lighting load density (W/sq. ft.);
- Lighting operating schedule (weekly operating hours);
- Building equipment/plug load density (W/sq. ft.);
- Equipment/plug load operating schedule (weekly operating hours);
- Process load (kW);
- HVAC system operating schedule (weekly operating hours);
- Air handling unit (AHU) fan static pressure;
- Minimum outside air flow ratio for AHUs (%);
- Design air flow rate for variable air volume (VAV) boxes;
- Minimum air flow ratio for VAV boxes (%); and
- Space temperature set point (°F).

Ideally, Nexant would have visited the facility in order to populate these remaining inputs, but given that customers are scheduled to go through a similar process as part of the feasibility study, the evaluation team did not want to impose additional burden on PLS program applicants. Either way, this calibration process is common for building simulation modeling, even when more in-depth information is available.

Regardless of some data limitations, the calibrated eQUEST models produced highly accurate predictions of hourly and monthly building usage for the identified PLS facilities. Figure B-1 provides a comparison of the simulated and actual 2013 monthly building usage for identified PLS facilities. From May through October, the months in which the PLS-TES system was operated, the simulated building usage fell within 5% of the actual usage. Similarly, Figure B-2 shows how simulated and actual 2013 hourly building usage compare during the summer time period (May through October). With hourly usage that falls within 3% of the actual usage, the building simulations are also quite accurate across the hours of the day during the summer. Therefore, while the building simulation modeling work would have ideally involved a site visit, by calibrating the model to 2013 hourly interval data, Nexant was able to develop models that accurately reflect how each building's usage varies by temperature throughout the day and year. Therefore, Nexant has confidence that the model accurately predicts the underlying cooling usage.

Figure B-1: Comparison of Simulated and Actual 2013 Monthly Building Usage for Identified PLS Facilities

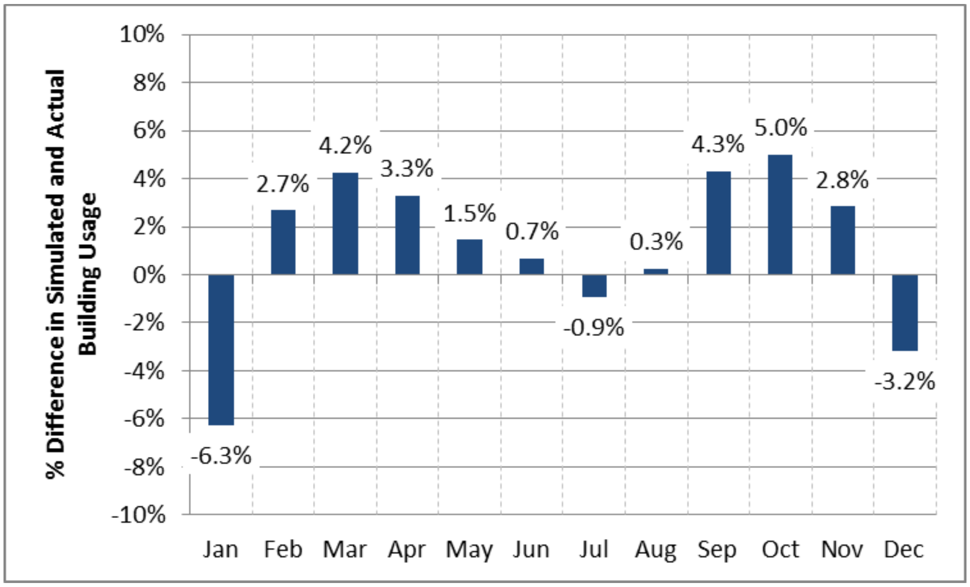
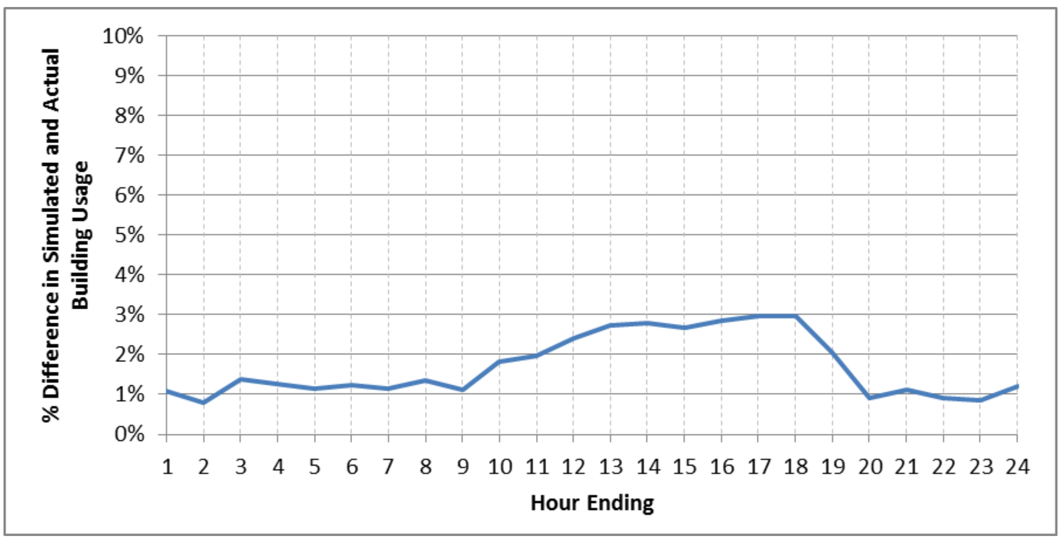


Figure B-2: Comparison of Simulated and Actual 2013 Hourly Building Usage for Identified PLS Facilities (May through October)



Step 3: Predict Cooling Usage Under Ex Ante Weather Conditions

The final step was to predict cooling usage with and without the PLS-TES system, under the ex ante weather conditions that are required by the DR load impact protocols. By subtracting the cooling usage with the PLS-TES system from the cooling usage without the PLS-TES system, Nexant estimated the hourly impacts for each ex ante weather condition. As a result, the forecast for these identified PG&E projects did not rely on the ex ante conversion factors described in Appendix A. Finally, considering that the location and installation date are known for these projects, the forecast incorporates this information by having the project come online on the expected installation date and by assigning the ex ante load impacts for that project to the customer's LCA.