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Final Report: SGIP 2014-2015 Impacts Evaluation Report Submitted by the National Fuel Cell Research Center

Additional submitted attachment is included below.

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June 09, 2017

California Energy Commission
MS Dockets Office, MS-4
Re: Docket No. 17-IEPR-07
1516 Ninth Street
Sacramento, CA 95814-5512

Re: IEPR Integrated Resource Planning for Renewable Fuel Cell Applications

The National Fuel Cell Research Center (NFCRC) submits the attached "Final Report: SGIP 2014-2015 Impacts Evaluation Report" for consideration in the IEPR Integrated Resource Planning Docket (17-IEPR-07).

This report was submitted by Itron to SoCalGas and the Self-Generation Incentive Program (SGIP) Working Group, September 29, 2016. Per the Document Summary:

> The original CPUC Decision (D.) 01-03-073 establishing the SGIP required "program evaluations and load impact studies to verify energy production and system peak demand reductions" resulting from the SGIP. That March 2001 decision also directed the assigned Administrative Law Judge (ALJ), in consultation with the CPUC Energy Division (ED) and the PAs, to establish a schedule for filing the required evaluation reports. Since 2001, thirteen annual SGIP impact evaluations have been conducted.
>
> The SGIP has evolved to meet the changing energy and policy needs of California. Annual SGIP impact evaluation reports in turn have reflected changes in SGIP eligibility criteria and success metrics. The primary purpose of this report is to quantify the energy, demand, and environmental impacts of the SGIP during calendar years 2014 and 2015. Impacts are reported for the SGIP as a whole and by other categories such as technology type, fuel type, PA and electric utility. Some presorted impacts are further categorized by program year to recognize the different program goals and rules in effect at the time of project development.

This report further demonstrates to the Integrated Resource Planning (IRP) Docket #17-IEPR-07 of the California Energy Commission's (CEC) Integrated Energy Policy Report (IEPR) the importance of recognizing GHG-reducing fuel cells as a critical technology needed to complement and manage the high penetration of intermittent solar and wind, cornerstones in achieving the California 40% GHG emissions reduction goal by 2030.

Sincerely,

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Final Report:
2014-2015 SGIP
Impacts Evaluation

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SoCalGas and the
SGIP Working Group

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November 4, 2016

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GLOSSARY AND KEY TERMS

Acronyms and Abbreviations

Term	Definition
AES	Advanced Energy Storage
CAISO	California Independent System Operator
CEC	California Energy Commission
CSE	Center for Sustainable Energy
CO_2	Carbon dioxide
CO_2eq	CO_2 equivalent
CPUC	California Public Utilities Commission
DER	Distributed energy resource
FC	Fuel cell
GT	Gas turbine
ICE	Internal combustion engine
IOU	Investor-owned utility
MCS	Monte Carlo Simulation
MT	Microturbine
NEM	Net energy metering
NO_X	Nitric oxide (NO) and nitrogen dioxide (NO_2)
PA	Program Administrator
PBI	Performance based incentive
PG&E	Pacific Gas and Electric Company
PM_{10}	Particulate matter (PM) with diameter of 10 micrometers or less
PPA	Power Purchase Agreement
PRT	Pressure reduction turbine
PY	Program Year
SCE	Southern California Edison Company
SCG	Southern California Gas Company
SDG&E	San Diego Gas and Electric Company
SO_2	Sulfur Dioxide
SGIP	Self-Generation Incentive Program
WD	Wind turbine

Glossary

Term	Definition
Applicant	The entity, either the Host Customer, System Owner, or third party designated by the Host Customer, that is responsible for the development and submission of the SGIP application materials and is the main contact for the SGIP Program Administrator for a specific SGIP application.
Biogas	A gas composed primarily of methane and carbon dioxide produced by the anaerobic digestion of organic matter. This is a renewable fuel. Biogas is typically produced in landfills, and in digesters at wastewater treatment plants, food processing facilities, and dairies.
Biogas Baseline	The assumed treatment of biogas fuel in the absence of the SGIP generator. See Flaring and Venting.
California Independent System Operator (CAISO)	A non-profit public benefit corporation charged with operating the majority of California's high-voltage wholesale power grid.
Capacity Factor	A measure of system utilization that is calculated as the ratio of electrical energy generated to the electrical energy that would be produced by the generating system at rebated capacity during the same period (e.g., hourly, annually)
Combined Heat and Power (CHP)	A system that produces both electricity and useful heat simultaneously; sometimes referred to as "cogeneration."
CO2 Equivalent (CO2eq)	When reporting emission impacts from different types of greenhouse gases, total GHG emissions are reported in terms of tons of CO2 equivalent so that direct comparisons can be made. To calculate CO2eq, the global warming potential of a gas as compared to that of CO2 is used as the conversion factor (e.g., the global warming potential (GWP) of CH4 is 21 times that of CO2). Thus, the CO2eq of a given amount of CH4 is calculated as the product of the GWP factor (21) and the amount of CH4.
Commercial	Non-manufacturing business establishments, including hotels, motels, restaurants, wholesale businesses, retail stores, and for-profit health, social, and educational institutions.
Completed	Projects that have been installed and begun operating, have passed their SGIP eligibility inspection, and were issued an incentive payment.
Confidence Interval	A particular kind of interval estimate of a population parameter (such as the mean value) used to indicate the reliability of the estimate. It is an observed interval (i.e., calculated from observations) that frequently includes the parameter of interest. How frequently the observed interval contains the parameter is determined by the confidence level or confidence coefficient. A confidence interval with a particular confidence level is intended to give the assurance that, if the statistical model is correct, then taken over all the data that might have been obtained, the procedure for constructing the interval would deliver a confidence interval that included the true value of the parameter the proportion of the time set by the confidence level.
Confidence Level (also Confidence Coefficient)	The degree of accuracy resulting from the use of a statistical sample. For example, if a sample is designed at the 90/10 confidence (or precision) level, resultant sample estimates will be within ±10 percent of the true value, 90 percent of the time.
Decommissioned	Projects that have been retired from service and the equipment removed.

Term	Definition
Directed Biogas	Biogas delivered through a natural gas pipeline system and its nominal equivalent used at a distant customer's site. Within the SGIP, this is classified as a renewable fuel.
Electrical Conversion Efficiency	The ratio of electrical energy produced to the fuel energy used (lower heating value).
Flaring (of Biogas)	A flaring baseline means that there is prior legal code, law or regulation requiring capture and flaring of the biogas. In this event an SGIP project cannot be credited with GHG emission reductions due to capture of methane in the biogas. A project cannot take credit for a prior action required by legal code, law or regulation. See also: Venting (of Biogas).
Greenhouse Gas (GHG) Emissions	For the purposes of this analysis GHG emissions refer specifically to those of CO2 and CH4, expressed as CO2eq.
Heat Rate	The amount of input energy used by an electrical generator to generate one kilowatt-hour (kWh) of electricity. Heat rate is commonly defined using units such as Btu/kWh.
Higher Heating Value (HHV)	The amount of heat released from combustion of fuel when all the products of combustion are brought back to the original pre-combustion temperature, and in particular condensing any vapor produced. Units of HHV are typically Btu/SCF of fuel.
Lower Heating Value (LHV)	The amount of heat released from combustion of fuel assuming that the water produced during the combustion process remains in a vapor state at the end of combustion. Units of LHV are typically Btu/SCF of fuel.
Load	Either the device or appliance which consumes electric power, or the amount of electric power drawn at a specific time from an electrical system, or the total power drawn from the system. Peak load is the amount of power drawn at the time of highest system demand.
Marginal Heat Rate	The marginal heat rate is the amount of source energy that is saved as a result of a change in generation.
Metric Ton	Common international measurement for the quantity of greenhouse gas emissions. A metric ton is equal to 2,205 pounds.
Offline	Projects with an annual capacity factor less than 0.05.
Online	Projects with an annual capacity factor of at least 0.05. Online projects are considered connected to the grid and providing power to the grid.
Onsite Biogas	Biogas projects where the biogas source is located directly at the host site where the SGIP system is located. See also: Directed Biogas.
Performance	A general reference to the operational effectiveness of an SGIP system. See also: electrical conversion efficiency and utilization.
Prime Mover	A device or system that imparts power or motion to another device such as an electrical generator. Examples of prime movers in the SGIP include gas turbines, IC engines, and wind turbines.
Rebated Capacity	The capacity rating associated with the rebate (incentive) provided to the program participant. The rebated capacity may be lower than the manufacturer's nominal "nameplate" system size rating. See also: system size.
Recoverable Heat	The amount of heat available for recovery from a CHP system after generation of electricity. If heat load at the host site is lower than the amount of recoverable heat, the useful heat will be less than the recoverable heat.

Term	Definition
System Efficiency	The unit-less ratio of useful energy produced to the fuel energy used (lower heating value).
System Owner	The owner of the SGIP system at the time the incentive is paid. For example, in the case when a vendor sells a turnkey system to a Host Customer, the Host Customer is the System Owner. In the case of a leased system, the lessor is the System Owner.
System Size	The manufacturer rated nominal size that approximates the generator's highest capacity to generate electricity under specified conditions.
Useful Heat	Recovered heat actually delivered and used to satisfy the on-site heating demand for a specific process or application at the host site. Useful heat may differ significantly from recoverable heat rates included in CHP manufacturer specifications.
Utilization	A general reference to how much an SGIP system is used. See also: capacity factor, decommissioned, online, and offline.
Venting (of biogas)	A venting baseline means that there is no prior legal code, law or regulation requiring capture and flaring of the biogas. Only in this event can an SGIP project be credited with GHG emission reductions due to capture of methane in the biogas. A project cannot take credit for a prior action required by legal code, law or regulation. See also: Flaring (of Biogas).

1

Executive Summary

1 EXECUTIVE SUMMARY

This report represents an evaluation of the impacts of the Self-Generation Incentive Program (SGIP) for calendar years 2014-2015. The report provides energy, demand, and environmental impacts of the SGIP as estimated for each of the reporting years. Impacts are reported for the SGIP as a whole and by other categories such as technology type, fuel type, Program Administrator (PA), and electric utility. Some reported impacts are further categorized by program year to recognize the different program goals and rules in effect at the time of project development.

Specific objectives for this 2014-2015 evaluation include:

- Energy impacts including electricity generated, fuel consumed, and useful heat recovered. Efficiency and utilization metrics include: annual capacity factor, electrical conversion efficiency, useful heat recovery rate, and system efficiency.
- Energy impacts are treated separately for advanced energy storage (AES) and include breakouts by charge and discharge impacts.
- Utility-oriented peak demand impacts (average reduction and capacity factor) during top demand hour and top 200 hours of the California Independent System Operator (CAISO) and California's three investor owned utilities.
- Noncoincident customer peak impacts that identify the effect of the SGIP systems on customer peak demand; and
- Environmental impacts including those on greenhouse gas (GHG) emissions and criteria air pollutants.

The SGIP includes a significant number of projects that were installed early on in the program and have continued to operate; providing benefits to both the host customer and the utility. As such, while the focus of this report is on impacts occurring during 2014 and 2015, these impacts result from a portfolio of projects with online dates that can span many years. Changes in program policies and requirements have created significant differences in operation and performance of the projects. In particular, Senate Bill 412 (Kehoe, October 11, 2009) established greenhouse gas (GHG) requirements that resulted in substantial changes in performance in CHP technologies installed under the SGIP following SB 412. Where appropriate, we differentiate impacts between pre-SB 412 projects and post-SB 412 projects. Similarly, due to the relatively new emergence of metered data for AES projects installed under the SGIP, difference in operation between generation technologies and storage technologies and the growing importance of AES within the program,[1] we provide a separate section on AES energy impacts. In light of a November 19, 2015 ruling by the CPUC[2] on the effect of the Renewable Portfolio Standard (RPS) on GHG emissions from SGIP projects, we have also incorporated a scenario estimate of GHG emissions assuming existing SGIP projects were subject to the GHG emission eligibility requirement.

Impact evaluations are useful in assessing actual versus expected performance of a program and the associated measures (or technologies). As such, impact evaluations can help identify where corrective

[1] In the May 16, 2016 proposed decision "Decision Revising the Self-Generation Incentive Program Pursuant to Senate Bill 861, Assembly Bill 1478, and Implementing Other Changes," the CPUC allocated 75% of the SGIP incentive budget going forward to AES.

[2] Decision 15-11-027, http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M156/K044/156044151.PDF

actions should be considered by policy makers. To help put the different impact estimates into perspective, we compare pre-SB 412 versus post-SB 412 project impacts; non-storage versus storage (AES) impacts; and GHG emissions with and without the RPS build margin taken into account.

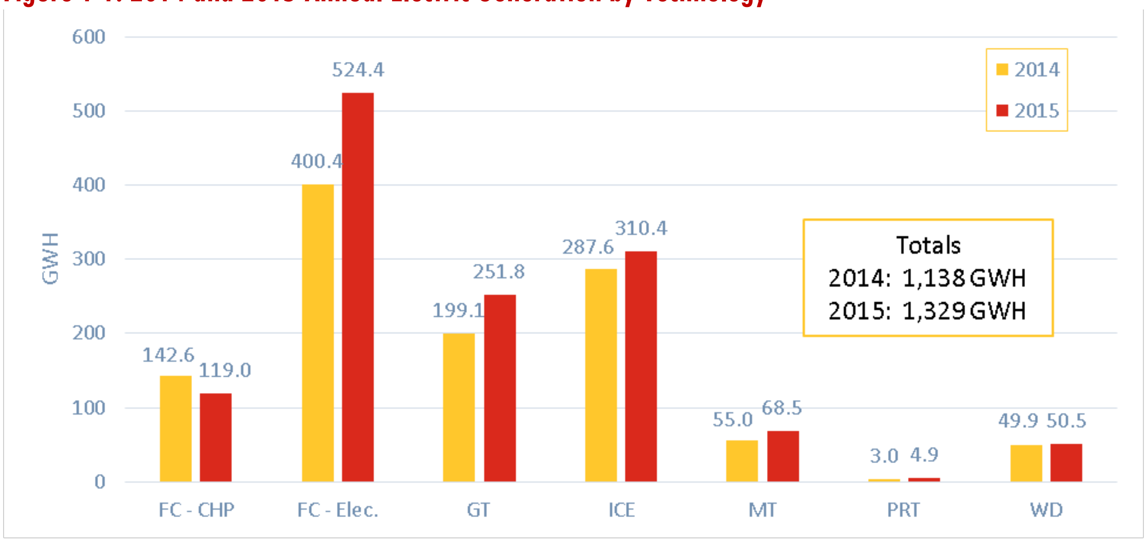
1.1 SGIP Impacts at 2014-2015

By the end of 2015, SGIP had provided incentives to 1,144 completed projects[3] representing over 440 MW of rebated capacity. Over $656 million in incentives were provided to completed projects[4] while eligible costs[5] of projects reported by SGIP applicants surpassed $2.3 billion. Additional information on SGIP project counts, capacities and costs can be found in Section 3 (Background and Status).

Non-AES Energy and Demand Impacts for 2014-2015

SGIP projects generated over 1 Terawatt Hour (TWh) of electricity annually in both 2014 and 2015; this represents approximately 0.5 percent of California's 2015 total in-state generation.[6] Figure 1-1 shows the SGIP electricity generation contributions during 2014 and 2015 by technology type.

Figure 1-1: 2014 and 2015 Annual Electric Generation by Technology



FC-CHP = Fuel Cell-Combined Heat and Power; FC-Elec = Fuel Cell-All Electric; GT = Gas Turbine, ICE = Internal Combustion Engine, MT = Microturbine, PRT = Pressure Reduction Turbine, WD = Wind Turbine

3 The scope of this impact evaluation is limited to 'completed' projects. Completed projects have been installed and begun operating, have passed their eligibility inspection, and were issued an incentive payment on or before December 31, 2015.

4 Although the SGIP provided incentives to solar photovoltaic (PV) projects in the past, this impact report, including project counts and capacities, incentives paid and eligible costs does not reflect PV projects.

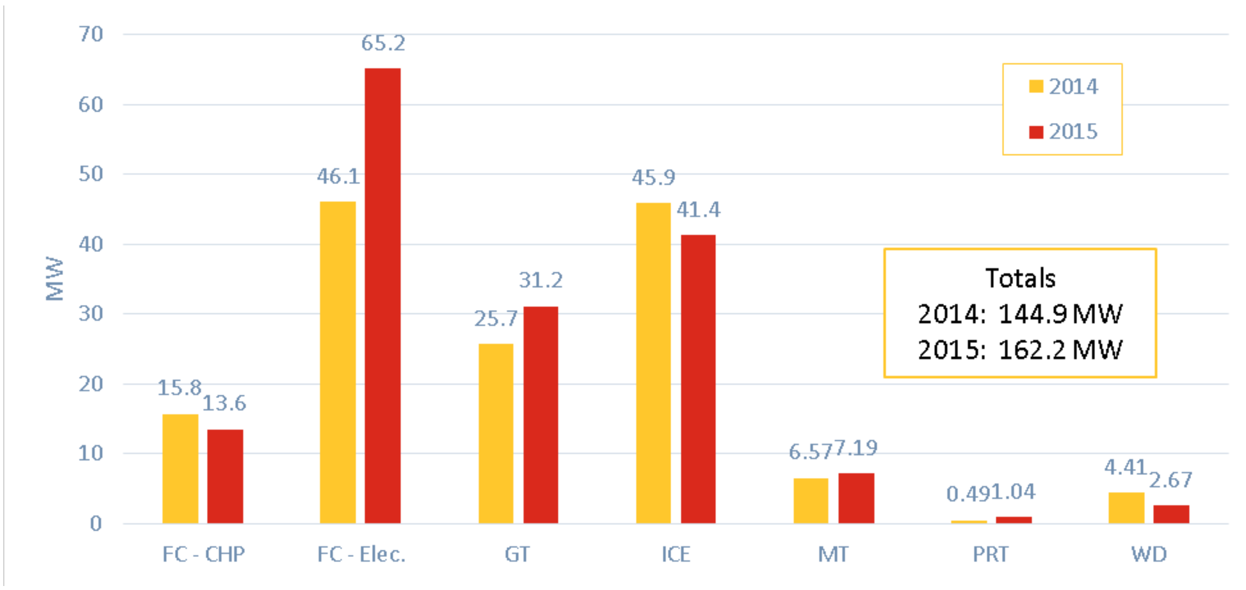
5 In general, eligible costs are project costs required to construct and operate the project, including such items as engineering feasibility costs, engineering and design fees, equipment capital costs, electric and gas interconnection fees, etc. Eligible costs are defined in the SGIP handbook.

6 California's in-state generation in 2015 was 196,195 GWh. From California Energy Almanac, "2015 Total System Power in Gigawatt Hours," http://energyalmanac.ca.gov/electricity/total_system_power.html.

SGIP's electricity generation grew by over 21% between 2014 and 2015. All SGIP technologies increased generation from 2014 to 2015 except CHP-fuel cells, IC engines and Wind. The growth in annual generation between 2014 and 2015 was due primarily to the addition of 69 MW of new generating capacity, all of it representing post-SB 412 projects. At the end of 2015, all-electric fuel cells and IC engines made the largest contributions to SGIP's electricity generation.

SGIP projects that generate electricity during the peak hours of CAISO or IOU loads result in coincident peak demand impacts. Ideally, SGIP projects generate at full capacity during these peak hours, thereby reducing utility need to generate and transfer power to meet peak electricity demands. As shown in Figure 1-2, SGIP generation occurring coincident to the 2014 and 2015 CAISO peak hour represented approximately 145 MW and 162 MW, respectively.[7] The greatest contribution of electricity from SGIP during the CAISO 2014 and 2015 peak hour resulted from all-electric fuel cells.

Figure 1-2: 2014 and 2015 CAISO Peak Hours Generation by Technology (MW)



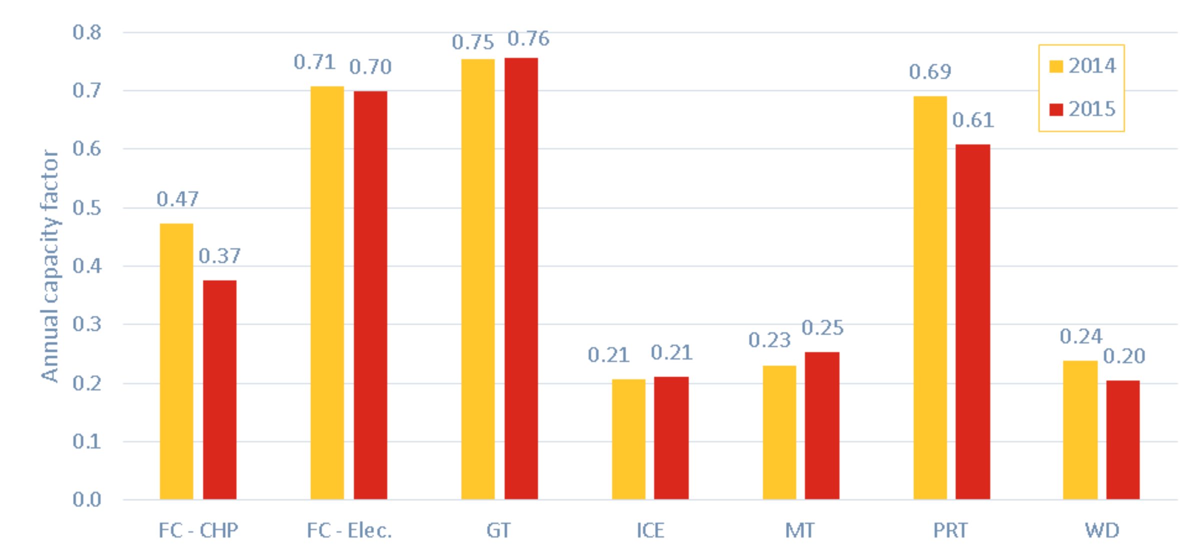
FC-CHP = Fuel Cell-Combined Heat and Power; FC-Elec = Fuel Cell-All Electric; GT = Gas Turbine, ICE = Internal Combustion Engine, MT = Microturbine, PRT = Pressure Reduction Turbine, WD = Wind Turbine

Energy impacts are a function of generating capacity and utilization. Capacity factor is a measure of system utilization. Capacity factor is defined as the amount of energy generated during a given time period divided by the maximum possible amount of energy that could have been generated during that time period. A high capacity factor (near 1.0) indicates that the system is being utilized to its maximum potential. Figure 1-3 depicts the annual average capacity factor for the different SGIP generation

[7] The CAISO hourly peak for 2014 was 45,090 MW occurring on September 15, 2014 at the hour ending 4 pm. The CAISO hourly peak for 2015 was 47,257 MW on September 10, 2015 at hour ending 4 pm. See the CAISO Annual Market Performance Reports for 2014 and 2015 at: http://www.caiso.com/Documents/2014AnnualReport_MarketIssues_Performance.pdf and http://www.caiso.com/Documents/2015AnnualReportonMarketIssuesandPerformance.pdf

technologies during 2014 and 2015. Gas turbines and all-electric fuel cells showed the highest annual capacity factors; generally exceeding 70% during 2014 and 2015.

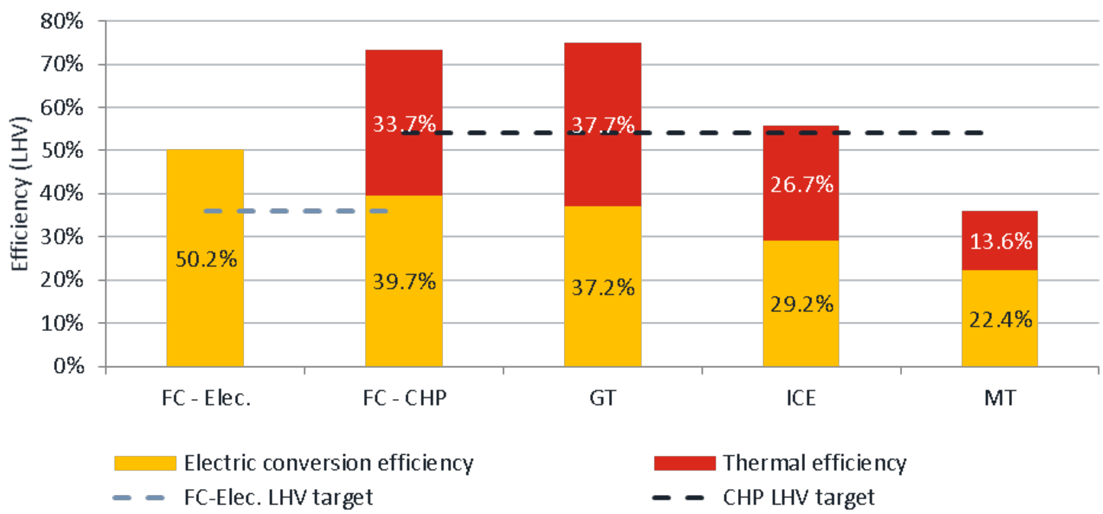
Figure 1-3: 2014 and 2015 Annual Average Capacity Factors by Technology



FC-CHP = Fuel Cell-Combined Heat and Power; FC-Elec = Fuel Cell-All Electric; GT = Gas Turbine, ICE = Internal Combustion Engine, MT = Microturbine, PRT = Pressure Reduction Turbine, WD = Wind Turbine

The system efficiency is defined as the ability to convert fuel into useful electrical and thermal energy. The higher the system's overall efficiency the less fuel input is needed to produce the combination of the generated electricity and useful recovered heat. Figure 1-4 shows the system efficiency as well as the contributions of the electrical and useful thermal components to the system efficiency for SGIP generation technologies for 2014. In general, gas turbines, CHP fuel cells and IC engines exhibited the highest overall system efficiencies.

Figure 1-4: 2014 Overall and Component Efficiencies by Technology, LHV Basis*



FC-CHP = Fuel Cell-Combined Heat and Power; FC-Elec = Fuel Cell-All Electric; GT = Gas Turbine, ICE = Internal Combustion Engine, MT = Microturbine, PRT = Pressure Reduction Turbine, WD = Wind Turbine

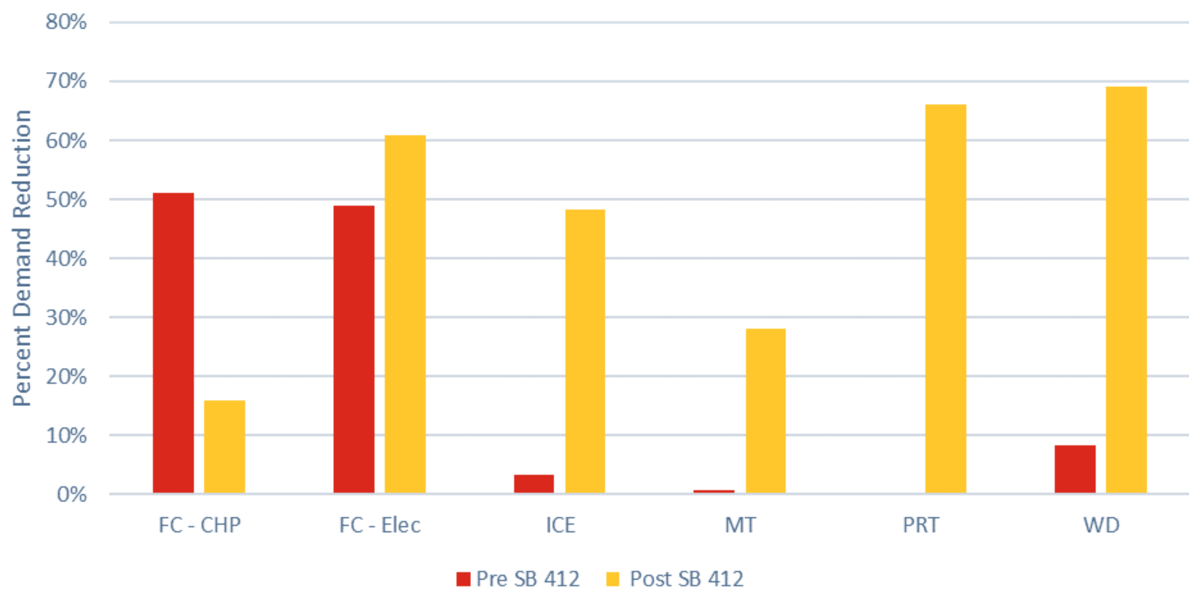
*Dotted line refers to required minimum 60% overall system efficiency (HHV), 54.2% LHV for all technologies except all-electric fuel cells. A separate dotted line is shown for all-electric fuel cells at a 40% minimum electric efficiency.

In accordance with requirements in SB 861,[8] we also examined the impact of SGIP on aggregate noncoincident peak customer demand. Customer peak demand may not occur at the same time as the utility or CAISO peak demand. Consequently, examining the aggregate noncoincident peak customer demand provides a way to identify the extent of the impact SGIP projects have on customer demand.

Figure 1-5 shows the amount of customer demand reduction (MW reduction per MW of generating capacity) for 2015, broken down by non-AES technology. We have also further broken down the customer demand reduction by pre- and post-SB 412 categories. In general, there is a marked increase in customer demand reductions between pre- and post-SB 412 categories, except for Combined Heat and Power Fuel Cells, which saw a decrease in customer demand reductions between pre- and post-SB 412 categories. This is due to two of the four post-SB 412 Combined Heat and Power Fuel Cells being offline during the customers' peak load in 2015. In addition, most of the post-SB 412 technologies provide at least a 40% reduction in customer demand (relative to the rebated generating capacity) but can achieve (i.e., in the case of all-electric fuel cells) as much as 60% reduction.

8 Senate Bill 861, Public resources trailer bill, June 20, 2014. We specifically used the definition of aggregate noncoincident peak as defined by the CPUC ruling in Decision 12-05-036 (May 12, 2014) on calculating the net metering cap. http://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/167591.pdf

Figure 1-5: Customer Demand Reduction per Generating Capacity (MW/MW) by Technology - 2015



FC-CHP = Fuel Cell-Combined Heat and Power; FC-Elec = Fuel Cell-All Electric; GT = Gas Turbine, ICE = Internal Combustion Engine, MT = Microturbine, PRT = Pressure Reduction Turbine, WD = Wind Turbine

Section 5 (Non-AES Energy Impacts) contains additional and detailed information on the energy impacts associated with non-AES projects.

Advanced Energy Storage (AES) Energy and Demand Impacts for 2014-2015

AES technologies are nascent and still emerging into the marketplace. This impact evaluation represents the first SGIP impact evaluation that had sufficient metered data to go beyond case studies. However, we experienced problems in obtaining data for this evaluation and in particular, matched customer demand and AES charge/discharge data. In spite of the data issues, we were able to examine impacts in different ways.

Our non-residential sample size is 115 projects. This sample represents 21 (72%) of the 29 non-residential performance-based incentive (PBI) projects[9] operating in 2015, plus 94 (64%) of the 146 non-residential, non-PBI SGIP projects operating in 2015. Data for the non-PBI projects represent 64% of all non-residential, non-PBI projects operating under the SGIP program in 2015. Our sample features 4 systems (3 PBI and 1 non-PBI) paired with PV.

Of the 21 non-residential PBI SGIP projects in our 2015 sample, we were able to match load data to 12 projects. These 12 projects came online at varying months during 2015, and only two have a full year of

[9] PBI projects are defined as those with a rated capacity of 30 kW or higher. *2016 Self-Generation Incentive Program Handbook,* 2016, available at https://www.selfgenca.com/home/resources/.

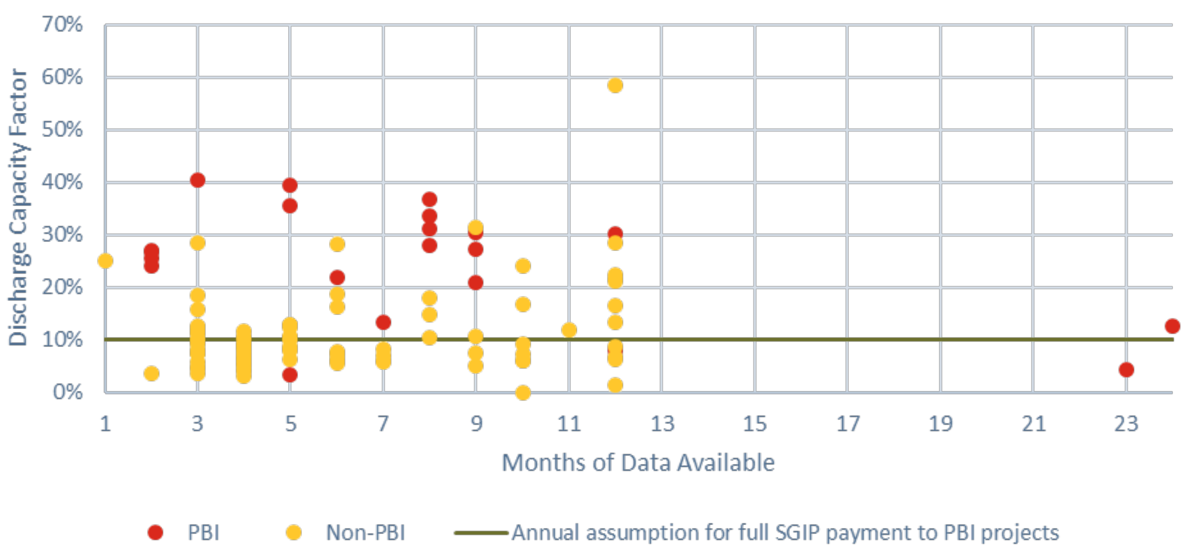
data. We were unable to match non-PBI, non-residential projects with load data because the storage providers for these projects anonymized their data. We therefore used different approaches to examine AES performance taking into account the lack of matching demand and charge/discharge data.

The residential data used for this AES evaluation were limited to storage charge and discharge (kW or kWh), as well as solar generation (kW or kWh) data for 34 projects. This data represents roughly 20% of the residential AES projects operating under SGIP in 2015.

We examined AES ability to achieve a set capacity factor in light of AES discharge requirements outlined in the SGIP handbook. In particular, the expectation is that AES projects subject to PBI rules will discharge for the equivalent of a 10% capacity factor over 5,200 hours, or 520 hours over the course of each year in order maximize PBI payments.[10] Note that while PBI systems are tied to that assumption, non-PBI projects are not required to meet the 10% capacity factor. Nonetheless, this metric provides a common and reasonable yardstick to gauging one facet of AES performance.

As shown in Figure 1-6, the range of 2015 capacity factors across non-residential storage projects varies widely. Specifically, 18 of the 21 (86%) PBI projects and 40 of the 94 (43%) non-PBI projects displayed discharge capacity factors of at least 10%.

Figure 1-6: Storage SGIP Capacity Factors as a Function of Months of Data Available for Each Storage Project, 2015

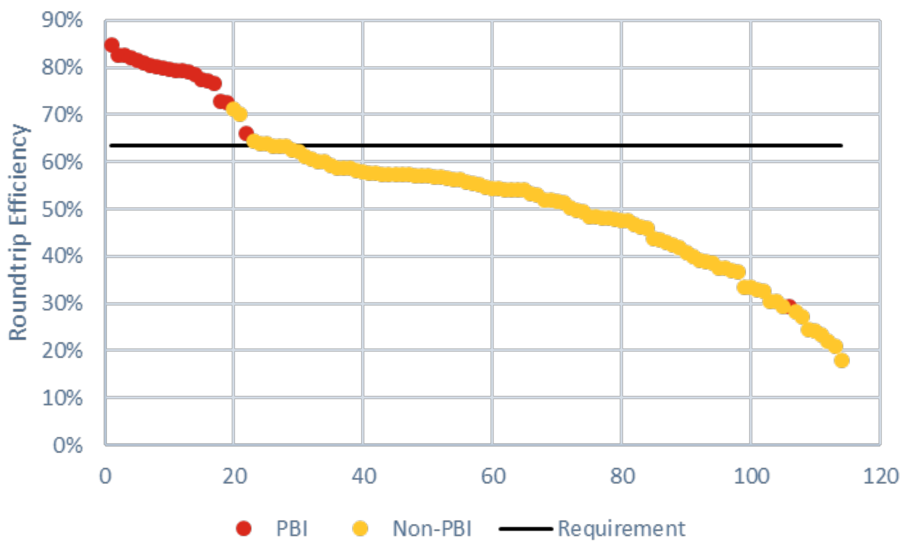


We also examined AES performance using AC roundtrip efficiency (RTE), defined as the percentage of energy maintained in a roundtrip through the battery (or 100% - Loss Rate). To meet the SGIP's 2014 and 2015 GHG Standard requirement each storage project is required to have a RTE of at least 63.5% on an

10 "520 discharge hours" refers to the amount energy released when discharging a battery at full capacity for 520 hours. AES Projects typically discharge during peak weekday periods and are unable to discharge during their charging period. For this reason, 5,200 hours per year will be used for the purposes of calculating the capacity factor for AES projects. That is, a system may discharge at full capacity for 520 hours, or, say, 50% capacity for 1,040 hours – the amount of energy in the two is the same, each constituting 520 discharge hours.

annual basis.[11] Figure 1-7 shows the RTE for the AES projects based on available metered data.[12] Only 25 of the 115 observed non-residential projects (22%) operating in 2014 or 2015 satisfied the 63.5% RTE requirement. Over 95% of the PBI projects (20/21) met the 63.5% RTE requirement, whereas only 5% of the non-residential non-PBI projects (5/94) met the 63.5% RTE requirement. RTE is important not only as a measure of the efficiency with which AES systems operate but also in the impact on GHG emissions (a higher RTE may lead to lower GHG emissions, depending on when systems are charged and discharged). We observed a statistically significant correlation between utilization, capacity factor and RTE. AES projects that were utilized more, with higher capacity factors exhibit higher RTE. That has implications not just for utilization but also emissions impact since higher RTE is one component of reducing emissions with AES.

Figure 1-7: Roundtrip Efficiency for Observed Projects (all non-residential)



Another important performance metric is how customers used AES projects in meeting their energy needs. In general, customers can use AES systems for time-of-use (TOU) energy rate arbitrage or to help minimize demand charges.

Figure 1-8 presents the results of the summer discharge energy that took place over each of the three TOU periods for AES PBI projects.

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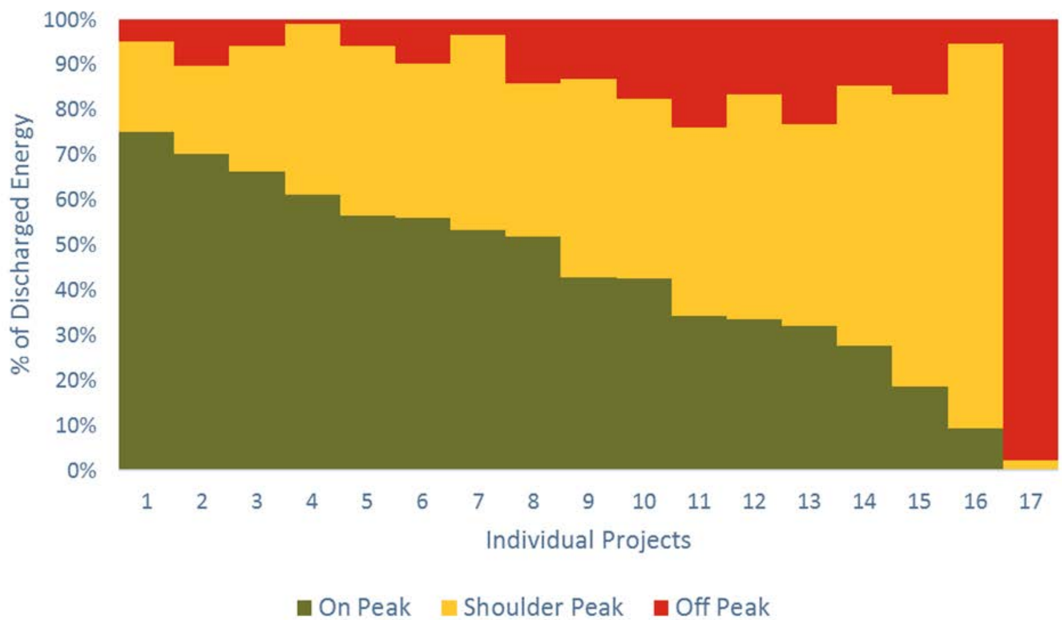
11 See 2015 SGIP Handbook, p. 52.

12 Because RTE is more a measure of the physical capabilities of a project rather than anything time-dependent, we combined 2014 and 2015 data into one statistic for the two PBI projects that operated during 2014.

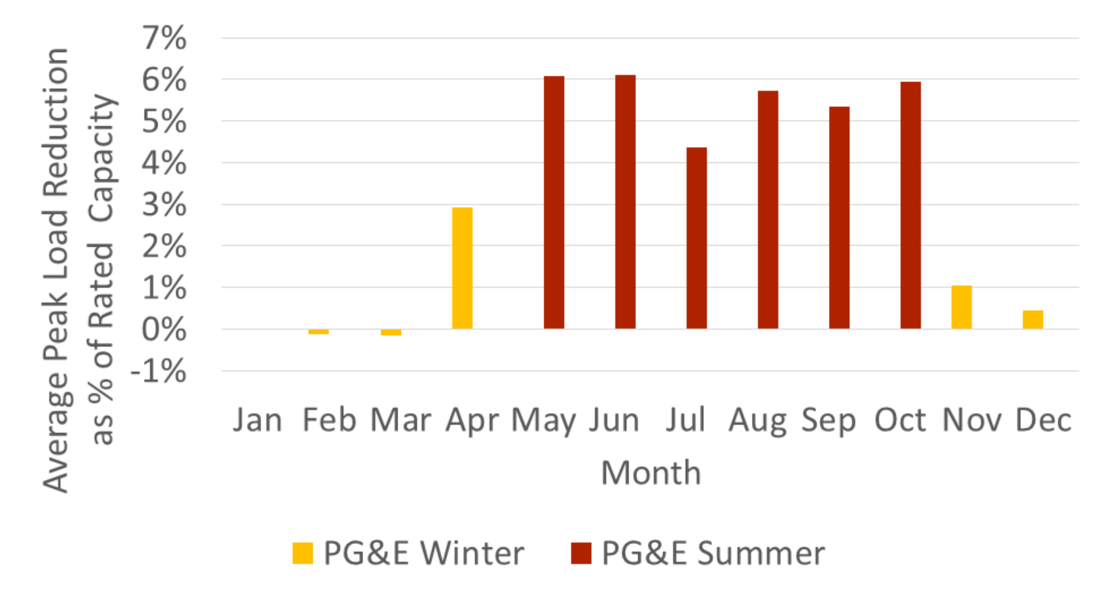
Figure 1-8: PBI Project Discharge by Assumed TOU Period (Sorted by On-Peak Percent), 2014 - 2015



TOU rate arbitrage did not appear to be a high priority for those dispatching non-residential storage projects in 2015. No PBI project discharged more than 75% of their total energy during on-peak TOU periods, and only 8 of the 17 PBI projects with summer dispatch discharged 50% or more of their energy on peak. One PBI project discharged virtually exclusively *off-peak*. We also examined non-PBI, non-residential projects and found that on-peak discharge was even lower for these projects. Only five of the non-PBI projects had 35% or more of their discharged energy on peak during 2015, and 18 projects (16%) discharged 70% or more of their energy *off-peak.* Consequently, while these results show that dispatch of some storage projects was aligned with TOU periods in the 2014 – 2015 period, TOU energy rates are likely not the main driver of this behavior. Due to poor data quality, we were not able to evaluate TOU rate arbitrage behavior with confidence for residential storage projects.

To explore whether storage projects were dispatched to minimize demand charges, we analyzed peak demand (kW) and demand charges ($) with and without storage for a sample of five projects. Figure 1-9 shows the average peak demand reduction by month for the examined projects.

Figure 1-9: Average Peak Demand Reduction by Month (% of rebated storage capacity), PBI Projects, 2015

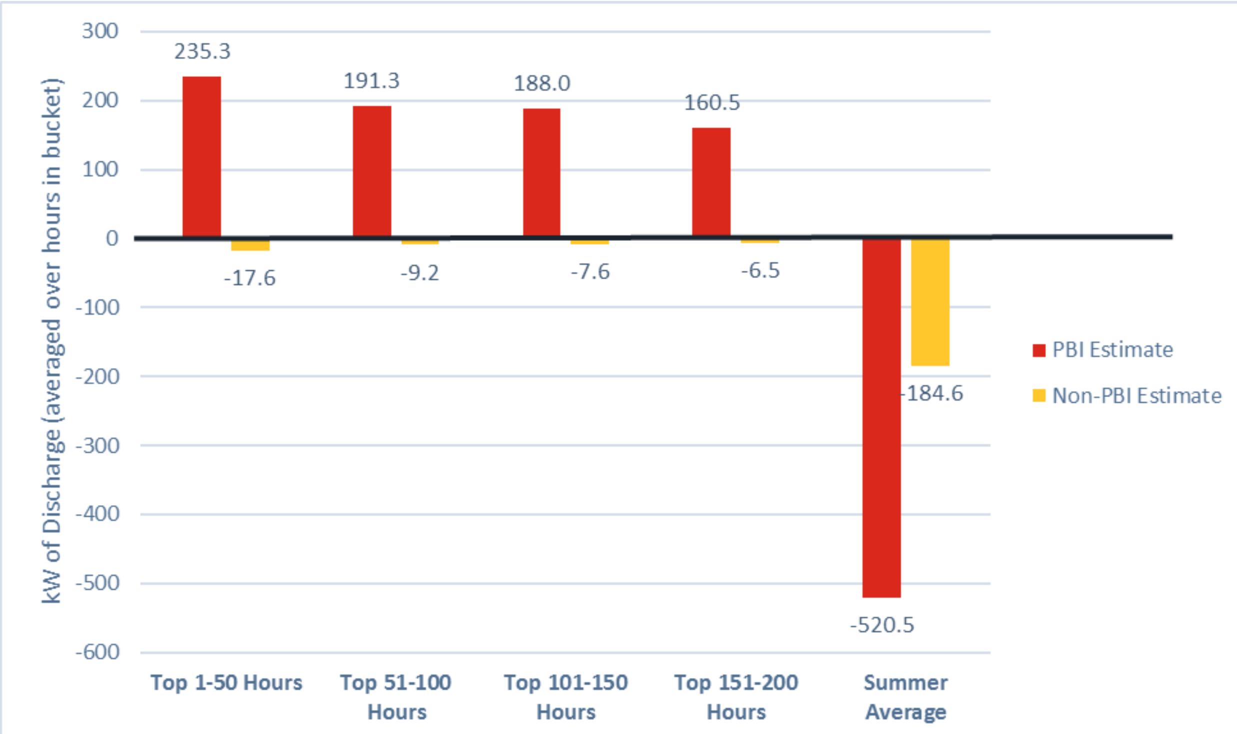


For the five projects with summer load and dispatch data, the average annual demand reduction was 0.8 kW. This metric ranged from a 37.3 kW *increase* in peak demand for a 1,000 kW storage project subject to high on-peak demand charges to a 25.3 kW *reduction* in peak demand for a 200 kW project with only monthly facility-related, non-TOU demand charges. We found the average monthly maximum demand reduction across all sampled projects with demand charges to be 0.06 kW per kW rebated storage capacity.

One important opportunity for storage projects to create value for the electricity grid lies in their ability to shift load from peak system hours to hours when demand is lower. Discharging storage during peak system hours creates value by reducing peak system demand, thereby avoiding generation capacity and/or transmission and distribution capacity costs.

We sought to determine the effect of SGIP storage projects on system demand during system peak hours. To measure this effect, we determined the net aggregate discharge from the storage projects in the peak 200 hours of the year (2014 or 2015) and compared this to the net average discharge over all summer hours, defined as June through October, inclusive. That is, we measured whether there was significantly more storage discharging in peak hours compared to the summer average. Figure 1-10 shows the average net discharge for all non-residential customers (both PBI and non-PBI) over the top 200 hours for 2015.

Figure 1-10: Estimate of Population-Level System Peak Impacts Compared to Summer Average, Non-Residential Storage Projects, 2015



Overall, both PBI and non-PBI non-residential storage projects show much lower power consumption in all of the top 200 system hours than they do on average during the summer. That is, non-residential storage customers are, on average, at least somewhat avoiding charging during peak hours. However, while the PBI projects show a net discharge during peak hours - reducing demand and benefiting the grid - the non-PBI customers are, in aggregate, charging during the top 200 hours. This implies that the motivations to avoid charging during peak hours are insufficient, and that there is a significant opportunity to make better use of these projects from a grid-level perspective

Given the increasing importance of favorable storage dispatch timing, temporal incentives including rate design will become increasingly critical. Rate design will remain a key incentive mechanism as long as storage project dispatch is compensated at retail rates. To minimize emissions from SGIP customers, rate designs should encourage charging during time periods with low marginal costs and emissions and encourage discharging during higher-cost, higher-emission hours.

Two key focus areas for achieving more optimal storage dispatch are 1) improving rate design incentives and 2) making sure the party responsible for dispatch receives the appropriate signals. Potential beneficial rate design adjustments include aligning time-of-use periods with marginal costs and emissions, applying on-peak demand charges, applying demand charges that vary geographically and reflect distribution peak hours, and instituting dynamic rates that offer more granular price signals and vary with system conditions.

Regarding our analysis of the impact of SGIP AES projects on greenhouse gas emissions, we found that our sample of PBI projects charged during periods of low marginal grid CO_2 emissions and discharged during periods of higher marginal emissions in 2015. However, roundtrip efficiency losses resulted in a net emissions increase of 13 metric tons across the 21 observed PBI projects. For non-PBI projects, we see a larger increase. This is due to a combination of lower roundtrip efficiencies and worse timing of storage dispatch. In all, the non-PBI projects show about 19 additional tons of CO_2 emissions. Scaling up these samples to program-wide levels, we estimate CO_2 emissions increases for the PBI and non-PBI projects to be 21 and 39 tons, respectively.

In addition to the potential methods for improving the GHG profile of storage dispatch referred to above, we note that the CPUC is taking steps to improve the GHG profile of storage systems. CPUC Decision (D.) 16-06-055 made adjustments to the operational requirements for storage systems that may assist their GHG emissions profile. For example, the Decision prioritized SGIP storage applications for projects that are paired with a renewable generator and that demonstrate they are charged from renewable energy.

Additionally, significant reforms to the peak periods for energy charges are being considered in several active proceedings. In PG&E's General Rate Case Phase II (A.16-06-013), PG&E is seeking to shift peak hours for commercial customers from 12-6pm to 5-10pm. If this proposal is accepted, this may improve incentives for storage charge and discharge at times that optimize GHG reductions.

Section 6 (AES Energy Impacts) contains additional and detailed information on AES energy impacts.

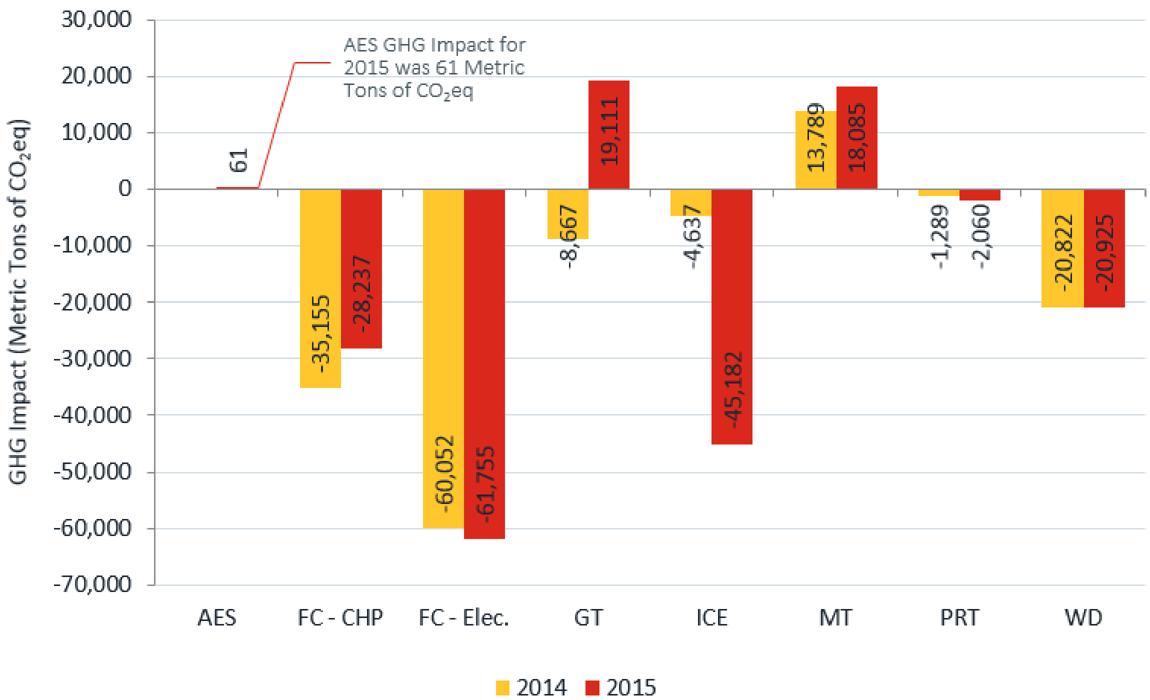
SGIP Environmental Impacts for 2014-2015

Overall, the SGIP reduced GHG emissions by 116,835 tons[13] in 2014 and by 120,903 tons in 2015. Figure 1-11 shows the breakdown of GHG impacts by technology type and calendar year. Electric only fuel cells achieved the largest reductions in GHG emissions during 2014 and 2015, followed by internal combustion engines in 2015. Microturbines were the only technology type that increased greenhouse gas emissions during 2014 and 2015 relative to a conventional energy services baseline. Emissions from gas turbines increased and turned positive during 2015, whereas emissions from internal combustion engines significantly decreased in 2015. GHG emissions from AES projects represented a negligible increase.

We note that CPUC staff asked Itron to include a "build margin" analysis for calculating GHG emissions from SGIP projects, consistent with the methodology outlined in CPUC Decision (D.) 15-11-026. Please refer to section 7.5 of this report for more details on this methodology and its results. SGIP projects remain net reducers of GHG emissions using the build margin methodology.

[13] CO_2 Equivalent

Figure 1-11: Greenhouse Gas Impacts by Technology Type and Calendar Year

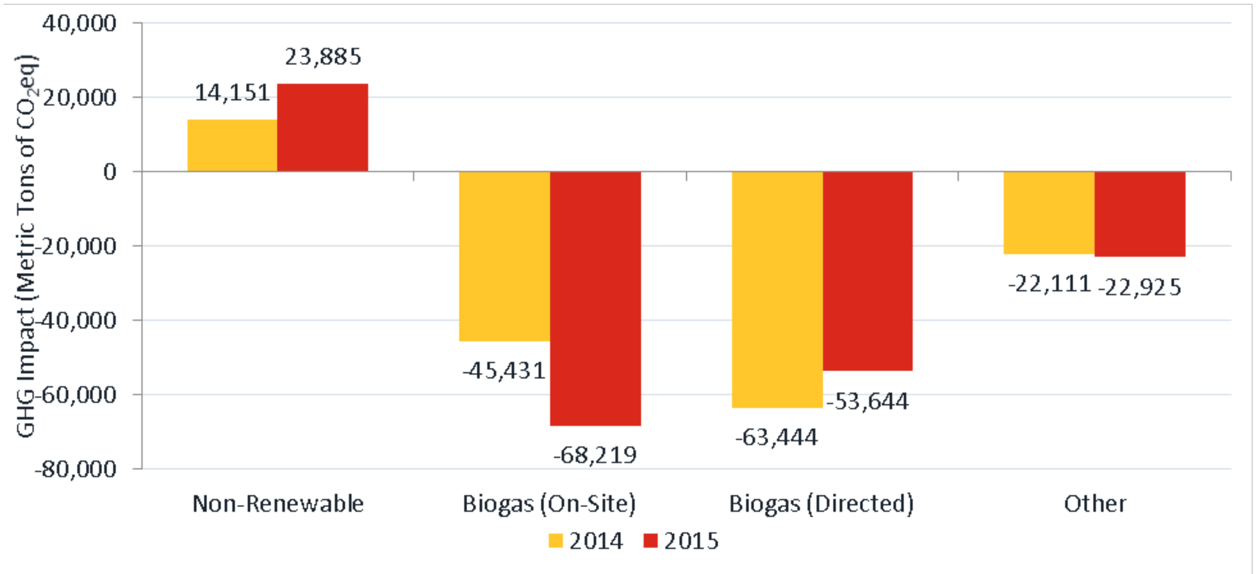


AES = Advanced Energy Storage; FC-CHP = Fuel Cell-Combined Heat and Power; FC-Elec = Fuel Cell-All Electric; GT = Gas Turbine, ICE = Internal Combustion Engine, MT = Microturbine, PRT = Pressure Reduction Turbine, WD = Wind Turbine

Fuel source can have a significant impact on GHG emissions. Renewable fuel sources result in GHG emission reductions. Figure 1-12 shows the contribution of renewable and non-renewable fuel sources on GHG impacts during 2014 and 2015. The "Other" category includes wind turbines and pressure reduction turbines.

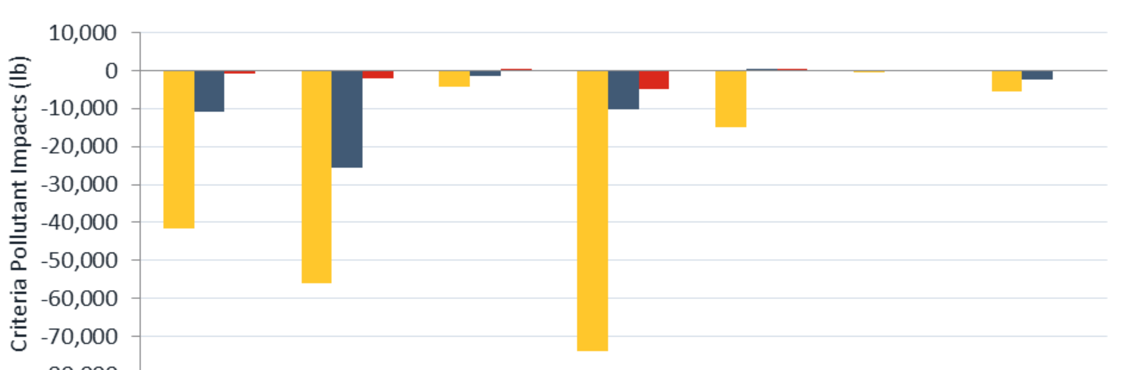
On average, non-renewable projects increased GHG emissions during 2014 and 2015. Projects fueled by all other energy sources achieved GHG emissions reductions. The majority of SGIP emissions reductions arise from on-site and directed biogas projects.

Figure 1-12: Greenhouse Gas Impacts by Energy Source and Calendar Year[14]



SGIP also has the ability to reduce criteria air pollutants; largely through displacement of grid emissions by renewable energy sources such as wind energy projects, very clean generation such as fuel cells or by displacement of boiler fuel by CHP projects. Figure 1-13 shows a summary of criteria air pollutant impacts for 2015 by technology.

Figure 1-13: Criteria Pollutant Impacts by Technology Type (2015)



	FC - CHP	FC - Elec.	GT	ICE	MT	PRT	WD
NOx	(41,623)	(56,120)	(4,382)	(74,012)	(14,954)	(546)	(5,386)
PM10	(10,832)	(25,552)	(1,492)	(10,109)	157	(245)	(2,404)
SO2	(827)	(1,992)	196	(4,762)	200	(19)	(195)

FC-CHP = Fuel Cell-Combined Heat and Power; FC-Elec = Fuel Cell-All Electric; GT = Gas Turbine, ICE = Internal Combustion Engine, MT = Microturbine, PRT = Pressure Reduction Turbine, WD = Wind Turbine

14 The energy source 'Other' includes wind turbines and pressure reduction turbines (excludes AES).

During 2015, SGIP projects decreased NO_X and PM_{10} emissions by 197,023 pounds and 50,477 pounds respectively. During the same period SO_2 emissions decreased by 7,400 pounds relative to the absence of the program.

Section 7 contains additional and detailed information on the environmental impacts associated with SGIP projects.

Program Level Comparisons

We compared impact results on a program level basis to identify possible sources of concerns with program results and determine possible corrective actions.

In looking at pre-SB 412 project impact versus post-SB 412 project impacts, we found there were distinct and significant differences in the impacts. It is apparent that pre-SB 412 projects provide a distinctly different set of impact results from the post-SB 412 projects; and these tend to be tied to the older age of the pre-SB 412 projects or different program requirements. Consequently, as the SGIP moves forward with new projects, retaining pre-SB 412 projects that embed older, non-representative projects could skew the evaluation results unfavorably.

In assessing AES and non-AES project impacts, we determined (based on the available data and how AES is currently operated) that non-AES projects are generally providing better levels of GHG emission reductions, and better system peak and customer peak demand relief than their AES counterparts. We do not believe this is due to the inherent nature of AES but instead this difference points to the fact that AES projects are not currently operated in ways that address the SGIP key objectives of reducing GHG emissions and achieving peak demand relief.

We were asked to examine the impact of the RPS build margin on SGIP’s GHG emissions. In doing so, we found that if older SGIP projects had been subject to the RPS build margin requirements, it would have had the effect of eliminating a significant portion of the historical net GHG emissions reductions attributed to the SGIP. However, the RPS build margin is applied only to the projects after their fifth year of operation. As a result, the GHG emissions impact is more pronounced for technologies that have been in the SGIP for longer periods of time. Moving forward, if the SGIP is evaluated using only post-SB 412 projects to ensure an “apples to apples” comparison of technologies with similar ages, this essentially eliminates use of the build margin approach for post-SB 412 projects until 2017-2018. In addition, we conducted a preliminary analysis of GHG emissions based on pre-SB 412 versus post-SB 412 projects. The results indicate that under an evaluation that included only post-SB 412 projects, the SGIP would still likely have a significant amount of net GHG emission reductions.

Section 8 contains additional and detailed information on these program level comparisons.

1.2 Conclusions and Recommendations

Based on the available data and the information presented in this study, we make the following conclusions:

1. **The SGIP continues to reduce GHG emissions.** In both 2014 and 2015, the SGIP reduced GHG emissions by over 110,000 tons per year; equivalent to reducing GHG emissions from over 20,300

passenger vehicles.[15] It also represents a nine-fold reduction in GHG emissions from the SGIP 2007 levels.

a. **Currently, non-AES projects provide all of the SGIP's GHG emission reductions**. As shown in the program level comparisons, renewable fueled, non-AES projects are currently providing the vast majority of the GHG emission reductions for the SGIP. AES projects (as currently configured and operated) are resulting in <u>small increases</u> in GHG emissions. In particular, renewable fueled, non-AES projects provide are reducing GHG emissions at a rate from 5 times to nearly 70 times the GHG emission *increase* impact rate of AES projects (on a ton of CO_2 per MWh basis). Because AES projects tend to accrue net GHG emission reductions by discharge during peak demand hours and there is limited energy discharged during this time, this means there would have to be a substantial increase in effective AES discharge to obtain the equivalent net GHG emission reductions provided by renewable fueled, non-AES projects.

2. **The SGIP continues to provide peak demand and energy reductions.** SGIP projects generated over 1 Terawatt Hour (TWh) of electricity annually in both 2014 and 2015, representing approximately 0.5 percent of California's total in-state generation. SGIP also helped to reduce CAISO peak demand to California's electricity customers in 2014 and 2015 by approximately 145 MW and 162 MW, respectively.

3. **The SGIP provides reductions in aggregate noncoincident customer peak demand.** In 2015, the SGIP provided on average a 40% reduction in aggregate noncoincident customer peak demand relative to the rebated generating capacity of the SGIP project. That is, an SGIP project with a rebated generating capacity of 1 MW would on average provide an aggregate noncoincident customer peak demand reduction of 400 kW.

   a. **Non-AES projects provide the majority of the reductions in aggregate noncoincident customer peak demand.** While non-AES projects show an overall average reduction of 40% of rebated generating capacity, AES projects showed an aggregate noncoincident customer peak demand reduction of only 6% of rebated capacity.

4. **The SGIP continues to reduce emissions of criteria air pollutants.** During 2014 and 2015 combined, SGIP projects decreased NO_X and PM_{10} emissions by 370,003 pounds and 97,341 pounds respectively. During 2015 alone, SGIP projects decreased NO_X and PM_{10} emissions by 197,023 pounds and 50,477 pounds respectively. During the same period SO_2 emissions decreased by 7,400 pounds relative to the absence of the program.

5. **The SGIP leverages ratepayer funds.** As of the end of 2015, the SGIP had provided $656 million in incentives to projects with an estimated total cost of $2.3 billion; representing a leverage ratio of greater than 3.5 to one.

6. **AES project performance is indicative of a nascent technology.** In general, we found that the vast majority of AES projects we evaluated met the SGIP discharge requirements. Conversely, we found that only 22% of the evaluated AES projects satisfied the 63.5% RTE requirement. Although we were limited by not having load data, our evaluation of discharge patterns for AES projects tended to show that PBI customers are dispatching their storage very differently than non-PBI non-residential

[15] http://www.epa.gov/cleanenergy/energy-resources/refs.html

customers. These differences lead to questions about how customers are using their AES projects and the degree to which that coincides with utility or other ratepayer needs. Our assessment of the impacts of AES system operation on peak demand indicates that while the PBI projects show a net discharge during peak hours - reducing demand and benefiting the grid - the non-PBI customers are, in aggregate, charging during the top 200 hours. This suggests that the motivations to avoid charging during peak hours may be insufficient, and that there is a significant opportunity to make better use of these projects from a grid-level perspective. Lastly, we note that we could not assess potential benefits from future grid integration of renewables combined with AES due to the lack of data but that future impact evaluations should investigate this issue if the data is available.

7. **Pre-SB 412 projects may be misinforming program evaluations.** As shown from the results presented in this evaluation, pre-SB 412 projects tend to "under-perform" relative to their post-SB 412 counterparts. In general, pre-SB 412 projects show lower GHG emission reduction impacts, lower average annual capacity factors, and lower aggregate noncoincident customer peak demand reductions. As pre-SB 412 projects tend to be significantly older than post-SB 412 projects, these results can be expected due to more frequent and longer outages. However, as the SGIP moves forward and newer projects come on line, retaining pre-SB 412 projects in the evaluation could lead to comparisons that embed older, non-representative projects thereby skewing the evaluation results.

8. **SGIP lacks critical evaluation information.** Data on customer demand and data on AES system charge and discharge that could be matched to customer demand were largely missing from this evaluation. Attempts to obtain the data through Non-Disclosure Agreements required lengthy reviews by all parties and in the end did not provide the needed information due to requirements that the data be anonymized; which prevented matching of customer demand data to AES charge and discharge data. However, matching of customer demand data to AES and non-AES project operations (i.e., charge/discharge or generation) is essential to accurately determining at the program level, the performance and impacts of the SGIP on customers. Moreover, this information is necessary for the SGIP to be responsive to the legislative requirements in SB 861 that the CPUC examine and evaluate the successfulness of the SGIP in reducing GHG emissions and reducing aggregate noncoincident customer peak demand.

Based on these conclusions, we present the following recommendations:

1. **Require customer load data be supplied to the SGIP evaluation team**: Interval (i.e., at minimum hourly) customer load data which can be matched to AES charge/discharge and non-AES generation data must be provided to SGIP evaluators in order to accurately estimate AES performance and aggregate noncoincident customer peak demand impacts. Approaches using nondisclosure agreements between evaluators, system suppliers, and IOUs fail to resolve the issue as suppliers of data often require the data sets be anonymized, which effectively precludes the ability to match load and storage/generation data. We strongly recommend that the CPUC require AES system suppliers and the IOUs to supply customer load and storage/generation data that can be matched. The CPUC currently requires IOUs to provide customer load data to evaluators for energy efficiency impact evaluations and similar approaches such be used to obtain the necessary customer load data for future SGIP impact evaluations.

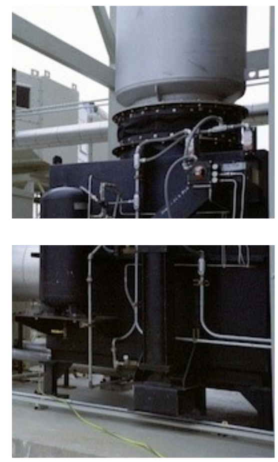
2. **Exclude pre-SB 412 projects in future SGIP impact evaluations**. The SGIP is unique in that it has a legacy of older projects still operating. However, these older projects not only show increased downtime, which affects program level impacts negatively, but were rebated under a different set of requirements than newer projects subject to SB 412. As a result, impact evaluations that embed older, non-representative pre-SB 412 projects can provide skewed impact evaluation results. We recommend that pre-SB 412 projects be excluded in future SGIP impact evaluations to allow more accurate assessment of the program's impacts and allow an "apples to apples" comparison among projects rebated under the SGIP.

3. **Modify the SGIP handbook to optimize AES operations going forward**. AES projects constitute an important and growing component of the SGIP. However, as evidenced by this impact evaluation, critical data is missing which is needed to provide policy makers with a thorough assessment of the performance and impacts associated with AES projects. Nonetheless, based on the available data, we observe that AES projects are not currently operating in ways to help the SGIP achieve its primary objectives of reducing GHG emissions, and helping to relieve utility and customer peak demand. We've noted above that two key steps to achieving more optimal storage dispatch are 1) improving rate design incentives and 2) making sure the party responsible for dispatch receives the appropriate signals. Potential beneficial rate design adjustments include aligning time-of-use periods with marginal costs and emissions, applying on-peak demand charges, applying demand charges that vary geographically and reflect distribution peak hours, and instituting dynamic rates that offer more granular price signals and vary with system conditions. Effecting those changes requires policy decisions that are larger than the SGIP and may likely be decided through proceeding that will take some time. However, at minimum, the SGIP Handbook should be modified to better fit AES operations to the goals and objectives of the SGIP. For example, the AES discharge requirement of discharging based on a 10% annual capacity factor and 5,200 hours per year does not address use of AES to help provide system or customer peak demand relief. Adjusting the handbook to more appropriately and explicitly focus AES to discharge in ways to provide system and customer peak demand relief is necessary. In addition, discharge that is geared to providing peak demand relief is also likely to help reduce net GHG emissions. Developing these changes will likely require further research.

Additional information on program background, status, and impacts is provided in Sections 2 through 8. The report's five appendices describe in detail the sources of data and methodologies used to quantify impacts.

Introduction and Objectives

2



2 INTRODUCTION AND OBJECTIVES

Established legislatively in 2001[1] to help address peak electricity problems facing California, the Self-Generation Incentive Program (SGIP) represents one of the longest-lived and broadest-based distributed energy resources (DER) incentive programs in the country.

The SGIP is funded by California electricity rate payers and managed by Program Administrators (PAs) representing California's major investor owned utilities (IOUs).[2] The CPUC provides oversight and guidance on the SGIP.

Since its inception, the SGIP has provided incentives to a wide variety of distributed energy technologies including gas turbines, internal combustion (IC) engines, fuel cells and microturbines;[3] solar photovoltaic (PV) and wind turbine systems; and advanced energy storage (AES) systems. Section 3 provides additional discussion about changes in technology eligibility within SGIP over time.

Table 2-1 is a listing of technologies eligible to receive SGIP incentives during program years 2014 and 2015.

Table 2-1: SGIP Eligible Technologies During 2014-2015

Category	Technology Type
Renewable and Waste Energy Recovery	Wind Turbine
	Waste Heat to Power
	Pressure Reduction Turbine
Non-renewable Conventional Combined Heat and Power (CHP)	Internal Combustion Engine – CHP
	Microturbine – CHP
	Gas Turbine – CHP
Emerging Technologies	Advanced Energy Storage
	Biogas Adder[4]
	Fuel Cell – CHP or Electric Only

[1] During the summer and fall of 2000, California experienced a number of rolling blackouts that left thousands of electricity customers in Northern California without power and shut down hundreds of businesses. In response, the California legislature passed AB 970 (California Energy Security and Reliability Act of 2000) (Ducheny, September 6, 2000). http://www.leginfo.ca.gov/pub/99-00/bill/asm/ab_0951-1000/ab_970_bill_20000907_chaptered.html. The SGIP was established the following year as one of a number of programs to help address peak electricity problems.

[2] The Program Administrators are Pacific Gas & Electric (PG&E), Southern California Edison (SCE), Southern California Gas Company (SCG), and the Center for Sustainable Energy (CSE), which implements the program for customers of San Diego Gas & Electric (SDG&E).

[3] These distributed generation technologies can be fossil-fueled and biogas-fueled.

[4] The biogas adder is an incentive that may be used in conjunction with fuel cells or any conventional CHP technology.

2.1 Purpose and Scope of Report

The original CPUC Decision (D.) 01-03-073 establishing the SGIP required "program evaluations and load impact studies to verify energy production and system peak demand reductions" resulting from the SGIP.[5] That March 2001 decision also directed the assigned the Administrative Law Judge (ALJ), in consultation with the CPUC Energy Division (ED) and the PAs, to establish a schedule for filing the required evaluation reports. Since 2001, thirteen annual SGIP impact evaluations have been conducted.[6]

The SGIP has evolved to meet the changing energy and policy needs of California. Annual SGIP impact evaluation reports have in turn have reflected changes in SGIP eligibility criteria and success metrics. The primary purpose of this report is to quantify the energy, demand, and environmental impacts of the SGIP during calendar years 2014 and 2015. Impacts are reported for the SGIP as a whole and by other categories such as technology type, fuel type, PA, and electric utility. Some reported impacts are further categorized by program year to recognize the different program goals and rules in effect at the time of project development.

Specific objectives for this 2014-2015 evaluation include:

» Energy impacts including electricity generated, fuel consumed, and useful heat recovered. Efficiency and utilization metrics include annual capacity factor, electrical conversion efficiency, useful heat recovery rate, and system efficiency.

» Energy impacts are treated separately for advanced energy storage (AES) and include breakouts by charge and discharge impacts. We also assess round trip efficiency and discharge performance for AES in light of SGIP handbook requirements.

» Demand impacts (average reduction and capacity factor) during top demand hour and top 200 hours of the California Independent System Operator (CAISO) and California's three investor owned utilities. New to this impact evaluation, we also examine aggregate noncoincident customer peak demand impacts.

» Environmental impacts including those on GHG emissions and criteria air pollutants.

2.2 Scope

The scope of this impact evaluation is limited to the performance metrics discussed above. However, the SGIP includes a significant number of projects that were installed early on in the program and have continued to operate; providing benefits to both the host customer and the utility. As such, while the focus of this report is on impacts occurring during 2014 and 2015, these impacts result from a portfolio of projects that can span many years. Changes in program policies and requirements have created significant differences in operation and performance of the projects. In particular, Senate Bill 412[7] (Kehoe, October 11, 2009) established greenhouse gas (GHG) requirements that resulted in substantial changes in performance in CHP technologies installed under the SGIP following SB 412. Where appropriate, we

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5 CPUC Decision 01-03-073, March 27, 2001, page 37.

6 A listing of past SGIP impact reports can be found on the CPUC's website: http://www.cpuc.ca.gov/PUC/energy/DistGen/sgip/sgipreports.htm

7 http://www.leginfo.ca.gov/pub/09-10/bill/sen/sb_0401-0450/sb_412_bill_20091011_chaptered.pdf

differentiate impacts between pre-SB 412 projects and post-SB 412 projects. Similarly, due to the relatively new emergence of metered data on AES projects installed under the SGIP, difference in operation between generation technologies and storage technologies and the importance of AES within the program, we provide a separate section on AES energy impacts.

In addition, it is important to recognize that the impacts reported in this evaluation are based directly on metered performance data collected from a sample of SGIP projects. We use sampling methods and expand the results from the samples to the SGIP population using statistical approaches that conform to industry standards for impact evaluations. Sources of data and the estimation methodologies we use in treating the data are described in Section 4. Further explanation of the sources of data, our estimation methodologies and sources of uncertainties are contained in the appendices of the report.

2.3 Report Organization

This report is organized into seven sections and five appendices as described below:

» **Section 1** provides an executive summary of the key findings and recommendations from this evaluation.

» **Section 2** lays out the purpose, scope, and organization of the report.

» **Section 3** provides background and program status including project counts, rebated capacities, and incentive payment totals by technology type, energy source, and PA.

» **Section 4** summarizes the sources of data and statistical methods used to quantify impacts.

» **Section 5** presents energy and demand impacts for non-AES technologies including electricity generated, waste heat recovered, and fuel consumed. Trends in utilization and efficiency are also shown.

» **Section 6** presents energy, demand and environmental impacts for AES technologies.

» **Section 7** presents and discusses the GHG and criteria air pollutant impacts of all non-AES technologies.

» **Section 8** provides comparisons of impacts among different categories of projects including pre- versus post-SB 412 projects; AES project impacts versus non-AES project impacts; and GHG emissions with and without the RPS build margin taken into account.

» **Appendix A** provides supplementary program statistics not presented in Section 4.

» **Appendix B** describes in detail the methodology used to quantify energy and demand impacts and provides additional impacts not presented in Section 5.

» **Appendix C** describes in detail the methodology used to quantify greenhouse gas impacts and provides additional impacts not shown in Section 7.

» **Appendix D** describes in detail the methodology used to quantify criteria air pollutant impacts and provides additional impacts not shown in Section 7

» **Appendix E** describes the sources of uncertainty in impact estimates, the methodology used to quantify the uncertainty, and the results of the uncertainty analysis.

3

Background and Status

3 BACKGROUND AND STATUS

This section provides background on program policy and information on the status of the Self-Generation Incentive Program (SGIP) as of December 31, 2015. The status information is based on project data obtained from the Statewide Database provided by the Program Administrators (PAs). This section also summarizes active projects in the SGIP queue, which contains projects that may receive payments and become operational in future years. This report does not include impacts from photovoltaic (PV) projects that, prior to 2007, had been eligible to receive incentives under the SGIP.[1]

3.1 Program Background and Recent Changes Relevant to the Impacts Evaluation

In response to the electricity crisis of 2001, the California Legislature passed several bills to help reduce the state's electricity demand. In September 2000, Assembly Bill (AB) 970[2] (Ducheney, September 6, 2000) established the SGIP as a peak-load reduction program. In March 2001, the California Public Utilities Commission (CPUC) formally created the SGIP and received the first SGIP application in July 2001.

The SGIP was originally designed to reduce energy use and demand at host customer sites. The program included provisions to help ensure that projects met certain performance specifications. Minimum efficiencies were established, and manufacturer warranties were required. Originally, the SGIP did not establish targets for a total rebated capacity to be installed, reductions in energy use and demand, or contributions to greenhouse gas emissions reductions.

By 2007, growing concerns with potential air quality impacts prompted changes to the eligibility of technologies under the SGIP. In particular, approval of AB 2778[3] in September 2006 limited SGIP project eligibility to "ultra-clean and low emission distributed generation" technologies. Beginning January 1, 2007, only fuel cells and wind turbines were eligible under the SGIP. Passage of Senate Bill (SB) 412[4] (Kehoe, October 11, 2009) refocused the SGIP toward greenhouse gas (GHG) emission reductions and led to a re-examination of technology eligibility by the CPUC. As a result of that re-examination, the list of technologies eligible for the SGIP expanded to again include combined heat and power (CHP), pressure reduction turbines, and waste heat-to-power technologies. In addition, SB 412 required fossil fueled combustion technologies to be adequately maintained so that during operation they continue to meet or exceed the established efficiency and emissions standards. The passage of SB 412 marked a significant change in the composition of SGIP applications toward fuel cells and advanced energy storage projects.

In SB 412 a sunset date of January 1, 2016, was set for the SGIP. More recently, SB 861[5] authorized collections for the SGIP through 2019 and administration through 2020. The SGIP continues to be one of

[1] Effective January 1, 2007, PV technologies installed on the customer side of the meter were eligible to receive incentives under the California Solar Initiative (CSI). Impacts from PV installed under the SGIP are reported in the CSI impacts evaluation studies. Electronic versions of the CSI impacts studies are located at: http://www.cpuc.ca.gov/General.aspx?id=7623

[2] http://www.leginfo.ca.gov/pub/99-00/bill/asm/ab_0951-1000/ab_970_bill_20000907_chaptered.html

[3] http://www.leginfo.ca.gov/pub/05-06/bill/asm/ab_2751-2800/ab_2778_bill_20060929_chaptered.html

[4] http://www.leginfo.ca.gov/pub/09-10/bill/sen/sb_0401-0450/sb_412_bill_20091011_chaptered.pdf

[5] Public resources trailer bill, June 20, 2014. http://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201320140SB861

the largest and longest lived distributed energy resource (DER) incentive programs in the nation. The projects rebated by the SGIP since its inception reflect program objectives that have evolved over time.

Legislative Changes during 2014 and 2015

In addition to extending the SGIP through 2020, SB 861 made a number of structural changes to the program. The legislation restricted the eligibility of SGIP to distributed energy resource technologies that offset customer's onsite energy load, were found to be commercially available, safely utilized the grid, and improved air quality by reducing criteria air pollutants. SB 861 also required the CPUC to consider the relative amount and cost of greenhouse gas emission reductions, peak demand reductions, system reliability benefits, and other factors when allocating program funds among eligible technologies.

SB 861 also increased the amount of information to be made available regarding air emissions generated by SGIP projects. In particular, SB 861 required that SGIP projects provide relevant data to the Commission and the California Air Resources Board (ARB) upon request. In addition, SGIP projects were subject to onsite inspection to verify equipment operation and performance; including capacity, thermal energy output, and usage to verify criteria air pollutant and greenhouse gas emissions performance.

The legislation also requires that the Commission measure the SGIP's success and impacts based on the following performance measures:

- reductions of greenhouse gas emissions;
- reductions of criteria air pollutants as measured by avoided emissions and secured emission credits;
- energy reductions as measured in energy value;
- reductions of aggregate noncoincident customer peak demand;
- capacity factor of DER projects receiving incentives;
- avoided cost of transmission and distribution upgrades and replacement; and,
- onsite reliability.

CPUC Decisions

The administrative law judge (ALJ) Ruling on September 23, 2014 set forth the process for implementing the SGIP in accordance with the provisions of SB 861.[6] The ruling authorized the CPUC and PAs to implement the provisions specified in SB 861. On June 2, 2015, the ALJ ruling also merged the SGIP 2014 and 2015 impacts evaluation into a single report to be filed no later than September 30, 2016.[7]

One of the provisions of SB 861 required the CPUC to update the GHG emissions eligibility factor for the SGIP. The ALJ ruling on November 19, 2015 adopted a revised GHG emission factor for eligibility to the SGIP.[8] The GHG emission factor takes into account the most recent data available to the California Air Resources Board for GHG emissions from electricity sales as well as the estimated emissions of GHG over

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6 http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M108/K540/108540621.PDF

7 http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M151/K988/151988924.PDF

8 Decision 15-11-027; http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M156/K044/156044151.PDF

the useful life of the DER taking into account California's Renewable Portfolio Standard (RPS). Specific changes from the ALJ ruling include the following:

- The GHG emissions factor for eligible generation technologies was reduced from 379 kilograms of CO_2 per megawatt hour (kg/WMh) down to 350 kg/MWh.
- In light of increasing RPS procurement targets through 2030, the GHG emission factor for eligible technologies was further reduced to 337 kg/MWh for program year 2020.
- The minimum round trip efficiency for eligible AES technologies was revised from 63.5% to 66.5%.
- The ruling also identified the need to take into account the operating margin and build margin associated with RPS procurement targets.

3.2 Program Statistics in 2014-2015

Project Counts and Capacities to Date

Each SGIP project advances through a series of stages during its development. The scope of this impact evaluation is limited to 'completed' projects. Completed projects have been installed and begun operating, have passed their eligibility inspection, and were issued an incentive payment on or before December 31, 2015.[9,10,11] The SGIP has provided incentives to 1,144 completed projects representing over 440 MW of rebated capacity.

Table 3-1 shows counts and rebated capacities of completed projects for each Program Administrator. Pacific Gas & Electric (PG&E), Southern California Edison (SCE), and Southern California Gas Company (SCG) administer the SGIP within their electric and/or gas distribution service territories. The Center for Sustainable Energy (CSE) administers the program within San Diego Gas & Electric's (SDG&E's) service territory.

9 Some SGIP projects have been withdrawn/cancelled and are no longer under development. Others remain active and under development but are not yet complete. These active projects may be completed in the future.

10 Installation and final SGIP and local utility approval of SGIP projects occur over periods ranging from months to years. Limited operations (and thus small impacts) occur during this period, prior to incentive payment. However, operations (e.g., testing, commissioning) prior to incentive payment do not reflect long-run average performance. For purposes of this impacts evaluation, only completed SGIP projects are assumed to be accruing impacts.

11 Some projects receive a single incentive payment at the time of project completion. Others receive a portion of their total incentive at the time of project completion, and the remainder in annual payments following the first five years of operation. A detailed discussion of this distinction appears later in the section.

Table 3-1: Completed Project Count and Rebated Capacity by Program Administrator

Program Administrator	Project Count	Rebated Capacity (MW)	Percent of Rebated Capacity
CSE	127	44.8	10.2%
PG&E	612	188.9	42.9%
SCE	233	99.0	22.5%
SCG	172	107.4	24.4%
Total	***1,144***	***440.2***	***100%***

Table 3-2 shows project counts and rebated capacities by technology type. Internal combustion engines have been the predominant technology type in SGIP with 277 projects representing 178 MW of rebated capacity. The aggregate capacity of electric only and combined heat and power fuel cells ranks second in the program at 136 MW. Most recently, the program has seen dramatic growth in advanced energy storage (AES) projects. By December 31, 2015, the SGIP had issued incentives to 343 AES projects representing 21.3 MW of rebated capacity. Other technology types rebated by the SGIP include gas turbines, microturbines, pressure reduction turbines, and wind turbines.

Table 3-2: Completed Project Count and Rebated Capacity by Technology Type

Technology Type	Project Count	Average Rebated Capacity (kW)	Cumulative Rebated Capacity (MW)	Percent of Rebated Capacity
Advanced Energy Storage	343	62	21.3	4.8%
Fuel Cell – CHP	121	306	37.0	8.4%
Fuel Cell – Electric Only	215	458	98.5	22.4%
Gas Turbine	11	4,027	44.3	10.1%
Internal Combustion Engine	277	644	178.3	40.5%
Microturbine	150	210	31.4	7.1%
Pressure Reduction Turbine	2	525	1.1	0.2%
Wind Turbine	25	1,133	28.3	6.4%
Total	***1,144***	***385***	***440.2***	***100%***

The cumulative growth in SGIP capacity since its inception in 2001 is shown in Figure 3-1. There were 472 projects representing 110 MW of rebated capacity completed during 2014 and 2015.

Figure 3-1: Cumulative Rebated Capacity by Calendar Year

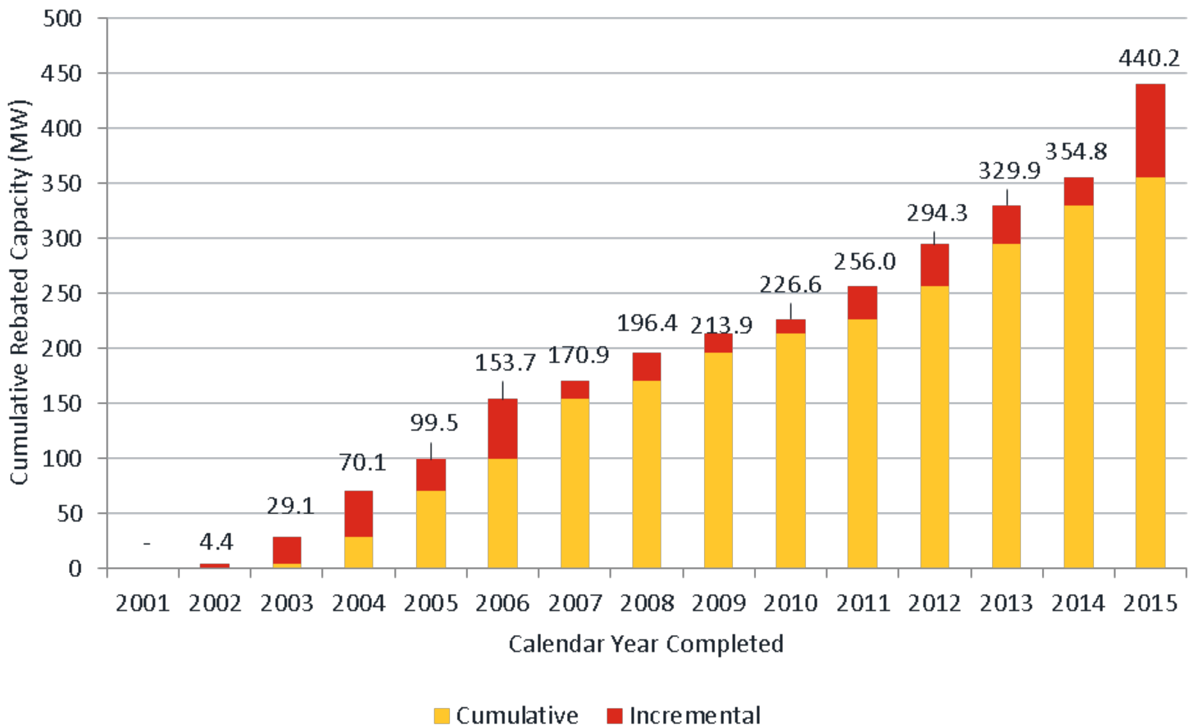
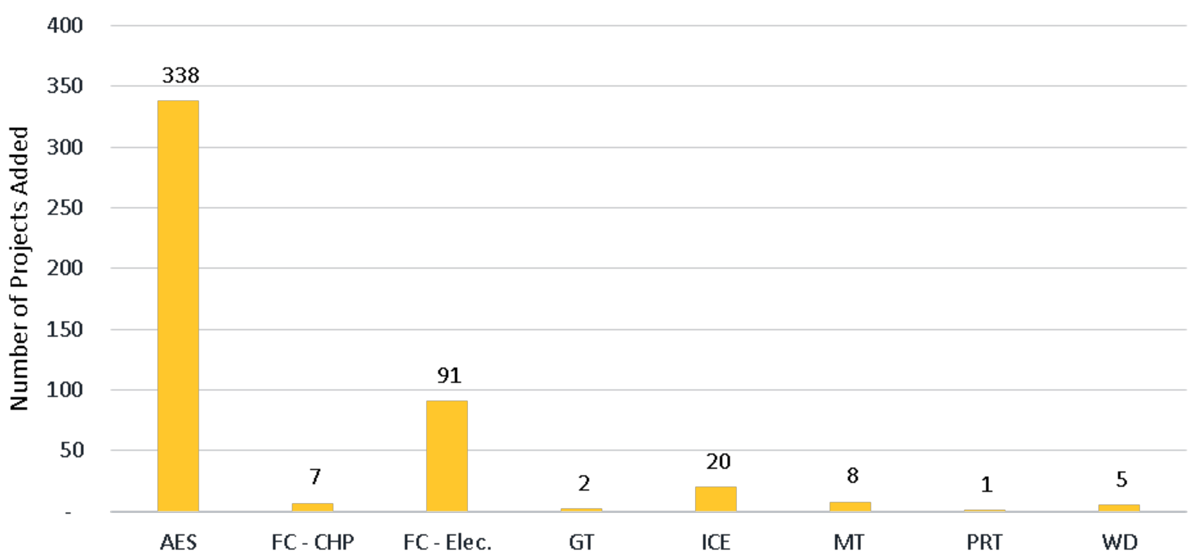


Figure 3-2 shows the breakdown of projects added during 2014 and 2015 by technology type. Of the 472 projects added during 2014 and 2015, the majority were AES projects, followed by electric only fuel cells.

Figure 3-2: Project Count Added During 2014 and 2015



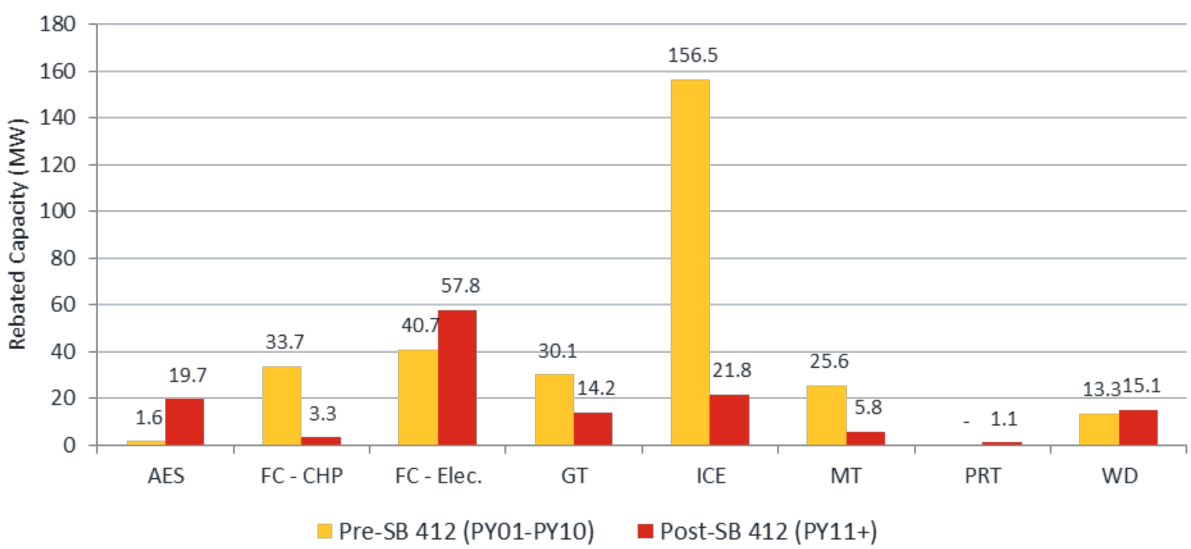
The date a project is completed is used to calculate its age, whereas the program year (PY) is the year in which the application for the project was received. Because program rules have evolved over time, a project's program year is used to determine what program rules and policies are applicable to it. For instance, PY12 projects are required to meet GHG emissions requirements, whereas PY02 projects are not.

One of the most important recent changes in the SGIP's design targeted its incentive structure. Completed projects from PY 2010 or earlier received their entire SGIP incentive at the time of project completion. This incentive structure is referred to as a 'capacity based" incentive. However, beginning in PY11 as a result of SB 412, new projects 30 kW and larger will receive half of their SGIP incentive at the time of completion and the remainder in annual payments following each of the first five years of operation. This incentive structure is known as a performance-based incentive (PBI).

To support assessment of possible differences in average performance of projects receiving capacity based incentives versus those receiving performance based incentives, each project was classified as either Pre-SB 412 or Post-SB 412 based on its program year. Completed projects that applied to the SGIP during PY01-PY10 are classified as Pre-SB 412. Completed projects that applied during or after PY11 (regardless of their incentive payment mechanism) are classified as Post-SB 412.

Figure 3-3 shows the rebated capacities of each technology type grouped by Pre/Post-SB 412 status. There are 521 projects representing 138.7 MW of rebated capacity completed Post-SB 412. The majority of the Post-SB 412 capacity comes from electric-only fuel cell (58 MW) and internal combustion engine (22 MW) projects. A large number of Post-SB 412 AES projects were completed in 2014 and 2015 but their small sizes limit the contribution to SGIP capacity.

Figure 3-3: Rebated Capacity by Technology Type Pre/Post-SB 412



SGIP projects are powered by a variety of renewable and non-renewable energy sources as shown in Figure 3-4. Non-renewable fuels such as natural gas powered the majority of SGIP projects. Onsite biogas projects typically use biogas derived from landfills or anaerobic digestion processes that convert biological matter to renewable fuel. Anaerobic digesters are used at dairies, wastewater treatment plants, or food processing facilities to convert wastes from these facilities to biogas.

In CPUC Decision 09-09-048 (September 24, 2009), SGIP eligibility was expanded to include "directed biogas" projects. Directed biogas projects use biogas fuel that is produced at a location other than the project site. The procured biogas is processed, cleaned-up, and injected into a natural gas pipeline for distribution. Although the purchased biogas is not likely to be delivered and used by the SGIP renewable fuel project, the directed biogas is notionally delivered and the SGIP is credited with the overall use of biogas resources. Beginning in PY11 the SGIP limited eligibility for directed biogas projects to in-state biogas sources only. One directed biogas project has been completed Post-SB 412.

In Figure 3-4 the 'Other' energy source group includes advanced energy storage, wind turbine, and pressure reduction turbine projects.

Figure 3-4: Rebated Capacity by Energy Source and Pre/Post-SB 412

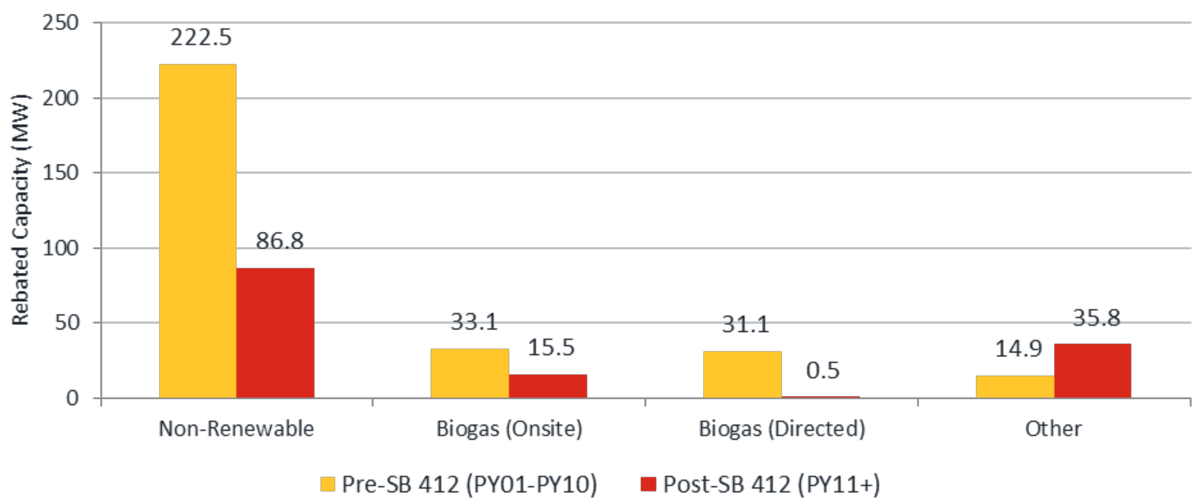
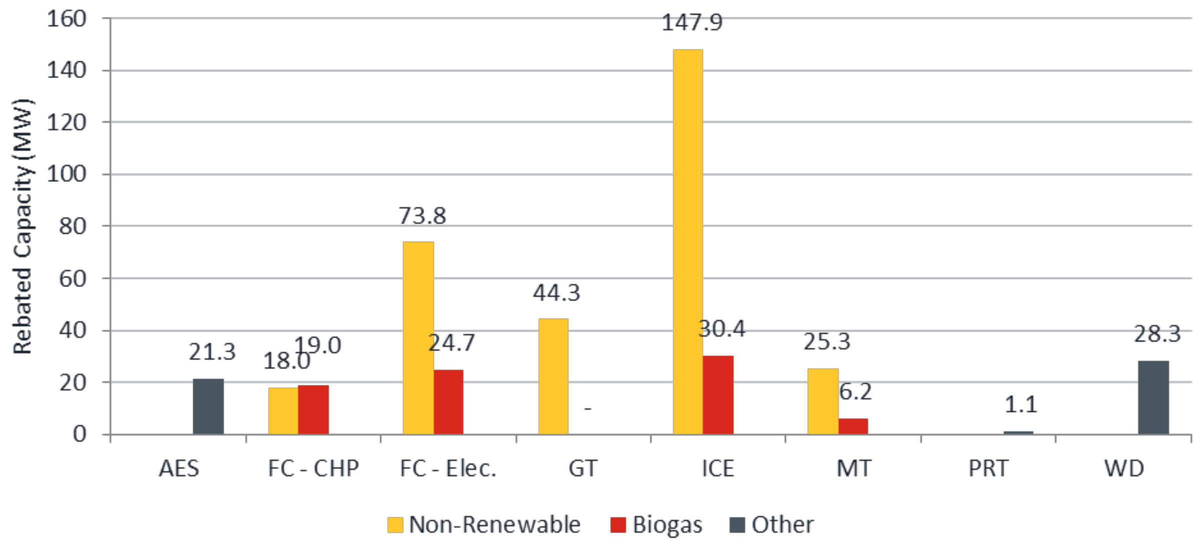


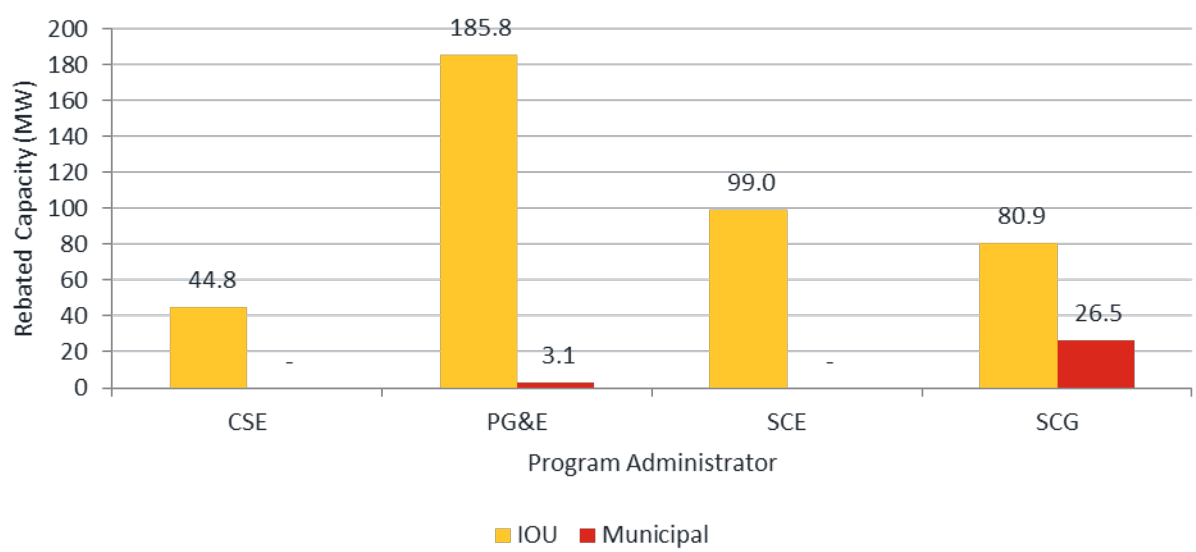
Figure 3-5 shows energy sources for each SGIP technology type. With the exception of gas turbines, all fuel-consuming technology types have projects powered by non-renewable natural gas and renewable biogas. All of the biogas used for electric-only fuel cells is directed biogas. Some CHP fuel cells are also fueled by directed biogas, but most are fueled by onsite biogas.

Figure 3-5: Rebated Capacity by SGIP Technology Type and Fuel Type



SGIP projects are electrically interconnected to load serving entities that are either investor owned (IOU) or municipal utilities. Figure 3-6 shows each PA's rebated capacity by electric utility type. Seven percent of the SGIP rebated capacity is interconnected to municipal utilities; the remaining capacity offsets IOU electricity purchases. Any project interconnected to a municipal electric utility must be served by a gas IOU. Almost all of the capacity interconnected with municipal utilities is administered by SCG. Of the 80.9 MW administered by SCG interconnected to IOUs, 75.2 MW are served by SCE. The remaining IOU capacity is served by PG&E and SDG&E. All projects administered by CSE and SCE are interconnected to IOUs.

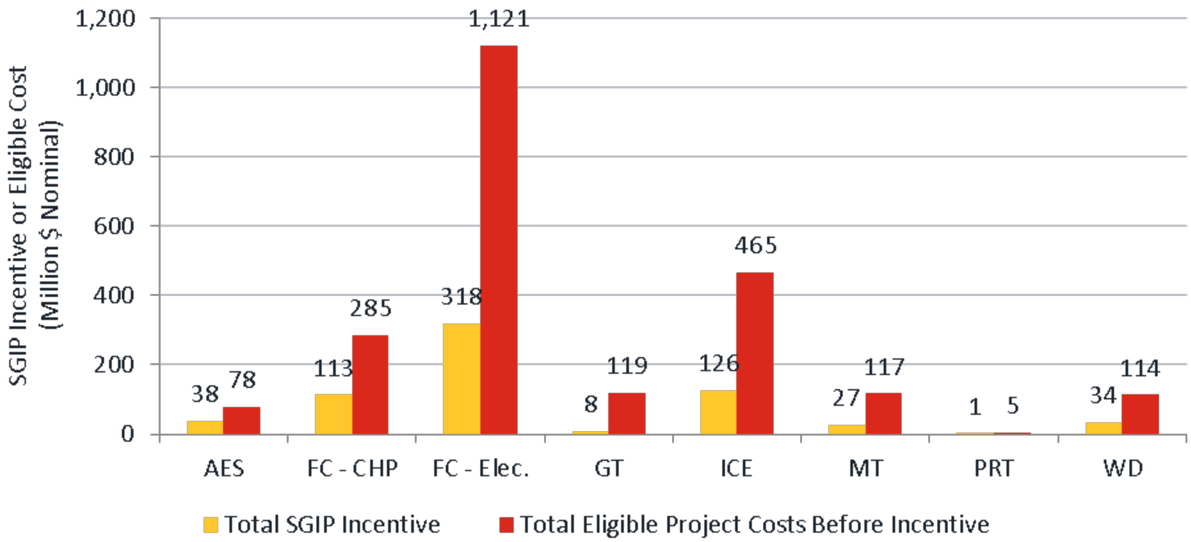
Figure 3-6: Rebated Capacity by Program Administrator and Electric Utility Type



Incentives Paid, Eligible Costs to Date

By the end of 2015 the SGIP had allocated over 656 million dollars in incentives for completed projects (excluding PV).[12] Eligible costs[13] reported by applicants surpassed 2.3 billion dollars. Figure 3-7 shows the breakdown of incentives paid by the SGIP and costs reported by applicants for each technology type.

Figure 3-7: Cumulative Incentives Paid and Reported Eligible Costs by Technology Type



3.3 Status of the Queue

Projects that were not paid on or before December 31, 2015, and have not had their applications cancelled, rejected, or withdrawn remain in the SGIP queue. As of June 2016, there were 1,959 projects representing 465 MW of capacity in the SGIP queue. Figure 3-8 summarizes the SGIP queue by technology type.

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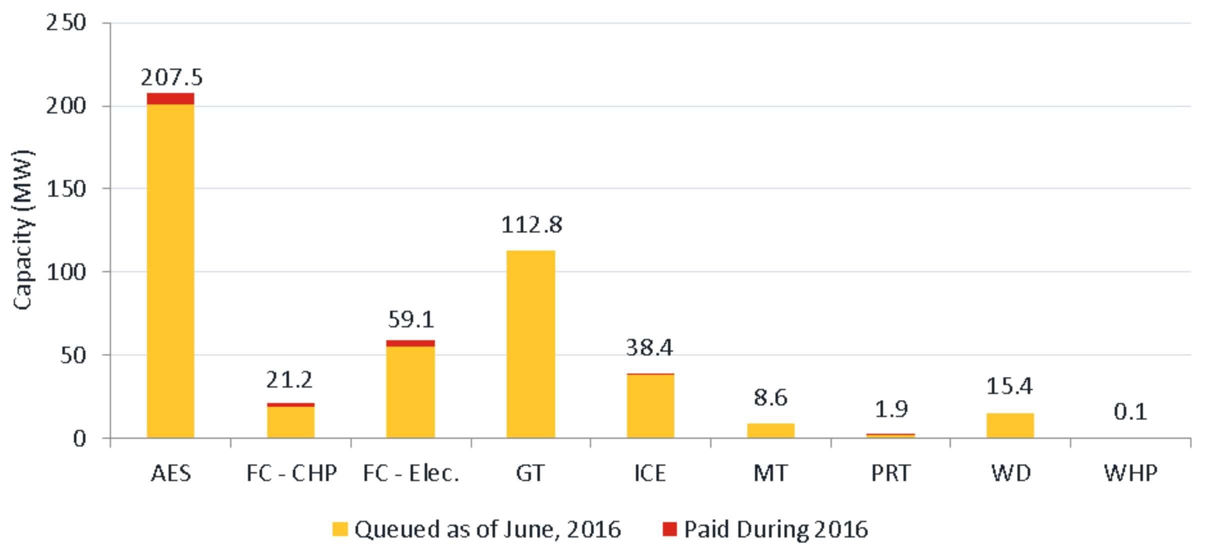
[12] For the purposes of this report, all projects are assumed to receive their entire reserved incentive amount, regardless of PBI performance.

[13] Eligible costs are defined in the SGIP handbook.

Figure 3-8: SGIP Queue by Technology Type



Of the 1,959 projects in the queue, 230 were completed during 2016 and, therefore, are not included in the analysis of energy, demand, and environmental impacts occurring during 2014 and 2015. The remaining 1,729 projects are making their way through the queue, and may either receive incentive payments or exit the queue. The SGIP queue is composed primarily of advanced energy storage and gas turbine projects. Of the 13.2 MW of projects paid in 2016, 6.9 MW are advanced energy storage projects.

During its fifteenth year, the SGIP provided incentives to 1,144 projects representing over 440 MW of rebated capacity. The SGIP boasts eight different technology types that are powered by a variety of energy sources. These projects entered the SGIP program in different program years and are, therefore, subject to different program rules as described in the SGIP handbooks. The following section describes the sources of data and the analytic methodology used to evaluate the impacts of the SGIP during 2014 and 2015. Appendix A includes more detailed program statistics.

Sources of Non-AES Data and Estimation Methodology

4

4 SOURCES OF DATA AND ESTIMATION METHODOLOGY

This section provides an overview of the primary sources of data and the ratio estimation methodology used to quantify the energy and peak demand impacts of the Self-Generation Incentive Program (SGIP).

The primary sources of data include:

- The statewide project list managed by the Program Administrators (PAs)
- Site inspection and verification reports completed by the PAs or their consultants
- Metered electricity, fuel, and useful heat recovery data provided by the utilities, applicants, performance data providers (PDPs), and meters installed by Itron and its subcontractors
- Interval load data provided by the electric utilities
- Responses from the operations status surveys conducted by Itron

This section is not meant to be a comprehensive overview of the analysis but instead provides a high level review of the methodology. A more detailed discussion of sources of data and analytic methodology is provided in Appendix B. An overview of the environmental impacts methodology is provided in Appendix C and Appendix D. The treatment of measurement and sampling uncertainty is discussed in Appendix E.

4.1 Statewide Project List and Site Inspection Verification Reports

The statewide project list forms the "backbone" of the impacts evaluation as it contains information on all projects that have applied to the SGIP. Critical fields from the statewide project list include:

- Project tracking information such as the reservation number, facility address, program year, payment status/date, and eligible/ineligible cost information
- Project characteristics including technology/fuel type, rebated capacity, and equipment manufacturer/model

Data obtained from the statewide project list are verified and supplemented by information from site inspection verification reports. The PAs or their consultants perform site inspections to verify that installed SGIP projects match the application data and to ensure they meet minimum requirements for program eligibility. Itron reviews the inspection verification reports to verify and supplement the information in the statewide project list. Additional information in verification reports includes descriptions of useful heat recovery end uses for combined heat and power (CHP) projects and identification of existing metering equipment that can be used for impact evaluation purposes.

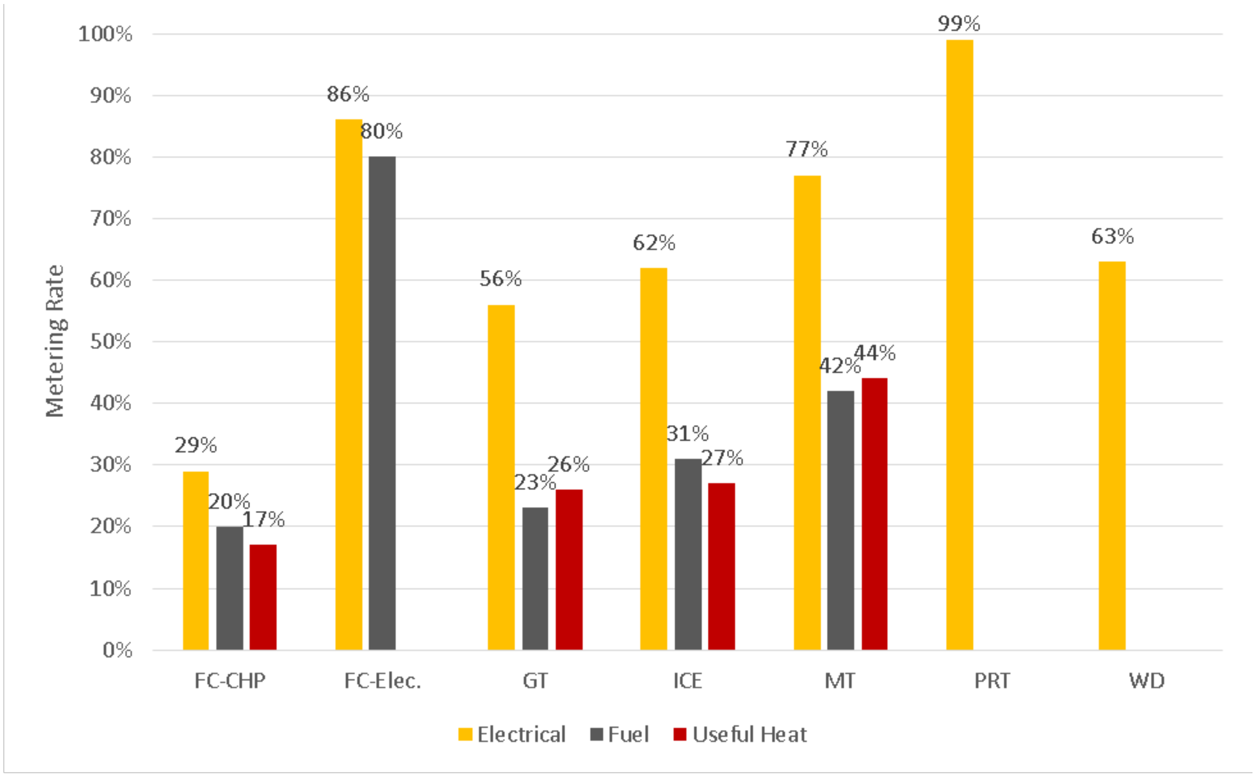
4.2 Metered Data

Metered electricity, fuel consumption, and useful heat recovery data form the basis of this impacts evaluation. Metered data are requested and collected from electricity/gas distribution companies, system manufacturers, host customers, and applicants. Itron and its subcontractors installed meters based on a sampling approach designed to achieve statistically significant impacts estimates at the 90/10 confidence/precision level. In total, 17 distinct data providers provided metered data for 469 projects whose 2014-2015 impacts were evaluated. The data are processed, validated, and converted into standard format datasets. The processing and validation steps include:

» Conversion of timestamps to Pacific Standard Time, including adjustment for Daylight Savings Time
» Standardization of interval length and units of measure:
  > All electrical generation data are converted to 15-minute net generator output kWh
  > All fuel consumption data are converted to 15-minute MBtu[1]$_{LHV}$ assuming 935 Btu/SCF[2]
  > All useful heat recovery data are converted to 15-minute MBtu
» Suspect observations are flagged, investigated, and removed if necessary

All valid metered data are cataloged in a library and added to the backbone of projects built from the statewide project list. The result is a backbone that is partially fleshed out with metered data but has gaps that result from metering equipment issues or projects outside the metered sample. Figure 4-1 shows metering rates for calendar years 2014 and 2015, defined as the number of hours for all projects during 2014 and 2015 with metered data over the number of hours for all projects during 2014 and 2015. These metering rates are unweighted and, therefore, do not reflect the relative importance of metering large projects.

Figure 4-1: Metering Rates by Technology Type (2014 and 2015 Combined)



1 During the combustion of hydrocarbon fuels, some of the oxygen is combined with hydrogen, forming water vapor that may leave the combustion device either in vapor or condensed to liquid state. When the latent heat of vaporization is extracted from the flue products, causing the water to become liquid, the fuel's energy density is identified as higher heating value (HHV). When the equipment used allows the water to remain in the vapor state, the energy density is identified as lower heating value (LHV). (Petchers, 2003.)

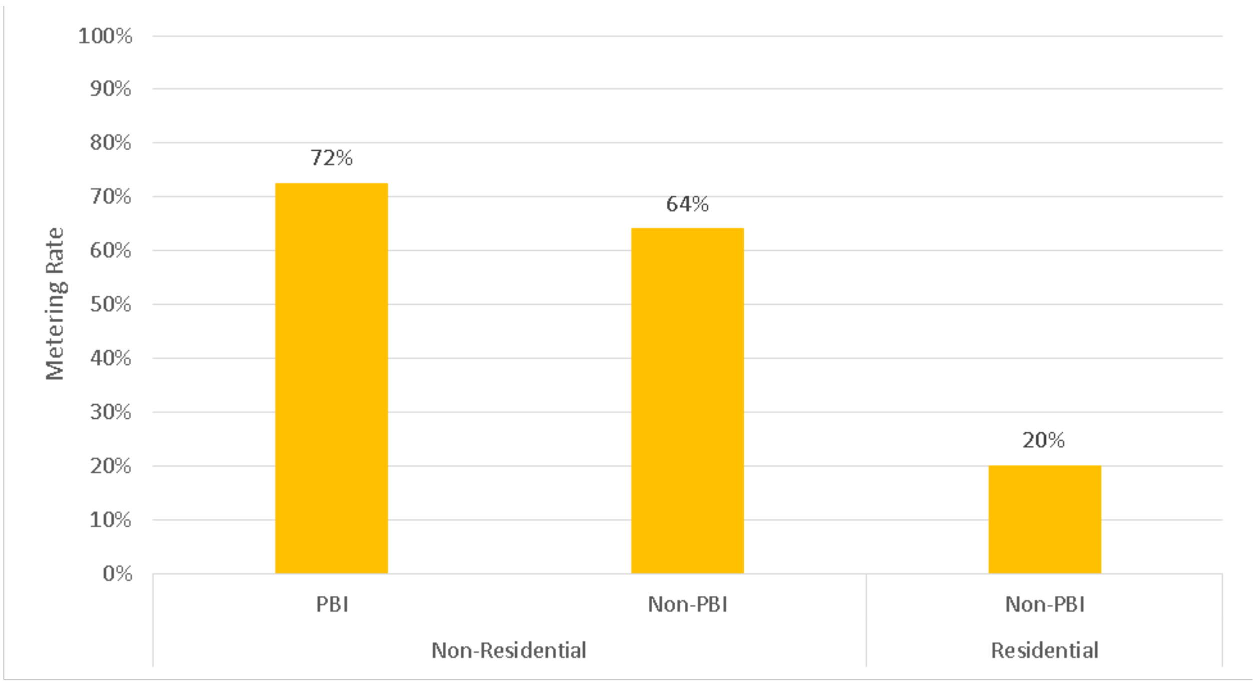
2 Combined Heating, Cooling & Power Handbook: Technologies & Applications. Neil Petchers. The Fairmont Press, 2003.

Observations with missing values (either due to gaps in metered data or due to the sample design) cannot be ignored and their values must be estimated. These observations are estimated using the operations status survey and ratio estimation.

4.3 Metered Advanced Energy Storage Data

Like other metered data, metered advanced energy storage (AES) charge and discharge data form the basis of this impacts evaluation. Metered data are requested and collected from system manufacturers for non-PBI projects and from Energy Solutions for projects that received a PBI incentive. For non-PBI projects, data were available to include in this report from one AES provider focused on the non-residential sectors and one AES provider focused on the residential sector. The data received from the non-residential focused provider were anonymized to protect customer information. Figure 4-2 shows the metering rates for AES projects in 2015. Note that in 2014, data from only two PBI projects were available.

Figure 4-2: Metering Rates for AES Projects (2015)



Section 6 has more detail on the AES metered charge and discharge data received and some of the issues associated with some of those data.

4.4 Interval Load Data

Interval load data for each project was requested from Pacific Gas & Electric (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E) for 2013, 2014, and 2015. These data were requested to allow analysis of noncoincident peak (NCP) demand impacts and to better analyze AES dispatch. Due to the confidential nature of customer load data, we signed nondisclosure agreements (NDAs) with each of the utilities and PAs to obtain the load data. However, because of the legal and financial ramifications of possible exposure of confidential customer data, even inadvertently, obtaining approval of the NDAs from all involved parties took an extensive amount of time. In addition, the requirement that all customer data be anonymized let to problems in matching customer load data to storage or generation data. As a result, the success of matching SGIP project information to load data varied by utility.

- PG&E was able to match SGIP projects based on customer name and address for 339 projects.
- SCE was able to match SGIP projects based on customer name and address for 180 projects.
- SDG&E was able to match SGIP project information to load data only for projects from which we had collected meter numbers from inspection reports. There were a total of 128 projects, which were almost entirely comprised of AES projects.

Once load data were received and processed, we matched them to available generation or charge/discharge data (for AES) to allow project-by-project analysis of the customer demand impacts of SGIP. Table 4-1 list the counts by Pre or Post-SB 412 status, system type, PA, and year.

Table 4-1: Projects with Matched Load and Generation Data

	PG&E		SCE		Grand Total
	2014	2015	2014	2015	
Post-SB 412	**10**	**35**	**22**	**30**	**97**
Fuel Cell - CHP		2		2	4
Fuel Cell - Elec.	9	27	17	23	76
Internal Combustion Engine		1	1	1	3
Microturbine	1	4	1	1	7
Pressure Reduction Turbine		1			1
Wind			3	3	6
AES (PBI)	2	8		4	12
Pre-SB 412	**14**	**7**	**53**	**50**	**124**
Fuel Cell - CHP	2	1	3	1	7
Fuel Cell - Elec.	12	6	15	14	47
Internal Combustion Engine			17	16	33
Microturbine			16	17	33
Wind			2	2	4
Grand Total	**24**	**42**	**75**	**80**	**221**

Although we received load data from SDG&E, they were matched only to AES projects. Unfortunately, the metered AES data for all of these projects was either not available or of questionable quality. The lack of matched data sets was a significant problem in conducting evaluation of AES performance and the SGIP's ability to address aggregate noncoincident customer peak demand impacts.

4.5 Operation Status Surveys

Operations status surveys represent the first attempt at filling metered data gaps. The surveys target SGIP hosts whose backbone is lacking large amounts of metered data. Sixty-one projects were targeted for the 2014-2015 operations status survey, which had a success rate of 59%. The survey seeks to determine if periods without metered data fit into one of three categories:

» **Normal,** the system was online and operating normally during the period in question.

» **Off,** the system did not generate electricity during the period in question but is still installed at the host site.

» **Decommissioned,** the system has been physically removed from the host site and will never operate again.

Hosts that respond with an "Off" operational status have zero energy generation assigned to the backbone during the time period in question. Similarly, hosts who respond with a decommissioned operational status have zeros added to the backbone starting from the date the system was decommissioned through the remainder of the evaluation period. Projects whose operational status is "Normal" and projects with data gaps but no operational status information must have missing observations estimated.

4.6 Ratio Estimation

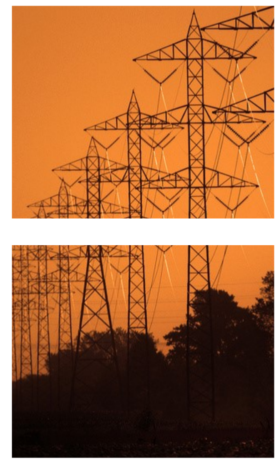
At this point in the estimation process, the project backbone was built with the contents of the statewide project list, validated by information from installation verification reports, and fleshed out with metered data and information from operational status surveys. The remaining observations contain missing values and must be estimated.

Ratio estimation is used to generate hourly estimates of performance for periods where observations would otherwise contain missing values. The premise of ratio estimation is that the performance of unmetered projects (projects outside the sample or projects in the sample with gaps in metered data) can be estimated from projects with metered data using a "ratio estimator" and an "auxiliary variable". The ratio estimator is calculated from the metered sample and the auxiliary variable is used to apply the estimator to the unmetered portion of the backbone. Table 4-2 summarizes the characteristics of the ratio estimation.

Table 4-2: Ratio Estimation Parameters

Variable Estimated	Ratio Estimator	Auxiliary Variable	Stratification
Electricity Generation (kWh)	Capacity Factor (kWh/kW·hr)	Rebated Capacity (kW)	Hourly, by technology type, fuel type, PA, operations status, incentive structure, capacity category, and warranty status
Fuel Consumption (MBtu)	Electrical Conversion Efficiency (unitless)	Electricity Generated (kWh)	Annual, by technology type and incentive structure
Useful Heat Recovered (MBtu)	Useful Heat Recovery Rate (MBtu/kWh)	Electricity Generated (kWh)	Annual, by technology type and incentive structure

The outcome of the ratio estimation process is fully fleshed out backbones with all metered data gaps filled with estimated electricity, fuel, and useful heat recovery values. These datasets form the basis of the energy, demand, and environmental impacts evaluation findings that are presented in Section 5 through Section 8. A discussion of the treatment of measurement and sampling uncertainty is included in Appendix E.



5 Non-AES Energy Impacts

5 NON-AES ENERGY IMPACTS

5.1 Summary of Energy Impacts

This summary describes electrical, thermal, and fuel energy impacts and related performance measures for program populations at ends of 2014 and 2015 as well as trends since 2003.[1] It includes annual program totals as well as various subtotals by Program Administrator (PA), technology, pre-SB 412 vs post-SB 412, and fuel. The last section compares impacts and performances of projects in the program with (post-SB 412) versus without (pre-SB 412) performance based incentives.

5.2 Electrical Generation Impacts

Electrical generation impacts are defined as kilowatt-hours that SGIP systems generate onsite. In this way the projects avoid taking these kWh from the grid. Impacts of interest are those coincident with peak hours for the California Independent System Operator (CAISO) and Investor Owned Utilities (IOUs) as well as totals over all hours of calendar years. Generation coincident with peak hours yields demand impacts described in units of kW, MW, or GW. Annual generation impacts are described in units of MWH, GWH, or TWH.

For many SGIP projects and most every PBI system, we determine generation based on metered generation data recorded every 15-minutes and gathered from various data providers including the IOUs.[2] Where metered generation data are not available or are deemed unrepresentative after careful review, we estimate hourly generation based on metered data from similar projects during similar periods.[3] The basis of all impact measures described here thus is the sum of actual metered generation and generation estimates. Table 5-1 and Table 5-2 list for 2014 and 2015 respectively the percentages of annual generation that was estimated by technology and PA.

[1] Excluding advanced energy storage and legacy PV projects. AES system impacts are described in a separate section.

[2] As of 9/1/16, the EnergySolutions website from which PBI data are gathered (https://www.selfgenca.com) has no data for eight projects that received initial PBI payment before 2016. Data previously available for the program's largest system also have been removed from the website.

[3] Appendix B describes estimation methods in greater detail.

Table 5-1: 2014 Percent of Annual Electric Generation Estimated by Technology and PA

Technology Type	Fuel Cell – CHP	Fuel Cell – Electric Only	Gas Turbine	Internal Combustion Engine	Microturbine	Pressure Reduction Turbine	Wind	Total
CSE	3.6%	23.5%	0.0%	17.3%	2.7%	0.6%	0.0%	**6.9%**
PG&E	12.9%	2.2%	94.9%	60.0%	22.8%	na	64.0%	**26.8%**
SCE	33.5%	8.5%	na	41.4%	45.7%	na	16.7%	**22.2%**
SCG	51.5%	0.4%	13.5%	32.9%	8.9%	na	na	**20.0%**
Total	**24.5%**	**5.1%**	**13.5%**	**45.9%**	**21.2%**	**0.6%**	**31.3%**	**21.2%**

CSE = Center for Sustainable Energy, PG&E = Pacific Gas & Electric, SCE = Southern California Edison, SCG = Southern California Gas Company

Table 5-2: 2015 Percent of Annual Electric Generation Estimated by Technology and PA

Technology Type	Fuel Cell – CHP	Fuel Cell – Electric Only	Gas Turbine	Internal Combustion Engine	Microturbine	Pressure Reduction Turbine	Wind	Total
CSE	1.7%	20.6%	11.4%	0.3%	6.9%	1.1%	0.0%	**10.4%**
PG&E	12.2%	25.4%	24.6%	58.7%	37.2%	0.0%	33.8%	**33.6%**
SCE	59.1%	11.6%	na	53.0%	47.5%	na	16.8%	**29.5%**
SCG	47.6%	16.4%	51.3%	39.4%	5.5%	na	na	**35.7%**
Total	**25.1%**	**20.2%**	**31.1%**	**50.1%**	**30.7%**	**0.7%**	**22.9%**	**30.2%**

- In 2014, 21.2% of total annual generation was estimated
- In 2015, 30.2% of total annual generation was estimated
- Percentages of estimated total annual generation increased from 2014 to 2015 for all PAs
- Availability of metered data for pre-SB 412 all-electric fuel cells and gas turbines dropped sharply from 2014 to 2015
- CSE had lowest percentages of total annual generation estimated in 2014 and 2015

Electrical generation impacts described here are net of losses or auxiliary loads SGIP projects themselves may have such as cooling pumps and fuel compressors. Impacts described here do not include secondary electrical impacts. Secondary impacts include avoided electric chiller demand where recovered useful heat serves an absorption chiller. Impacts described here also do not include transmission and distribution losses that electric utilities avoid by not having to supply the kWh that SGIP participants generate.

Annual Electric Generation

The annual electric generation program totals and Program Administrator (PA) subtotals are listed in Table 5-3 for 2014 and 2015.

Table 5-3: 2014 and 2015 Annual Electric Generation by PA (GWH)

Year	2014		2015	
PA	Electric Generation	Percent of total	Electric Generation	Percent of total
CSE	147	12.9%	180	13.6%
PG&E	417	36.6%	552	41.5%
SCE	222	19.5%	251	18.9%
SCG	353	31.0%	346	26.1%
Total	**1,138**	**100%**	**1,329**	**100%**

SGIP projects generated over 1,000 GWH in both 2014 and 2015, reaching 1,329 GWH in 2015. This is equivalent to approximately 0.5% of California's total in-state generation.[4] Generation grew over 16% from 2014 to 2015. The addition from 2014 to 2015 of new generating capacity among non-AES projects drove this growth in annual generation.

PG&E projects contributed the largest portions with 36.6% and 41.5% of annual generation in 2014 and 2015 respectively. PG&E projects contributed over 550 GWH in 2015. PG&E added over 36 MW of new capacity in 2015.

SCG project contributions were next largest after PG&E. They declined slightly from just above to just below 350 GWH from 2014 to 2015. SCG added almost 5 MW of new capacity in 2015.

SCE project contributions grew to just above 250 GWH in 2015. SCE added almost 14 MW of new capacity in 2015. SCE's portion fell slightly from 19.5% to 18.9% of annual generation due to the large increase in PG&E capacity.

CSE project contributions grew from 147 to 180 GWH from 2014 to 2015. CSE added 7.1 MW of new capacity in 2015. CSE's portion grew slightly from 12.9% to 13.69%.

New program capacity is post-SB 412 capacity. Pre-SB 412 capacity may increase only for those few projects that have been years in coming to completion. Table 5-4 and Figure 5-1 show annual generation in 2014 and 2015 by PA and pre-and post-SB 412.

4 According to California Energy Commission 199 and 196 TWh were generated in-state in 2014 and 2015 respectively. See http://energyalmanac.ca.gov/electricity/electric_generation_capacity.html

Table 5-4: 2014 and 2015 Annual Electric Generation by PA and SB 412 Pre/Post (GWH)

Year	2014			2015		
PA	**PRE**	**POST**	**POST-SB 412 %**	**PRE**	**POST**	**POST-SB 412 %**
CSE	130	16.9	11.5%	126	54.6	30.3%
PG&E	349	67.5	16.2%	307	245	44.4%
SCE	159	63.1	28.4%	133	118	47.0%
SCG	304	48.7	13.8%	262	84.0	24.2%
Total	**941**	**196**	**17.2%**	**828**	**502**	**37.7%**

Table 5-4 shows that contributions to annual generation from post-SB 412 projects more than doubled between 2014 and 2015, from 196 to 502 GWH. The post-SB 412 contribution grew from 17.2% to 37.7% of total annul generation. Pre-SB 412 projects continue to dominate annual generation but declined in 2015, falling from 941 to 828 GWH.

From 2014 to 2015, all PAs had declining contributions from their pre-SB 412 projects and increasing contributions from their post-SB 412 projects. Post-SB 412 contributions almost tripled for CSE and PG&E. For CSE growth went from 11.5% to 30.3%, and for PG&E from 16.2% to 44.4%. SCE and SCG had more modest growth. For SCE, post-SB 412 contributions in 2015 reached 47% of total annual generation.

Figure 5-1: 2014 and 2015 Annual Electric Generation by PA and SB 412 Pre/Post

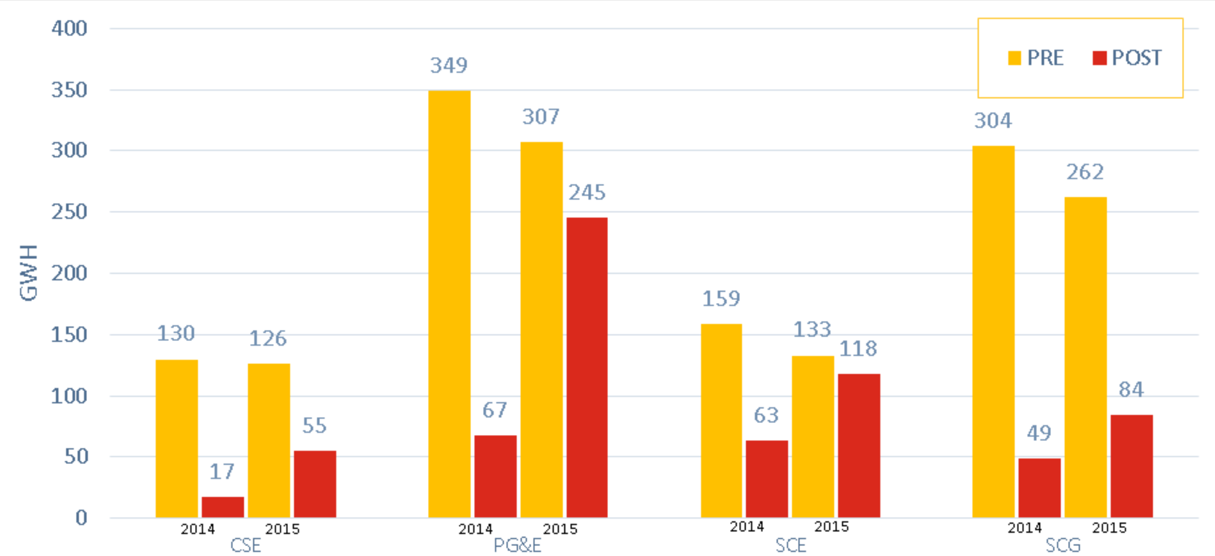


Figure 5-1 shows declining contributions from pre-SB 412 capacity in yellow and increasing contributions from post-SB 412 in red for all PAs between 2014 and 2015. Post-SB 412 contributions nearly reached pre-SB 412 contributions for PG&E in 2015. Similar growth from 2014 to 2015 can be seen for post-SB 412 capacity.

Figure 5-2: 2014 and 2015 Annual Electric Generation by Technology

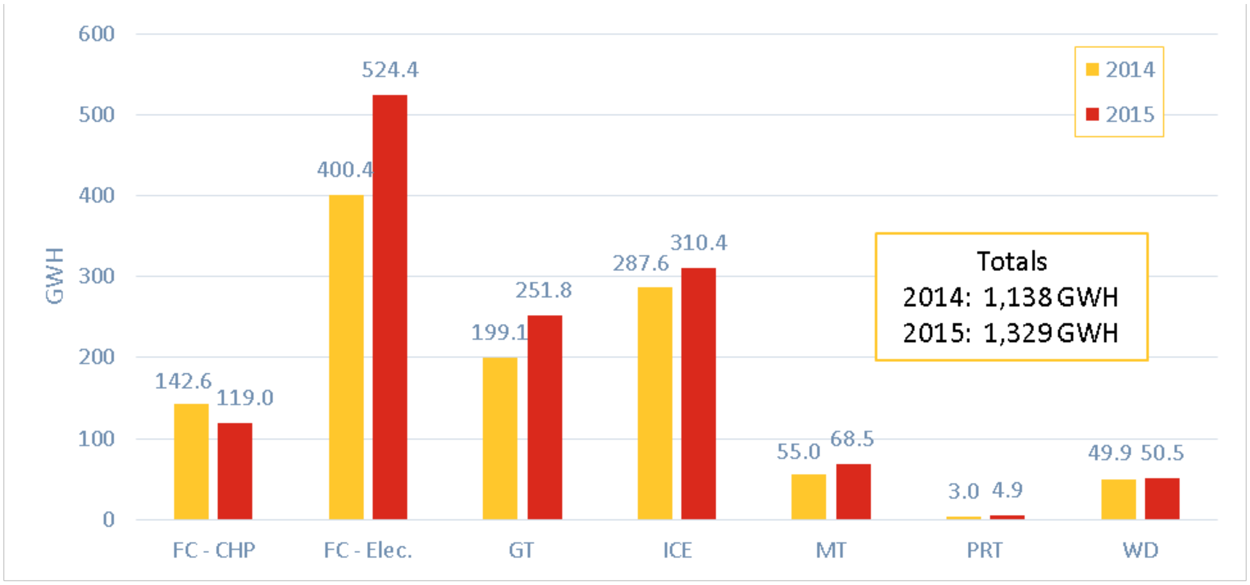


Figure 5-2 shows 2014 and 2015 annual generation by technology for the seven technologies addressed in this section. All technologies but CHP fuel cells increased generation from 2014 to 2015. CHP fuel cell generation fell despite adding 2.4 MW. Retirement of older CHP fuel cell capacity explains the decline. Wind remained near flat despite 3.6 MW of new capacity.

All-electric fuel cells and internal combustion engines continued to contribute the largest portions to annual generation in 2014 and 2015. All-electric fuel cell generation increased in 2015 by over 120 GWH. IC engine generation increased by less than 25 GWH. Gas turbine generation increased by over 50 GWH. Pressure reduction turbines were the smallest contributor but had the largest relative growth, over 60% between 2014 and 2015.

Annual generations by PA and technology are shown for 2014 and 2015 in Table 5-5 and Table 5-6 respectively.

Table 5-5: 2014 Annual Electric Generation by PA and Technology (MWH)

Technology Type	Fuel Cell - CHP	Fuel Cell - Electric Only	Gas Turbine	Internal Combustion Engine	Microturbine	Pressure Reduction Turbine	Wind	Total
CSE	38.5	32.2	64.0	6.3	1.6	3.0	0.9	**146**
PG&E	38.9	193.3	10.5	124.1	34.0	na	15.7	**417**
SCE	28.1	98.5	0.0	56.2	5.8	na	33.2	**222**
SCG	37.1	76.4	124.6	101.0	13.5	na	0.0	**352**
Total	**142.6**	**400.4**	**199.1**	**287.6**	**55.0**	**3.0**	**49.9**	**1,137**

Table 5-6: 2015 Annual Electric Generation by PA and Technology (MWH)

Technology Type	Fuel Cell - CHP	Fuel Cell - Electric Only	Gas Turbine	Internal Combustion Engine	Microturbine	Pressure Reduction Turbine	Wind	Total
CSE	36.5	34.5	95.7	6.0	0.9	2.9	3.9	**180**
PG&E	35.4	270.0	47.6	133.1	42.1	1.9	21.9	**552**
SCE	21.9	123.0	0.0	71.8	9.3	na	24.7	**251**
SCG	25.2	97.0	108.5	99.4	16.2	na	0.0	**346**
Total	**119.0**	**524.4**	**251.8**	**310.4**	**68.5**	**4.9**	**50.5**	**1,329**

From 2014 to 2015, CSE had modest increases in generation from its all-electric fuel cell and IC engine projects. Nearly half of growth in generation from 2014 to 2015 for PG&E was from its all-electric fuel cell projects. PG&E had modest increases from its other technologies apart from CHP fuel cells where generation declined in 2015. SCE had substantial increases from 2014 to 2015 from its all-electric fuel cell and IC engine projects. SCE wind projects on the other hand had reduced generation in 2015. For SCG only all-electric fuel cells and microturbines had increased generation from 2014 to 2015.

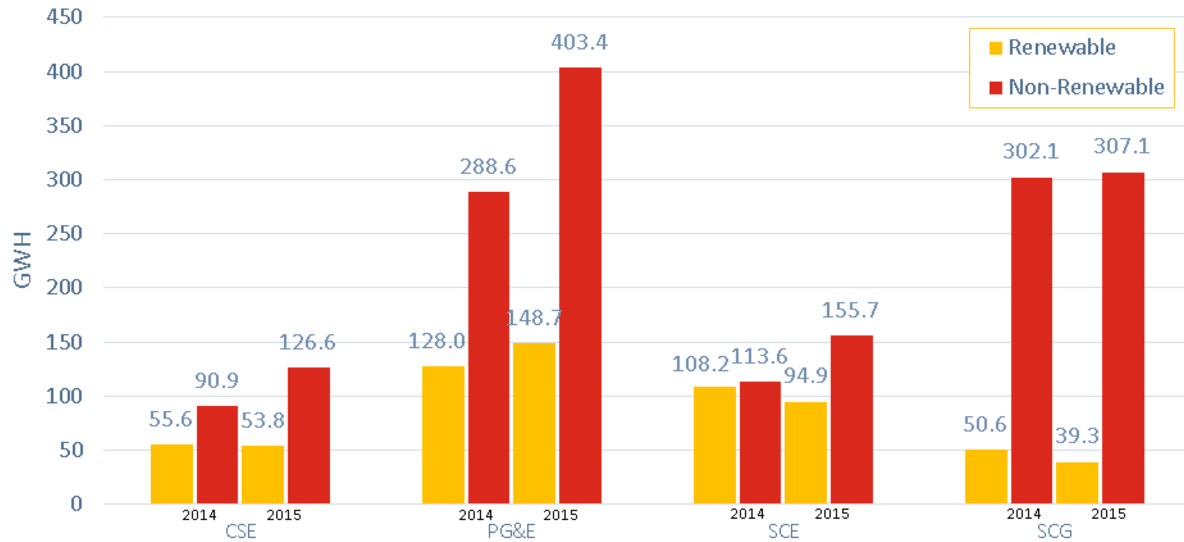
SGIP projects are fueled by a variety of energy sources. Renewable energy sources include on-site and directed biogas, wind, and hydro (for pressure reduction turbines). The non-renewable energy source is natural gas. Table 5-7 and Figure 5-3 show 2014 and 2015 annual electric generation by fuel category and PA.

Table 5-7: 2014 and 2015 Annual Electric Generation by PA and Fuel (GWH)

Year	2014			2015		
PA	Renewable	Non-Renewable	Renewable %	Renewable	Non-Renewable	Renewable %
CSE	55.6	90.9	38.0%	53.8	126.6	29.8%
PG&E	128.0	288.6	30.7%	148.7	403.4	26.9%
SCE	108.2	113.6	48.8%	94.9	155.7	37.9%
SCG	50.6	302.1	14.3%	39.3	307.1	11.4%
Total	**342.4**	**795.2**	**30.1%**	**336.7**	**992.7**	**25.3%**

Table 5-7 shows renewable energy project contributions to total annual generation decreased slightly from 342.4 to 336.7 GWH between 2014 and 2015. The relative contribution fell from 30.1% to 25.3%. All PAs had declining relative contributions from renewables from 2014 to 2015, although PG&E's absolute contribution increased from 128 to almost 150 GWH. The red bars of Figure 5-3 show all PAs had increasing contributions from non-renewable fuel projects from 2014 to 2015.

Figure 5-3: 2014 and 2015 Annual Electric Generation by PA and Fuel



Annual Electric Generation Trend

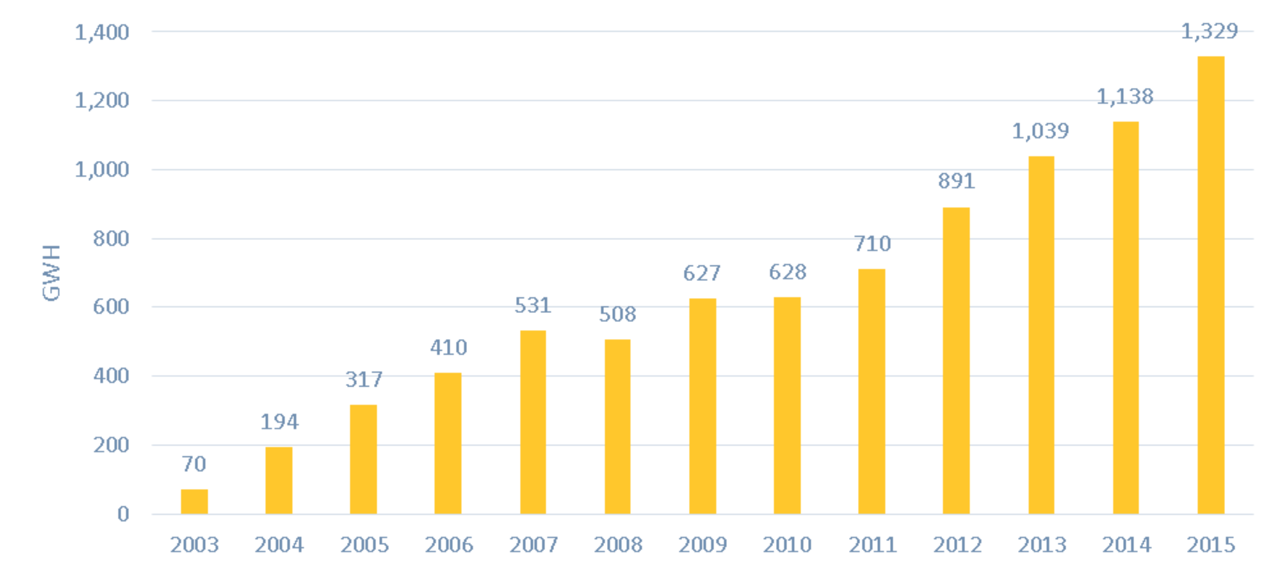
The program's annual electric generation has grown every year except 2008 when it declined slightly due to factors outside of the program's control.[5] While primarily a result of the program's continuing capacity growth, the annual generation growth trend is not strictly due to new projects. Annual generation fell in 2008 despite new capacity.

Without new projects, each year total annual generation would decline over time as aged projects were retired.[6] From 2014 to 2015 both capacity and annual generation grew by more than in any previous year. Capacity and annual generation growth were led by all-electric fuel cells and gas turbines. Figure 5-4 shows annual generation from 2003 to 2015.

5 Increases in natural gas price and air emissions regulations contributed to generation declines in 2008.

6 Some SGIP generators have been replaced after retirement but only original projects are considered to contribute to impacts.

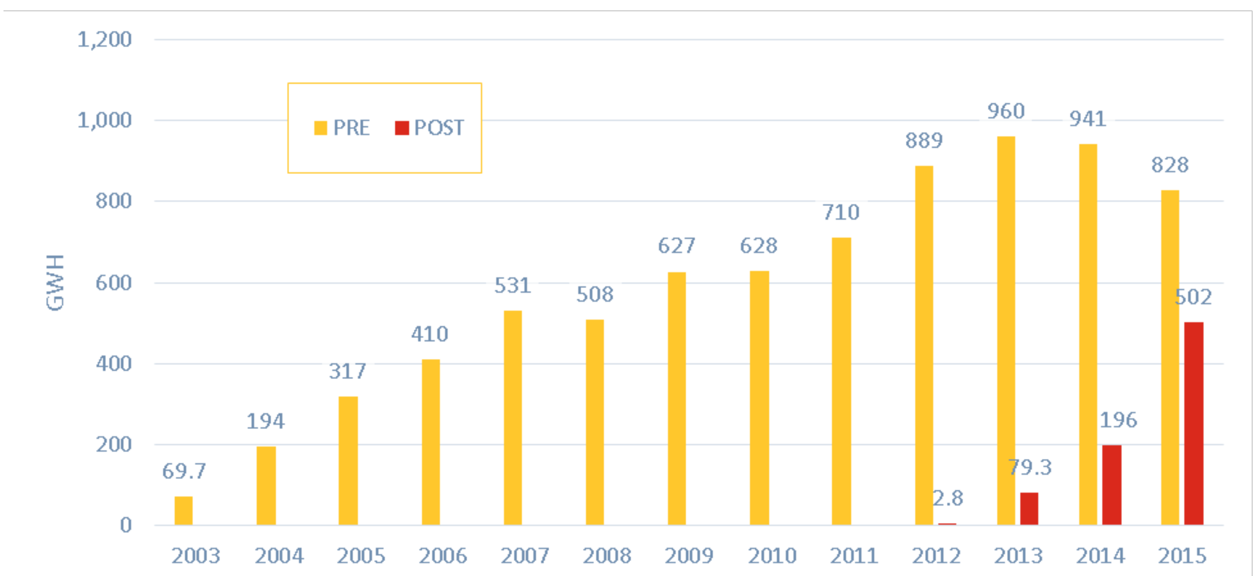
Figure 5-4: Annual Electric Generation by Calendar Year



Beginning in 2013 annual generation reached the 1 TWH mark. Annual generation grew 191 GWH from 2014 to 2015, the largest annual growth to date.

In 2012 the program added its first post-SB 412 capacity. Post-SB 412 projects of 30 kW or more entered under the program's performance-based incentive (PBI) agreement. The incentive structure encouraged PBI projects to deliver more annual generation on average than their pre-SB 412 counterparts. Figure 5-5 shows annual generation by SB 412 Pre/Post from 2003 to 2015.

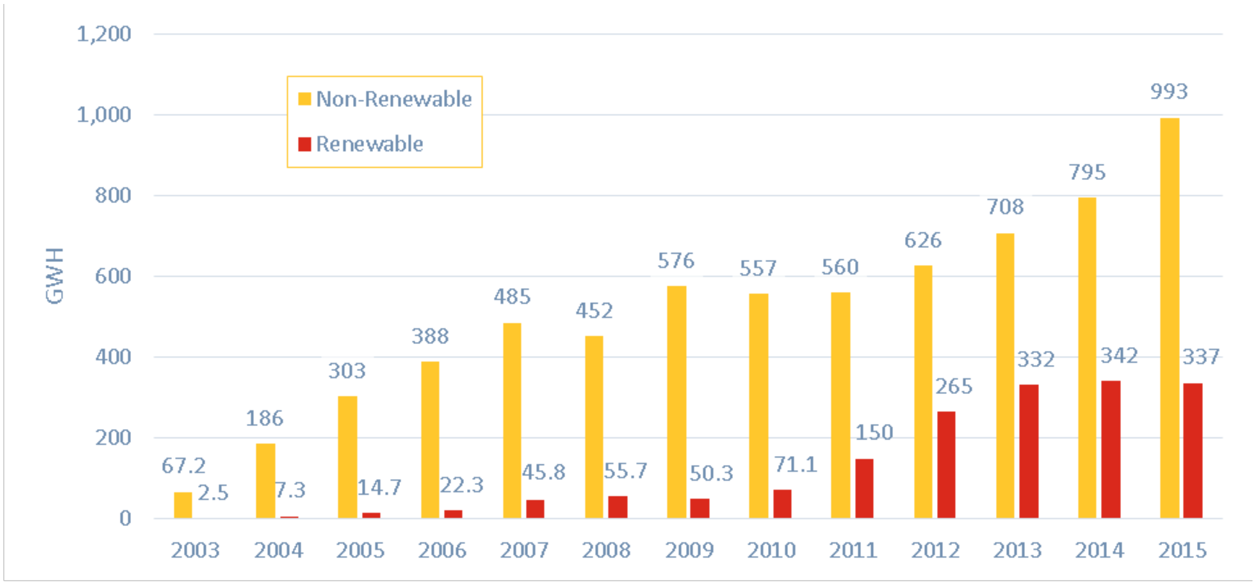
Figure 5-5: Annual Electric Generation by SB 412 Pre/Post



In 2013, post-SB 412 projects generated 79.3 GWH. By 2014, annual generation grew by almost 150% to 196 GWH. Growth over 2015 exceeded 155% to reach 502 GWH. From 2013 to 2015, annual generation from pre-SB 412 projects declined by almost 14%.

The program funded renewable-fueled projects in its early years and later added emphasis to increase the program's greenhouse gas emission reductions.[7] Renewable-fueled projects include wind turbines, pressure reduction turbines, and the combustion-based projects that consume biogas directly or indirectly. Figure 5-6 shows annual generation by non-renewable and renewable program capacity from 2003 to 2015.

Figure 5-6: Annual Electric Generation by Fuel

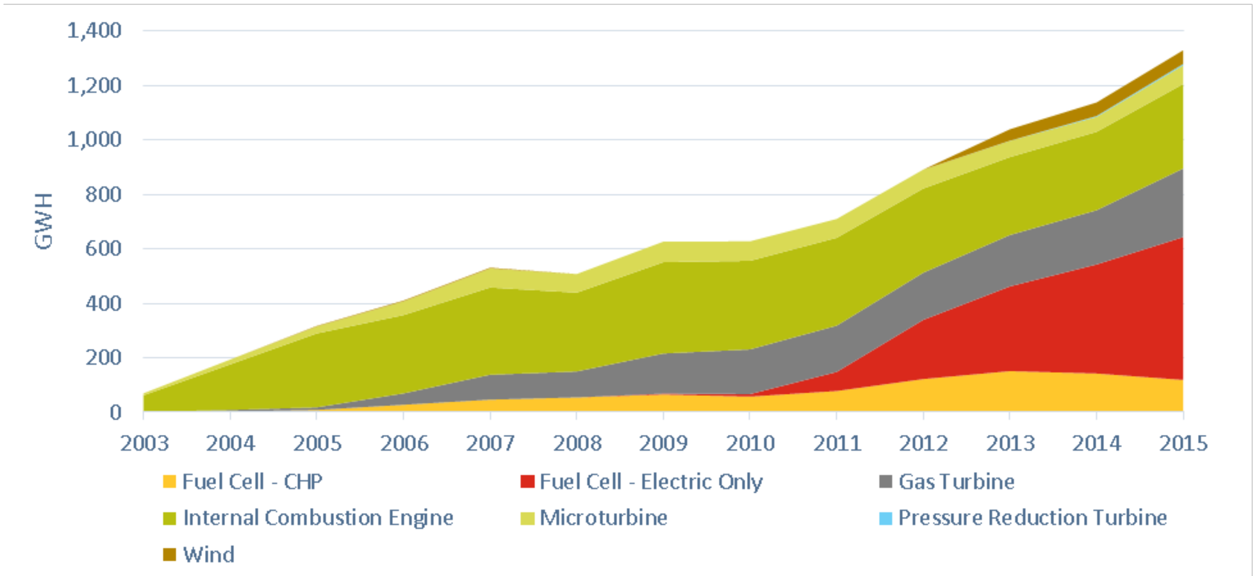


Non-renewable annual generation has outpaced renewable in every year. Non-renewable was just short of 1 TWH in 2015. Renewable annual generation has been steady from 2013 through 2015 near 340 GWH. The relative contribution from renewable peaked at 46.8% in 2013 and then declined in 2014 and 2015 as non-renewable annual generation has accelerated.

The program always has funded a mix of generation technologies. In this section, we address seven technologies with fuel cells including both all electric and CHP types. Figure 5-7 shows the composition of annual electric generation by technology from 2003 to 2015.

7 Disregarding solar PV projects funded in early years.

Figure 5-7: Annual Electric Generation by Technology



IC engines always have contributed a large share of the annual generation. Microturbines have contributed a small but steady amount since 2006. Gas turbines have contributed a steady amount since about 2009. Growth in annual generation since 2011 has been driven primarily by all-electric fuel cells. All-electric fuel cells have become and are likely to remain the predominant contributor to annual generation for several more years. CHP fuel cell annual generation peaked in 2013 and has declined slowly over 2014 and 2015. Wind contributes a small part to annual generation. Table 5-8 lists annual electric generation by technology from 2003 to 2015.

Table 5-8: Annual Electric Generation by Technology (GWH)

Technology Type	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Fuel Cell - CHP	1.70	3.02	8.86	27.6	46.6	54.8	65.4	57.6	78.2	122	151	143	119
Fuel Cell - Electric Only							3.18	9.17	70.1	218	311	400	524
Gas Turbine		5.53	9.41	41.9	91.4	95.4	147	164	170	173	189	199	252
Internal Combustion Engine	60.8	168	271	288	320	289	335	325	323	309	286	288	310
Microturbine	7.23	17.5	25.9	50.6	69.9	68.3	75.4	71.5	69.0	69.7	59.3	55.0	68.5
Pressure Reduction Turbine											0.56	3.02	4.86
Wind			1.89	2.49	2.75						42.2	49.9	50.5
Total	**69.7**	**194**	**317**	**410**	**531**	**508**	**627**	**628**	**710**	**891**	**1,039**	**1,138**	**1,329**

Since 2013 all-electric fuel cells, IC engines, and gas turbines have been the top contributing technologies to annual generation. All-electric fuel cells outpaced gas turbines in 2012 and IC engines in 2013. Gas turbines remain 3rd in terms of annual generation but in 2015 narrowed the gap with IC engines. IC engine annual generation rebounded from its fourth lowest year in 2014 to it third highest year in 2015. CHP fuel cell annual generation declined for the first time from 2014 to 2015.

Coincident Peak Demand Impacts

Coincident peak demand impacts are defined as the generation from SGIP projects during hours of CAISO or IOU peak demands. The single greatest annual CAISO or IOU peak hours provide brief snapshots of program coincident demand impacts. We consider generation during those hours as well as a more robust picture based upon average generation coincident with the annual top 200 CAISO and IOU peak hours.

By coincidentally generating at all during CAISO or IOU peak hours, SGIP system hosts allow their electric utility to avoid the purchase of high cost wholesale energy. At the same time the electric utility reduces its transmission and distribution losses during what typically are hours of high system congestion. Ideally, SGIP system hosts are generating at full capacity during peak hours and thus contributing the greatest possible demand impacts. However, these hours are not necessarily when an SGIP system host has its highest load or otherwise might want to be generating.

In this section, we examine generation during CAISO and IOU annual peak load hours as well as their top 200 load hours. We also look at year to year trends in program impacts. Table 5-9 lists hours and magnitudes of CAISO and IOU peak demands in 2014 and 2015.

Table 5-9: 2014 and 2015 CAISO and IOU Peak Hours and Demands (MW)

Year	2014			2015		
IOU	Peak Demand (MW)	Date	Hour Ending	Peak Demand (MW)	Date	Hour Ending
CAISO	44,671	Monday, Sep 15	4:00 PM	47,252	Thursday, Sep 10	4:00 PM
PG&E	19,526	Friday, July 25	4:00 PM	20,470	Monday, Aug 17	4:00 PM
SCE	22,987	Monday, Sep 15	4:00 PM	22,822	Tuesday, Sep 8	2:00 PM
SDG&E	4,864	Tuesday, Sep 16	2:00 PM	4,718	Wednesday, Sep 9	2:00 PM

CAISO Peak Hour

Generation coincident with the CAISO annual peak hours in 2014 and 2015 are shown by PA in Table 5-10.

Table 5-10: 2014 and 2015 CAISO Peak Hour Generation by PA (MW)

Year	2014		2015	
PA	Peak Hour Generation	Percent of total	Peak Hour Generation	Percent of total
CSE	18.9	13.0%	23.0	14.2%
PG&E	57.0	39.3%	68.3	42.1%
SCE	24.4	16.8%	32.8	20.2%
SCG	44.7	30.9%	38.1	23.5%
Total	**144.9**	**100%**	**162.2**	**100%**

Table 5-10 shows generation from SGIP projects of 144.9 MW coincident with the 2014 CAISO peak hour. This is equivalent to 0.32% of the 2014 CAISO peak. In 2015, SGIP projects generated 162.2 MW during the CAISO peak hour, equivalent to 0.34% of the 2015 CAISO peak. CAISO peak hour generation grew by a healthy 11.9% from 2014 to 2015.

PG&E projects contributed the largest portions of CAISO peak hour generation in both 2014 and 2015. SCG projects contributed second largest portions followed by SCE projects. Only SCG had a decline in peak hour generation from 2014 to 2015.

Figure 8 and Table 11 show peak hour generation by PA and SB 412 Pre/Post.

Figure 5-8: 2014 and 2015 CAISO Peak Hour Generation by PA and SB 412 Pre/Post

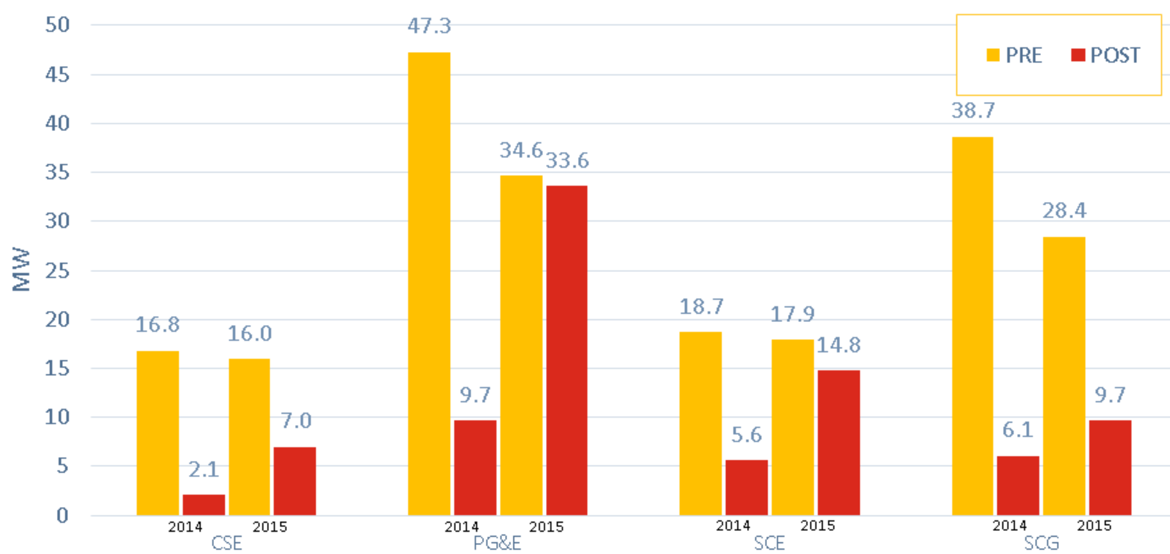


Table 5-11: 2014 and 2015 CAISO Peak Hour Generation by PA and SB 412 Pre/Post (MW)

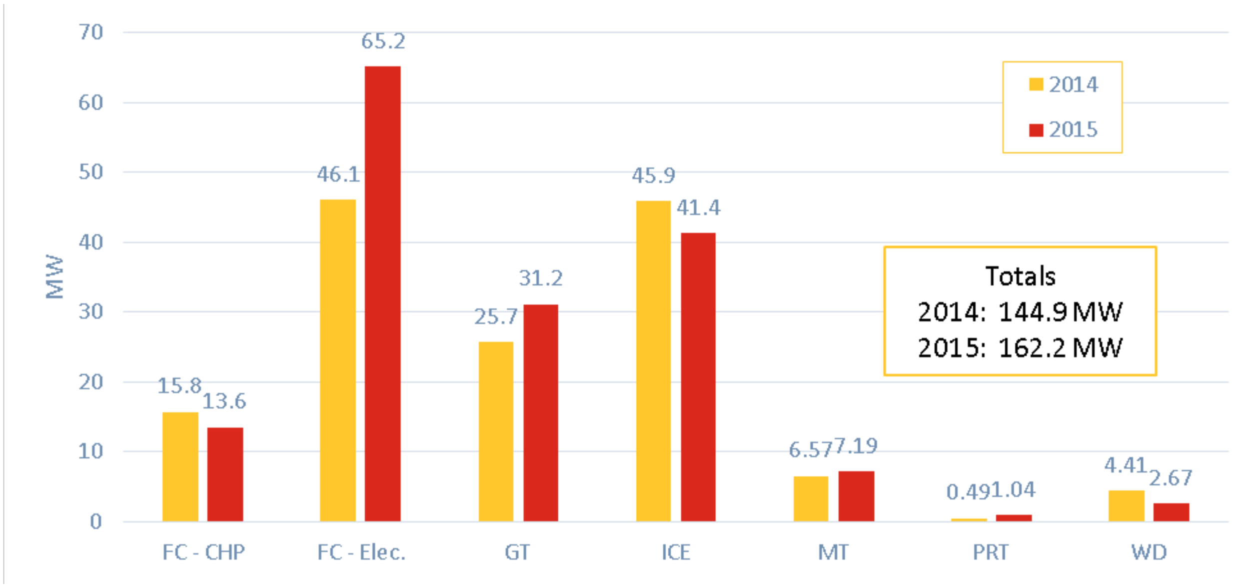
Year	2014			2015		
PA	PRE	POST	POST-SB 412 %	PRE	POST	POST-SB 412 %
CSE	17.0	2.02	11.9%	11.4	6.72	58.7%
PG&E	44.0	7.88	17.9%	37.6	30.5	81.1%
SCE	18.2	5.52	30.3%	16.1	13.6	84.2%
SCG	32.6	0.39	1.2%	26.9	1.20	4.4%
Total	**111.8**	**15.8**	**12.4%**	**92.1**	**52.0**	**36.1%**

Table 5-11 shows pre-SB 412 projects generated 111.8 MW during the 2014 CAISO peak. By 2015, pre-SB 412 project generation during the peak was down 17.5% to 92.1 MW. All PAs had declining contributions from pre-SB 412 projects. Pre-SB 412 projects nevertheless remain the larger contributor to CAISO peak generation.

Meanwhile post-SB 412 projects generated 15.8 MW and 52 MW in 2014 and 2015 respectively. This is an annual growth of 229%. Post-SB 412 contribution to peak hour generation went from 12.4% to 36.1% from 2014 to 2015. All PAs had increasing contributions from post-SB 412 projects.

Figure 5-9 shows 2014 and 2015 CAISO peak hour generation by technology.

Figure 5-9: 2014 and 2015 CAISO Peak Hour Generation by Technology



In 2014 and 2015, all-electric fuel cells led CAISO peak hour generation. Their lead over IC engines went from 0.2 MW to almost 24 MW from 2014 to 2015. Gas turbine generation increased by over 21% from 2014 to 2015. IC engine peak hour generation fell by 10% and CHP fuel cell by nearly 14% from 2014 to 2015.

Table 5-12 and Table 5-13 list CAISO peak hour generation by PA and technology for 2014 and 2015 respectively.

Table 5-12: 2014 CAISO Peak Hour Generation by PA and Technology (MW)

Technology Type	Fuel Cell - CHP	Fuel Cell - Electric Only	Gas Turbine	Internal Combustion Engine	Microturbine	Pressure Reduction Turbine	Wind	Total
CSE	4.92	3.53	9.22	0.71	0.18	0.45	0.00	**19.0**
PG&E	4.99	20.9	1.23	17.8	3.82	na	3.11	**51.8**
SCE	3.44	11.0	na	7.4	0.88	na	1.01	**23.7**
SCG	0.68	0.63	15.1	15.6	1.01	na	na	**33.0**
Total	**14.0**	**36.0**	**25.5**	**41.5**	**5.89**	**0.45**	**4.12**	**127.6**

Table 5-13: 2015 CAISO Peak Hour Generation by PA and Technology (MW)

Technology Type	Fuel Cell - CHP	Fuel Cell - Electric Only	Gas Turbine	Internal Combustion Engine	Microturbine	Pressure Reduction Turbine	Wind	Total
CSE	4.42	4.07	8.46	0.71	0.12	0.39	0.00	**18.2**
PG&E	4.18	30.3	6.40	19.2	5.14	0.00	2.99	**68.2**
SCE	3.16	14.8	na	9.76	1.28	na	0.69	**29.7**
SCG	2.20	0.63	12.2	12.2	0.88	na	na	**28.1**
Total	**14.0**	**49.8**	**27.1**	**41.9**	**7.42**	**0.39**	**3.68**	**144.2**

PG&E all-electric fuel cells generated the most during 2014 and 2015 CAISO peak hours, producing 20.9 MW and 30.3 MW respectively. PG&E IC engines followed in both years with 17.8 MW and 19.2 MW. SCG gas turbines and IC engines both generated over 15 MW in 2014 but then only 12.2 MW each in 2015. SCE all-electric fuel cells surpassed SCG gas turbines and IC engines in 2015. For CSE gas turbines were the biggest peak hour contributor in both years.

Microturbines made relatively small contributions to peak hour generation for all PAs. Wind and pressure reduction turbines also made minor contributions for those PAs that had any.

Figure 5-10 and Table 5-14 show 2014 and 2015 CAISO peak hour generation by PA and fuel category.

Figure 5-10: 2014 and 2015 CAISO Peak Hour Generation by PA and Fuel

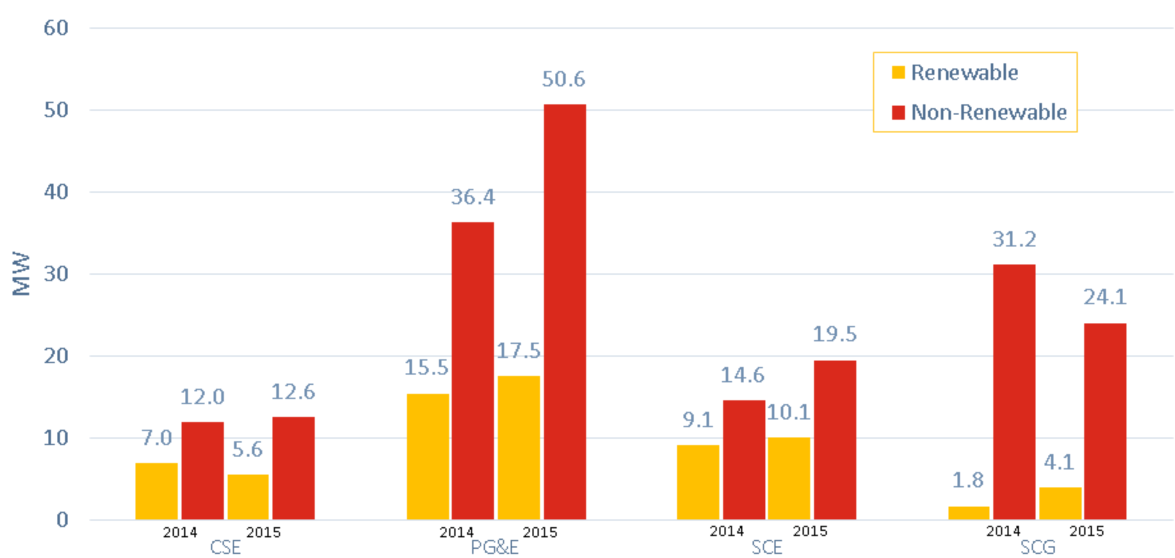


Table 5-14: 2014 and 2015 CAISO Peak Hour Generation by PA and Fuel (MW)

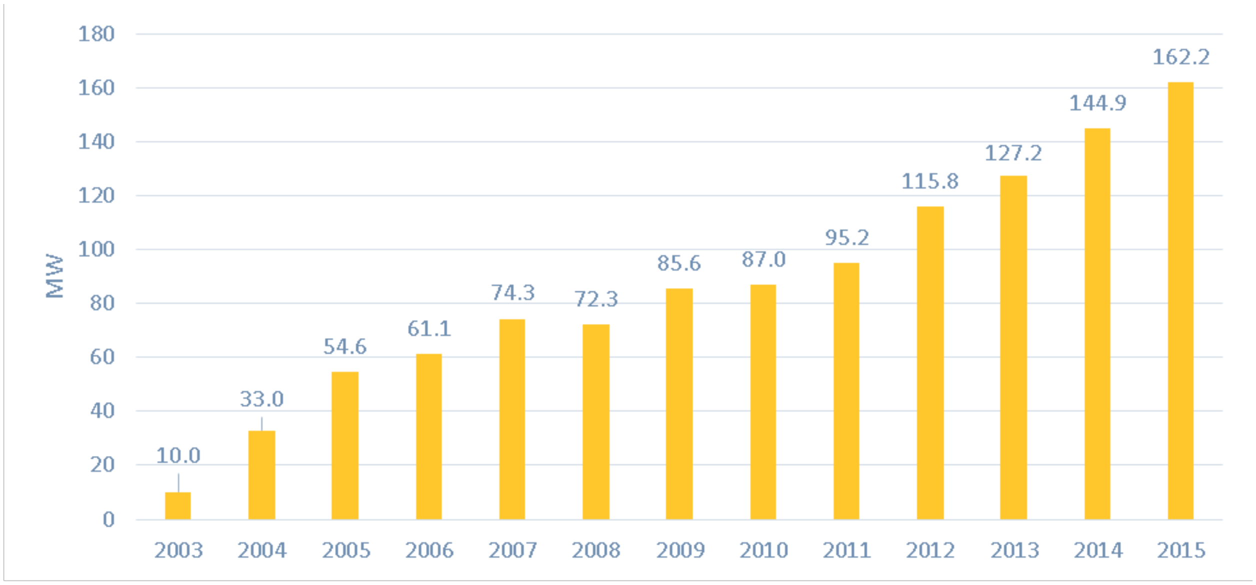
Year	2014			2015		
PA	Renewable	Non-Renewable	Renewable %	Renewable	Non-Renewable	Renewable %
CSE	7.00	12.0	36.8%	5.61	12.6	30.9%
PG&E	15.5	36.4	29.8%	17.5	50.6	25.7%
SCE	9.14	14.6	38.5%	10.1	19.5	34.2%
SCG	1.75	31.2	5.3%	4.06	24.1	14.4%
Total	**33.4**	**94.2**	**26.2%**	**37.4**	**106.8**	**25.9%**

Non-renewables continued as the main contributor to CAISO peak hour generation. Renewables contributed 33.4 MW and 37.1 MW in 2014 and 2015 respectively. Despite the increase, the renewable portion fell from 26.2% to 25.9% from 2014 to 2015 as the non-renewable component grew faster. The renewable contribution from CSE fell from 7.0 MW to 5.61 MW between 2014 and 2015 but rose for the other PAs.

CAISO Peak Hour Trends

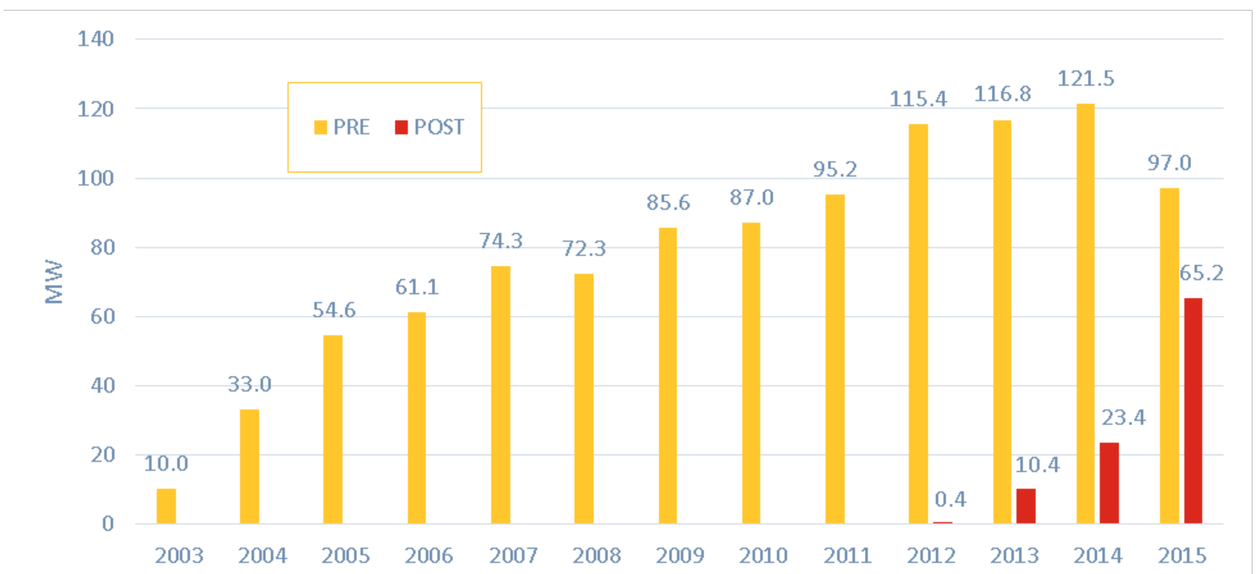
Over time, generation from SGIP projects coincident with the CAISO peak hour has grown. Contributions from various categories of projects have changed with addition of new and retirement of old projects. Figure 5-11 through Figure 5-14 show CAISO peak hour generation trends from 2003 to 2015 by key project categories.

Figure 5-11: CAISO Peak Hour Generation Total by Calendar Year



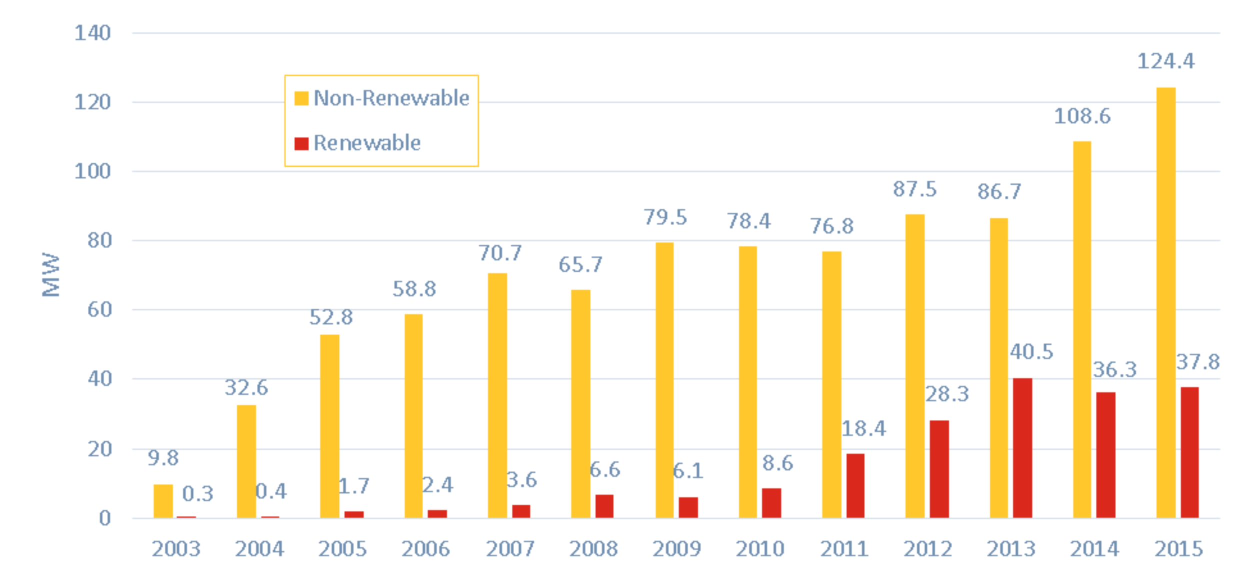
Growth in CAISO peak hour generation was steady except from 2008 to 2010. Rapid growth took place from 2011 to 2015.

Figure 5-12: CAISO Peak Hour Generation by SB 412 Pre/Post



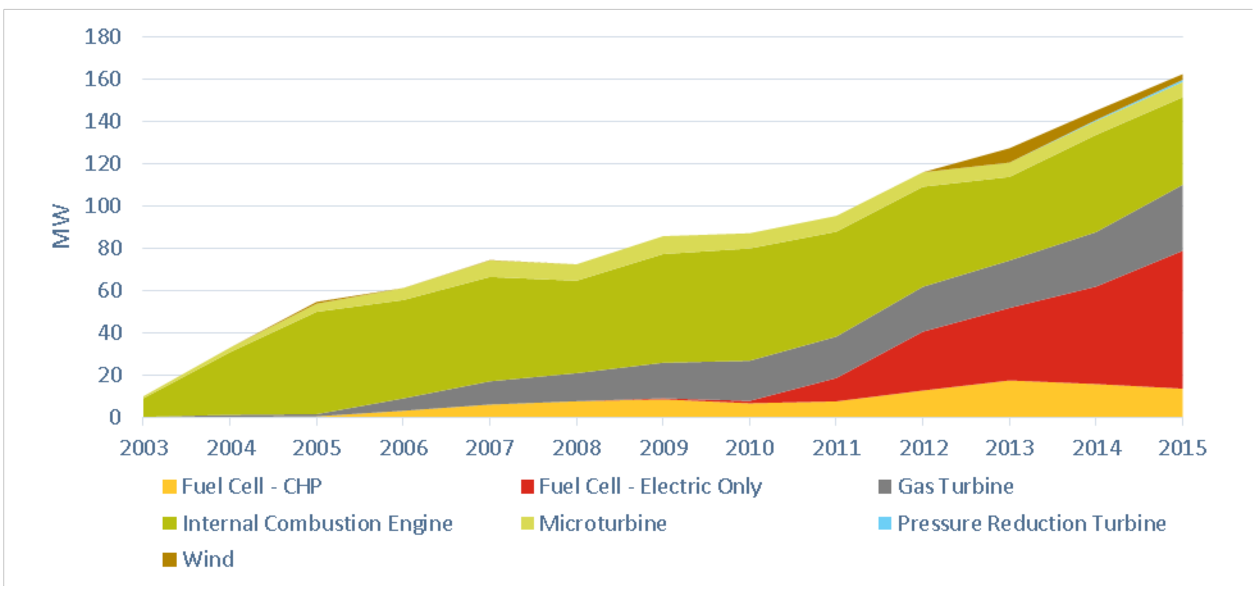
Post-SB 412 growth in CAISO peak hour generation has been very fast from 2014 to 2015.

Figure 5-13: CAISO Peak Hour Generation by Fuel



Renewable growth in CAISO peak hour generation stopped in 2014 and edged up slightly in 2015.

Figure 5-14: CAISO Peak Hour Generation by Technology



All-electric fuel cell growth in CAISO peak hour generation since 2010 has lifted program total into 2015. This growth is very similar to IC engine growth from 2002 to 2007. Since 2010, growth in other technologies has leveled off or declined into 2015.

Table 5-15: CAISO Peak Hour Generation by Technology (MW)

Technology Type	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Fuel Cell - CHP	0.20	0.20	0.51	3.12	6.09	7.growth	8.52	6.68	7.58	12.69	17.5	15.8	13.6
Fuel Cell - Electric Only							0.52	1.14	11.00	27.8	34.2	46.1	65.2
Gas Turbine		1.05	1.02	5.88	11.0	13.3	16.8	19.0	19.6	21.2	22.4	25.7	31.2
Internal Combustion Engine	8.85	29.6	48.3	46.5	49.3	43.7	51.4	53.0	49.6	47.2	39.5	45.9	41.4
Microturbine	0.97	2.17	3.87	5.62	7.82	7.75	8.42	7.18	7.43	6.86	6.78	6.57	7.19
Pressure Reduction Turbine												0.49	1.04
Wind			0.83	0.05	0.18						6.78	4.41	2.67
Total	**10.0**	**33.0**	**54.6**	**61.1**	**74.3**	**72.3**	**85.6**	**87.0**	**95.2**	**115.8**	**127.2**	**144.9**	**162.2**

CHP fuel cell CAISO peak hour generation reached 17.5 MW in 2013 but has fallen in 2014 and 2015. All-electric fuel cell peak hour generation nearly doubled from 2013 to 2015, reaching 65.2 MW. Gas turbine peak hour generation grew sharply in 2015 but still lags behind IC engines. IC engines meanwhile began declining in 2011, recovering in 2014 only to fall again in 2015. Microturbine peak hour generation has been relatively steady since 2007.

IOU Peak Hour

IOU Peak Hour Technology Totals 2014 and 2015

Generation coincident with the IOU annual peak hours in 2014 are shown in Table 5-16 and Figure 5-15 by Technology. Results for 2015 appear in Table 5-17 and Figure 5-16. Generation from SGIP systems is assigned to the IOU providing electrical service. For SoCalGas systems electrical service may be from a local municipal utility and so may not be associated with an IOU.

Figure 5-15: 2014 Peak Hour Generation by Technology

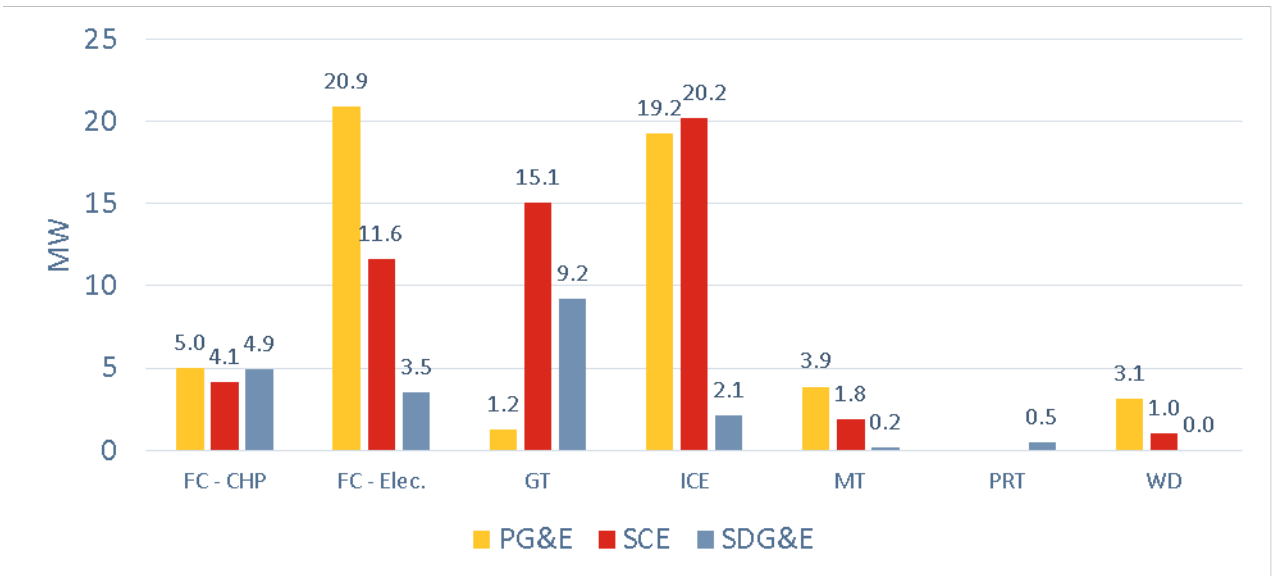


Table 5-16: 2014 IOU Peak Hour Generation by Technology (MW)

Technology Type	Fuel Cell - CHP	Fuel Cell - Electric Only	Gas Turbine	Internal Combustion Engine	Microturbine	Pressure Reduction Turbine	Wind	Total
PG&E	4.99	20.9	1.23	19.2	3.86	0.00	3.11	**53.3**
SCE	4.12	11.6	15.1	20.2	1.85		1.02	**53.8**
SDG&E	4.92	3.53	9.22	2.13	0.18	0.45	0.00	**20.4**

Peak hour generation from projects served by PG&E reached 53.3 MW during its 2014 peak hour. From projects served by SCE, peak hour generation was very similar at 53.8 MW during the SCE 2014 peak hour. For SDG&E, the 2014 peak hour generation was 20.4 MW.

All-electric fuel cells and IC engines made largest contributions for PG&E during its 2014 peak hour. For SCE, IC engines and gas turbines were top contributors with all-electric fuel cells following closely in 2014. For SDG&E, gas turbines were the top contributor during the 2014 peak hour and CHP fuel cells were a distant second.

Figure 5-16: 2015 Peak Hour Generation by Technology

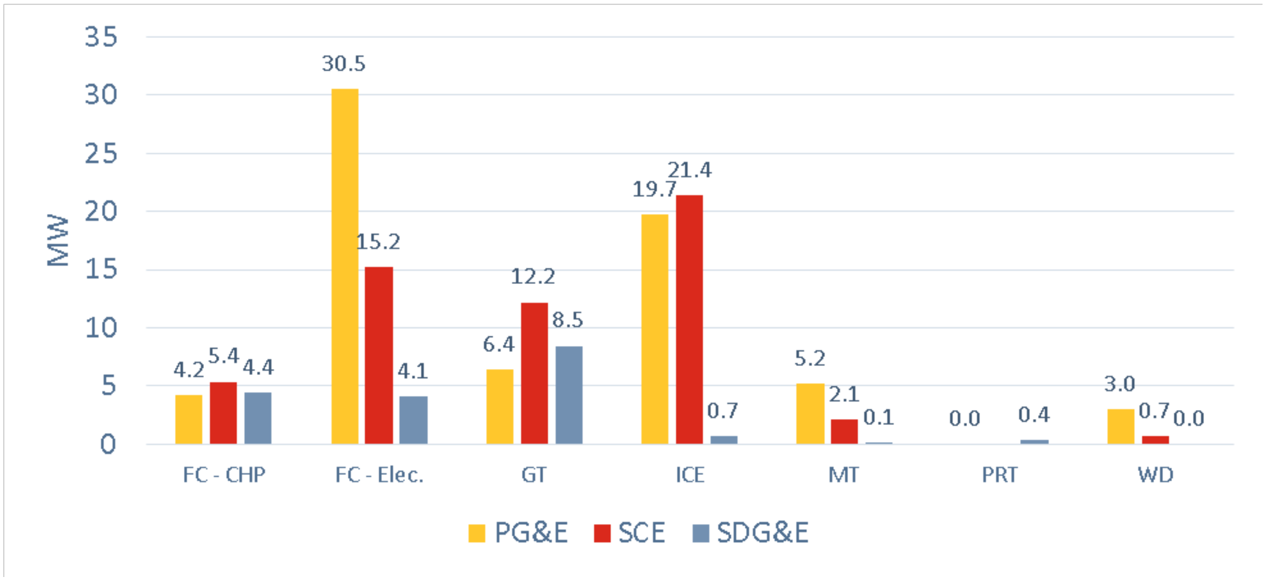


Table 5-17: 2015 IOU Peak Hour Generation by Technology (MW)

Technology Type	Fuel Cell - CHP	Fuel Cell - Electric Only	Gas Turbine	Internal Combustion Engine	Microturbine	Pressure Reduction Turbine	Wind	Total
PG&E	4.19	30.5	6.40	19.7	5.18	0.00	2.99	**69.0**
SCE	5.36	15.2	12.2	21.4	2.12		0.69	**57.0**
SDG&E	4.42	4.07	8.46	0.71	0.12	0.39	0.00	**18.2**

Peak hour generation from projects served by PG&E reached 69.0 MW during its 2015 peak hour. From projects served by SCE, peak hour generation reached 57.0 MW in 2015. For SDG&E, the 2015 peak hour dropped slightly from 20.4 MW in 2014 to 18.2 MW in 2015.

All-electric fuel cells and IC engines continued in 2015 to make largest contributions for PG&E during its 2015 peak hour. For SCE, IC engines continued as the top contributor in 2015 but all-electric fuel cells topped gas turbines for the first time. For SDG&E, gas turbines remained as the top contributor in during the 2015 peak hour. Meanwhile SDG&E saw a big increase from all-electric fuel cells, nearly matching generation from CHP fuel cells.

Both 2014 and 2015 IOU peak hour generation appear side-by-side by Technology in Figure 5-17, Figure 5-18, and Figure 5-19 for PG&E, SCE, and SDG&E respectively.

Figure 5-17: PG&E 2014 & 2015 Peak Hour Generation by Technology

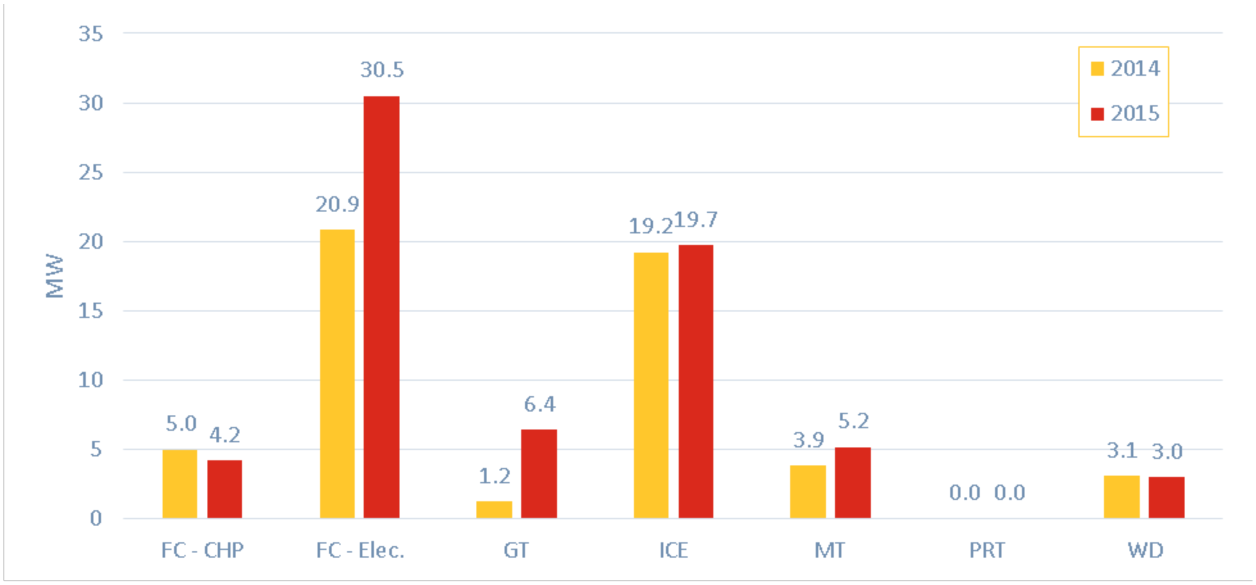


Figure 5-18: SCE 2014 & 2015 Peak Hour Generation by Technology

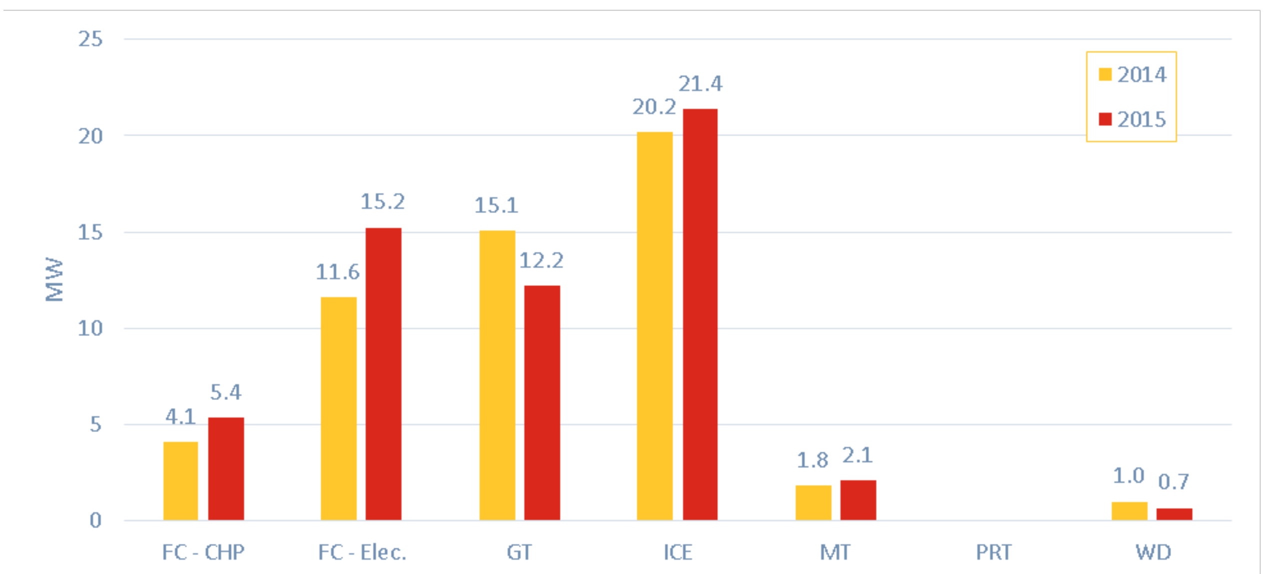
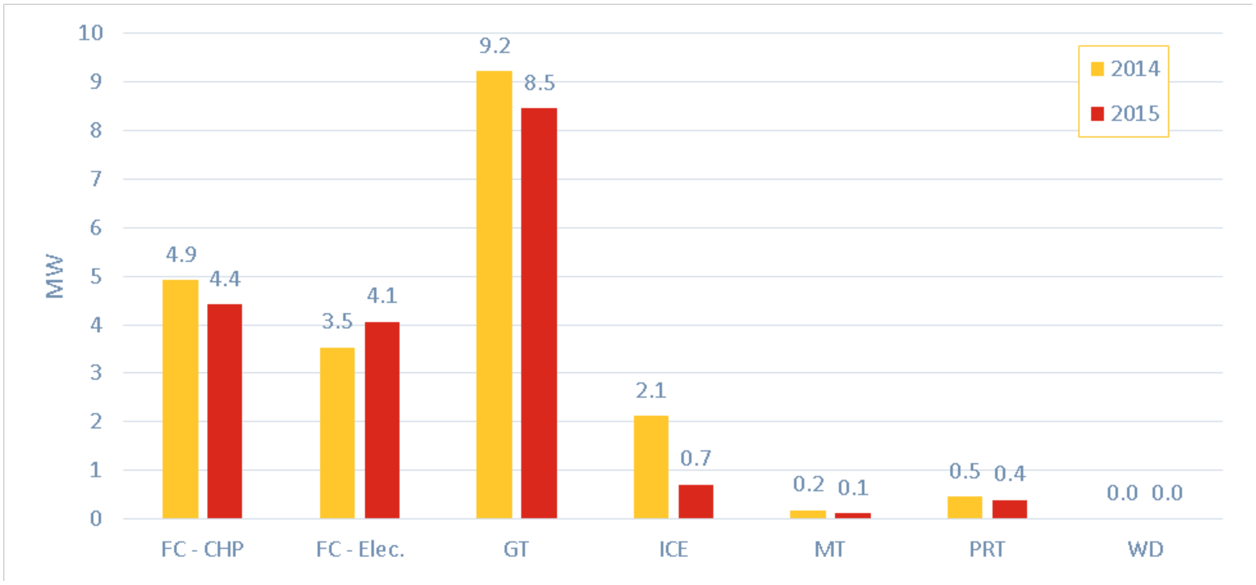


Figure 5-19: SDGE 2014 & 2015 Peak Hour Generation by Technology



IOU Peak Hour Trends

Over time, program generation coincident with IOU peak hours has grown. Contributions by various categories of projects have changed with addition of new and retirement of old capacity. In Appendix B, we show IOU peak hour generation from 2003 to 2015 in IOU plots like those for CAISO from Figure 5-11 to Figure 5-14.

Top 200 Peak Hours

CAISO and IOU annual peak hour coincident generation is a snapshot of beneficial program impacts. Here we examine a more robust measure of impacts by examining average generation coincident with the annual top 200 CAISO and IOU peak hours.

Representing just 2.3% of all hours in a year, the top 200 peak hours capture the steepest part of load distribution curves. Figure 5-20 shows 2015 CAISO and IOU load distribution curves and indicates the 200-hour mark.

Figure 5-20: 2015 CAISO and IOU Load Distribution Curves*

*Axes are scaled on left for CAISO and on right for the IOUs.

The distributions of top 200 hours over the courses of a year differs between CAISO and three IOUs and from year to year. While generally a mid-to-late summer weekday afternoon occurrence, a peak hour can occur on weekends and into October. Table 5-18 and Table 5-19 show distributions of top 200 peak hours for months and weekday types of 2014 and 2015 respectively.

Table 5-18: 2014 Top 200 Peak Hour Distributions by Month and Weekday

	May	June	July	August	September	October
CAISO	8	8	80	41	63	0
PG&E	4	31	104	40	21	0
SCE	13	0	63	45	79	0
SDG&E	17	0	36	33	109	5

	Saturdays	Sundays	Weekdays
CAISO	8	7	185
PG&E	7	10	183
SCE	9	8	183
SDG&E	9	16	175

Table 5-19: 2015 Top 200 Peak Hour Distributions by Month and Weekday

	May	June	July	August	September	October
CAISO	0	22	28	78	61	11
PG&E	0	46	67	49	38	0
SCE	0	6	10	88	74	22
SDG&E	0	0	0	70	86	45

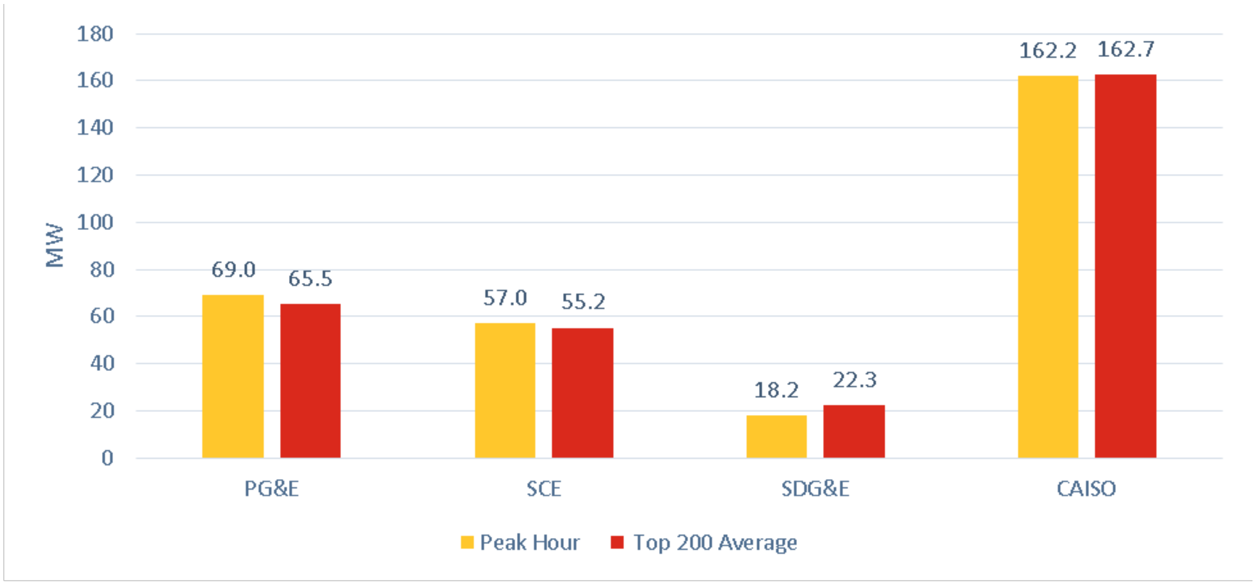
	Saturdays	Sundays	Weekdays
CAISO	10	12	178
PG&E	4	6	190
SCE	19	13	168
SDG&E	30	24	147

Top hours in 2014 began in May and were largely over by October. In contrast, 2015 top hours began in June and extended into October for SDG&E in particular. For PG&E, 2014 hours were primarily in July but 2015 hours were more evenly spread from June to September. For SCE, 2014 hours were spread from July to September while 2015 hours were mostly in August and September. For SDG&E, 2014 hours were dominated by September while 2015 hours were spread August to October.

For CAISO and all IOU, weekdays dominated top hours but weekends included some top hours in 2014 and 2015. For SDG&E, 27% of top hours in 2015 were on weekends.

Figure 5-21 shows total program generation coincident with the three IOU and CAISO 2015 peak hours alongside average program generation coincident with the 2015 top 200 peak hours.

Figure 5-21: 2015 CAISO and IOU Peak and Top 200 Peak Hour Generation by SGIP Projects



Peak hour and top 200 average generations in 2015 were within a few percent of each other except for SDG&E. The 2015 peak hour generation for SDG&E was well below the average of the top 200 hours.

CAISO peak hour and top 200 average generations appear by technology in Table 5-20 and Table 5-21 for 2014 and 2015 respectively. PG&E peak hour values for 2015 appear in Table 5-22; for SCE, in Table 5-23; and for SDG&E, in Table 5-24.

To compare peak hour values to averages across top 200 peak hours, tables below show percentages of average to peak hour generation for CAISO in 2014 and 2015 and for the IOUs in 2015. Most percentages are between 93% and 108%, indicating the peak hour is fairly robust measure itself of top 200 average.

Table 5-20: 2014 CAISO Peak Hour and Top 200 Average Demand Impacts (MW)

Technology Type	CAISO Peak Hour (MW)	CAISO Top 200 Average (MW)	Average to Peak
Fuel Cell - CHP	15.8	18.1	114.8%
Fuel Cell - Electric Only	46.1	45.3	98.4%
Gas Turbine	25.7	24.8	96.4%
Internal Combustion Engine	45.9	41.8	91.1%
Microturbine	6.6	6.3	95.2%
Pressure Reduction Turbine	0.49	0.43	87.5%
Wind	4.4	6.0	135.7%
Total	**144.9**	**142.7**	**98.5%**

Table 5-21: 2015 CAISO Peak Hour and Top 200 Average Demand Impacts (MW)

Technology Type	CAISO Peak Hour (MW)	CAISO Top 200 Average (MW)	Average to Peak
Fuel Cell - CHP	13.6	13.1	96.7%
Fuel Cell - Electric Only	65.2	62.4	95.7%
Gas Turbine	31.2	31.4	100.7%
Internal Combustion Engine	41.4	42.2	101.9%
Microturbine	7.2	7.8	108.5%
Pressure Reduction Turbine	1.04	0.80	77.2%
Wind	2.7	5.1	190.3%
Total	**162.2**	**162.7**	**100.3%**

Table 5-22: 2015 PG&E Peak Hour and Top 200 Average Demand Impacts (MW)

Technology Type	PGE Peak Hour (MW)	PGE Top 200 Average (MW)	Average to Peak
Fuel Cell - CHP	4.2	3.6	87%
Fuel Cell - Electric Only	31.0	23.5	76%
Gas Turbine	11.7	11.2	95%
Internal Combustion Engine	20.0	19.3	96%
Microturbine	5.1	4.9	97%
Pressure Reduction Turbine	0.0	0.3	
Wind	2.7	2.6	99%
Total	**75**	**65**	**88%**

Table 5-23: 2015 SCE Peak Hour and Top 200 Average Demand Impacts (MW)

Technology Type	SCE Peak Hour (MW)	SCE Top 200 Average (MW)	Average to Peak
Fuel Cell - CHP	5.36	2.83	52.9%
Fuel Cell - Electric Only	15.2	12.6	82.7%
Gas Turbine	12.2	13.7	112.3%
Internal Combustion Engine	21.4	21.8	101.9%
Microturbine	2.12	2.28	107.4%
Pressure Reduction Turbine	na	na	na
Wind	0.69	1.99	289.0%
Total	**57.0**	**55.2**	**96.8%**

Table 5-24: 2015 SDG&E Peak Hour and Top 200 Average Demand Impacts (MW)

Technology Type	SDGE Peak Hour (MW)	SDGE Top 200 Average (MW)	Average to Peak
Fuel Cell - CHP	4.42	4.15	93.8%
Fuel Cell - Electric Only	4.07	4.74	116.6%
Gas Turbine	8.46	11.3	134.0%
Internal Combustion Engine	0.71	1.4	196.7%
Microturbine	0.12	0.04	38.9%
Pressure Reduction Turbine	0.39	0.41	104.6%
Wind	0.00	0.21	
Total	**18.2**	**22.3**	**122.7%**

Noncoincident Customer Peak Demand Impacts

SGIP projects impact customer demand in addition to system (IOU or CAISO) peak demand. It is rare that any particular customer's annual peak demand falls on the CAISO or IOU peak hour. The peak customer demand during any stated period is call Noncoincident Peak (NCP) customer demand. This aggregated noncoincident peak is the value that NEM totals are based on and the aggregate noncoincident peak is two to three times the coincident peak demand for IOUs in California.[8] The first metric this sub-section looks at is the impact on customer's annual peak demand, which is important for understanding, the total reduction SGIP has on customer loads.

The demand portion of customer bills is based on the monthly peak kW. Thus, in addition to the reduction in annual peak demand, the monthly demand reduction illustrates how SGIP impacts customer energy costs.

Approach for Noncoincident Customer Peak Demand Impacts

To analyze the impact of SGIP on NCP customer demand, we first aligned the available load and generation data on an hourly basis. We then calculated what the gross demand would have been without the presence of the SGIP generation as the following[9]:

$$Gross\ Load\ (\overline{kW}) = Metered\ Load\ (\overline{kW}) + Generation\ (\overline{kW})$$

$$Net\ Load\ (\overline{kW}) = Metered\ Load\ (\overline{kW})$$

[8] http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=4692

[9] For this analysis, demand is calculated as the average power draw within a one-hour period. This is an approximate calculation, as demand is measured in 15-minute intervals and may differ from the hourly average.

The potential impact of SGIP generators on gross and net load can be seen graphically in the following figures. Figure 5-22 shows an example of how metered NCP customer demand, represented by net load, is reduced by SGIP generation. Figure 5-23 illustrates the impact an SGIP generator outage has on NCP customer demand. Depending on the customer load profile, a generator outage can likely set the monthly or annual peak demand.

Figure 5-22: Demand Impact from Generator with Consistent Output

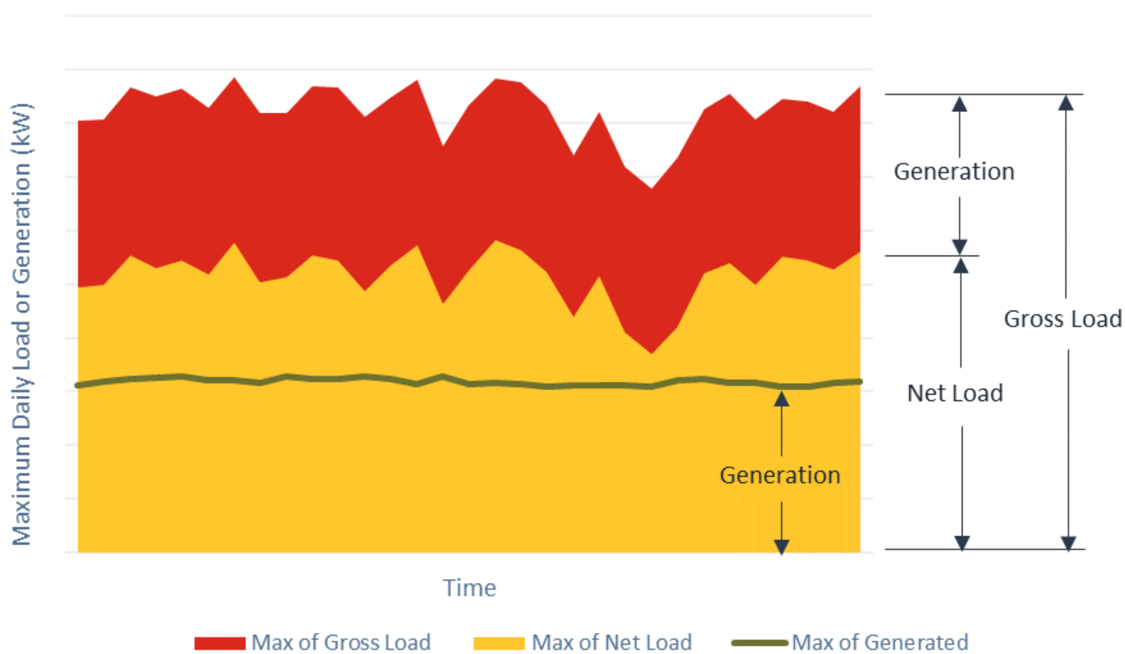
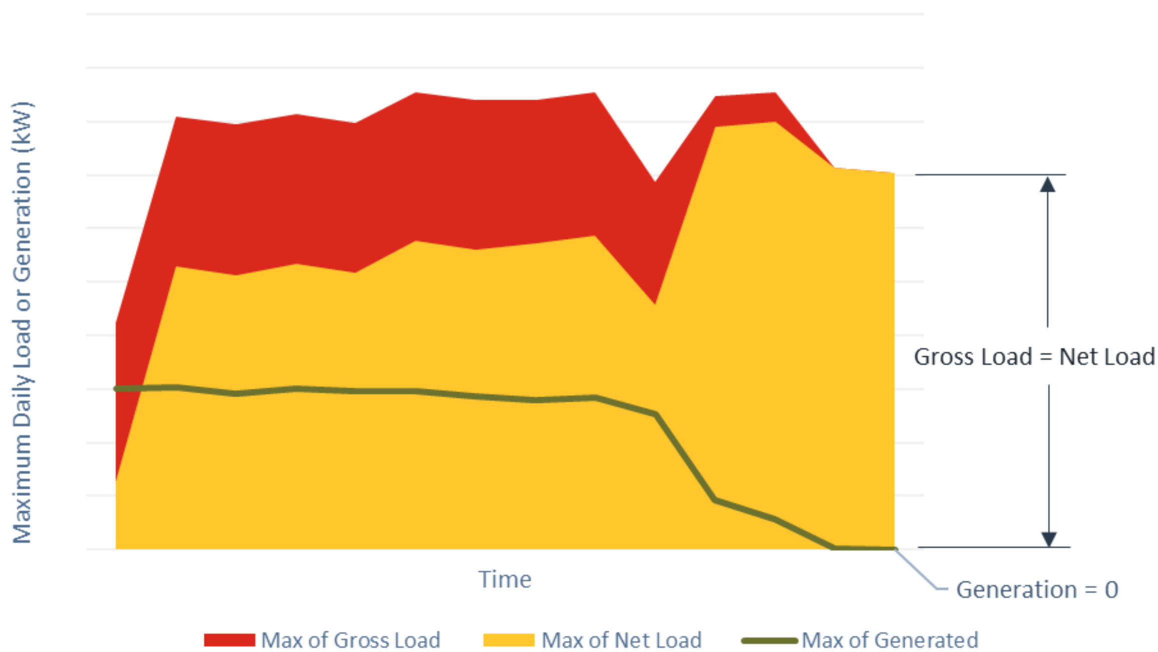


Figure 5-23: Demand Impact from Generator with Outage



On a monthly basis, the impact of SGIP generation on demand is then approximately above:

$$Max\left[Gross\ Load\ (\overline{kW})\right]_{month} - Max\left[Net\ Load\ (\overline{kW})\right]_{month}$$

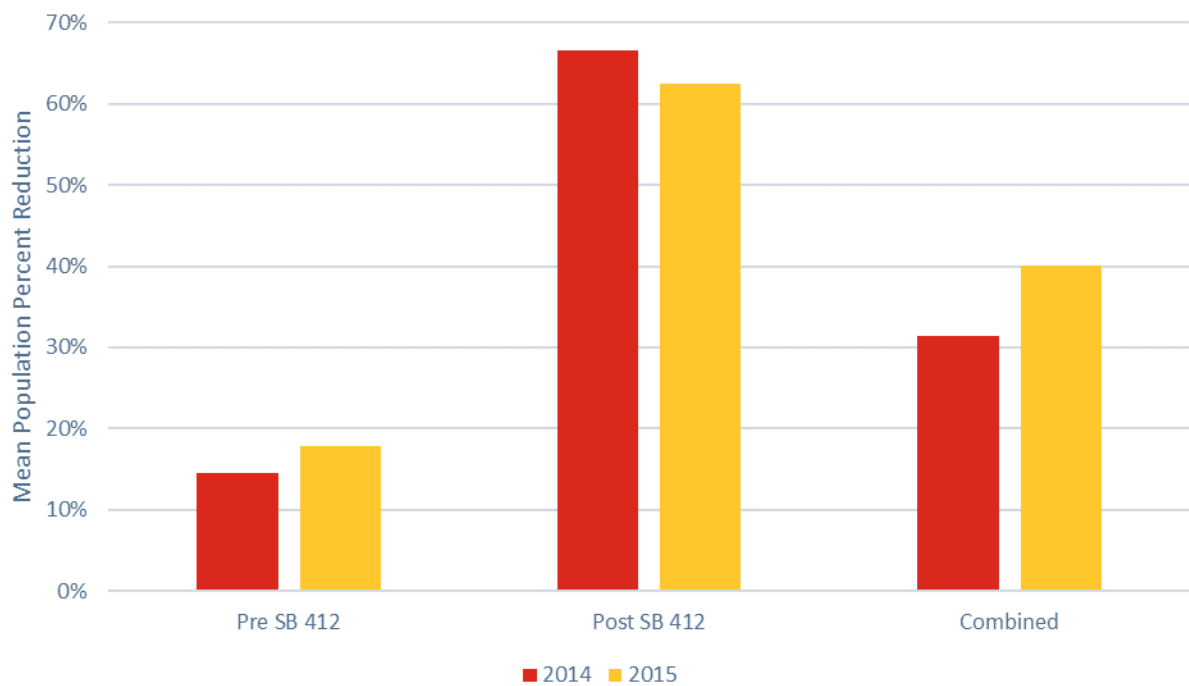
and annually:

$$Max\left[Gross\ Load\ (\overline{kW})\right]_{year} - Max\left[Net\ Load\ (\overline{kW})\right]_{year}$$

Annual NCP Customer Demand Impacts

The average demand impacts of non-AES technologies on NCP customer demand are shown in Figure 5-24 as a fraction of rebated capacity. For instance, projects Post-SB 412 delivered demand savings over 60 percent of their capacity; so a 1 MW project would, on average, reduce NCP customer demand by over 600 kW. Pre-SB 412 projects show substantially lower demand reductions, in part due to these being older systems and therefore more likely to be offline or decommissioned.

Figure 5-24: Annual NCP Customer Demand Impacts for the Population



The average reduction across the population was slightly more than 30 percent of installed capacity in 2014 and slightly less than 40 percent in 2015. Although this appears to be a change, it is not statistically significant. The differences between Pre-SB 412 and Post-SB 412, however, are likely significant. Data was unavailable for SDG&E projects, as well as gas turbines, and thus excluded from this demand impact analysis.

Annual NCP Customer Demand Impacts by Technology

Different technologies appear to have significantly different impacts on annual NCP customer demand. Figure 5-25 and Figure 5-26 show the average demand impact as a percent of rebated capacity for different technologies and SB 412 status for 2014 and 2015, respectively.

Figure 5-25: Annual 2014 NCP Customer Demand Reduction

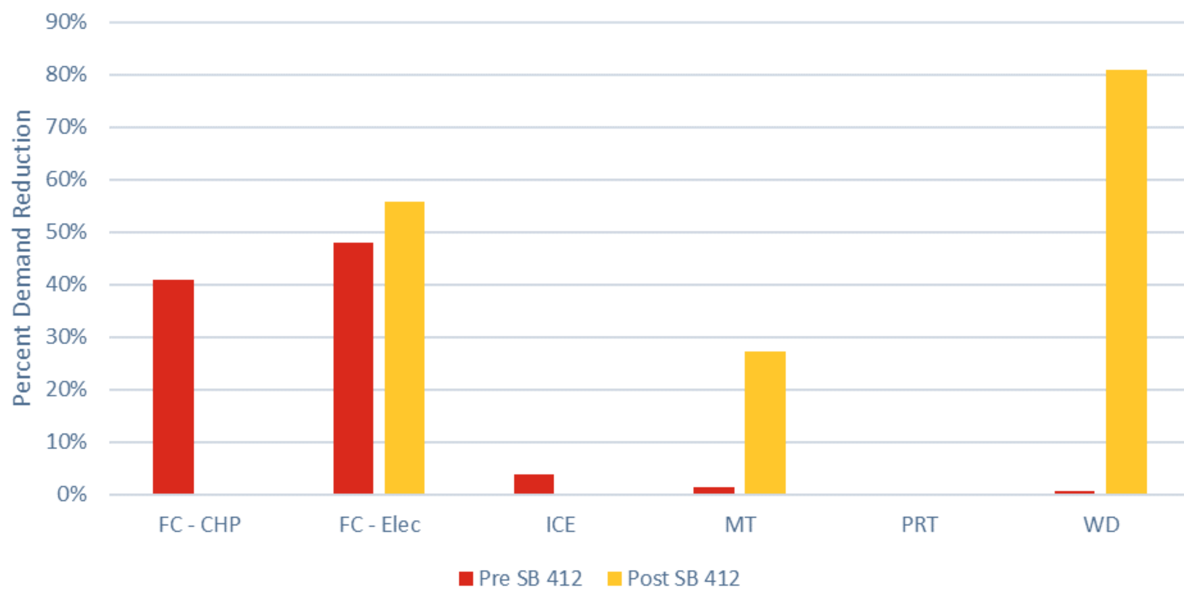
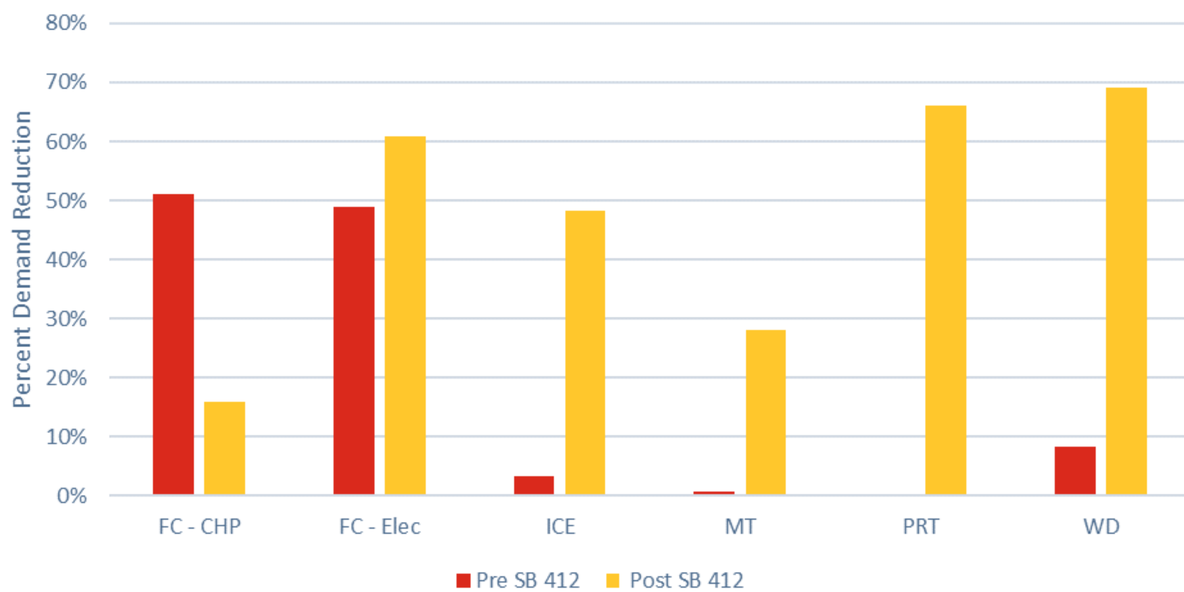
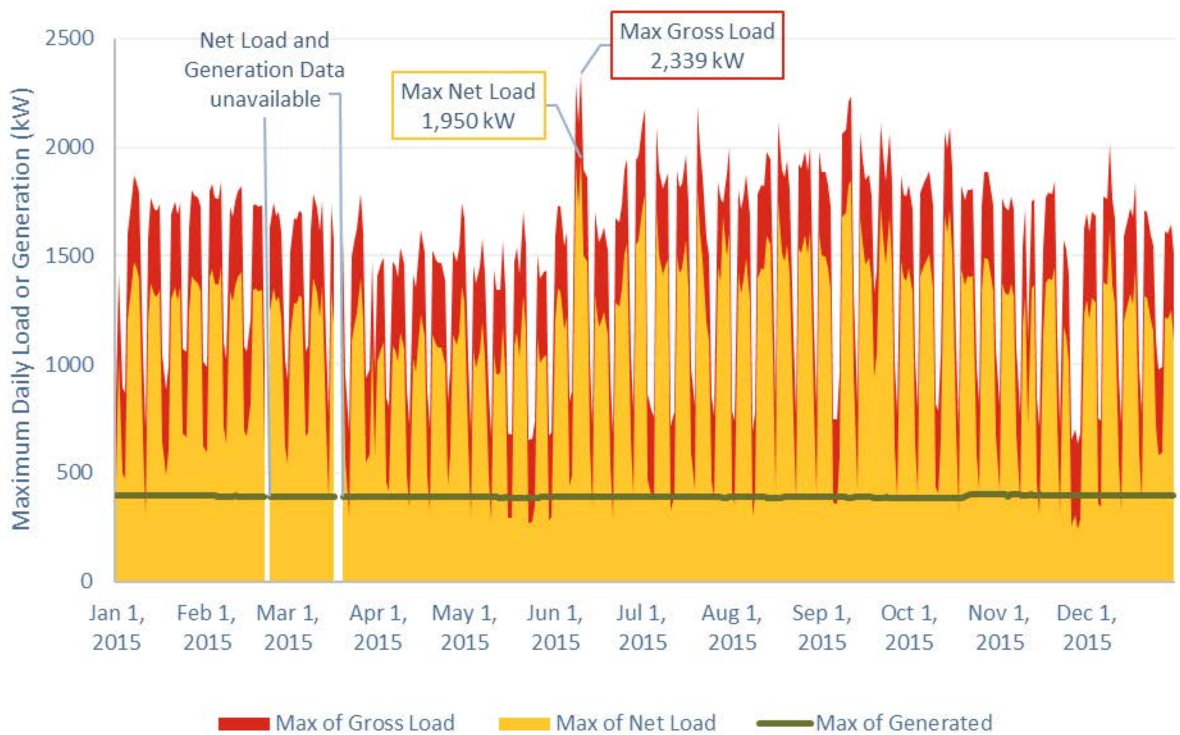


Figure 5-26: Annual 2015 NCP Customer Demand Reduction



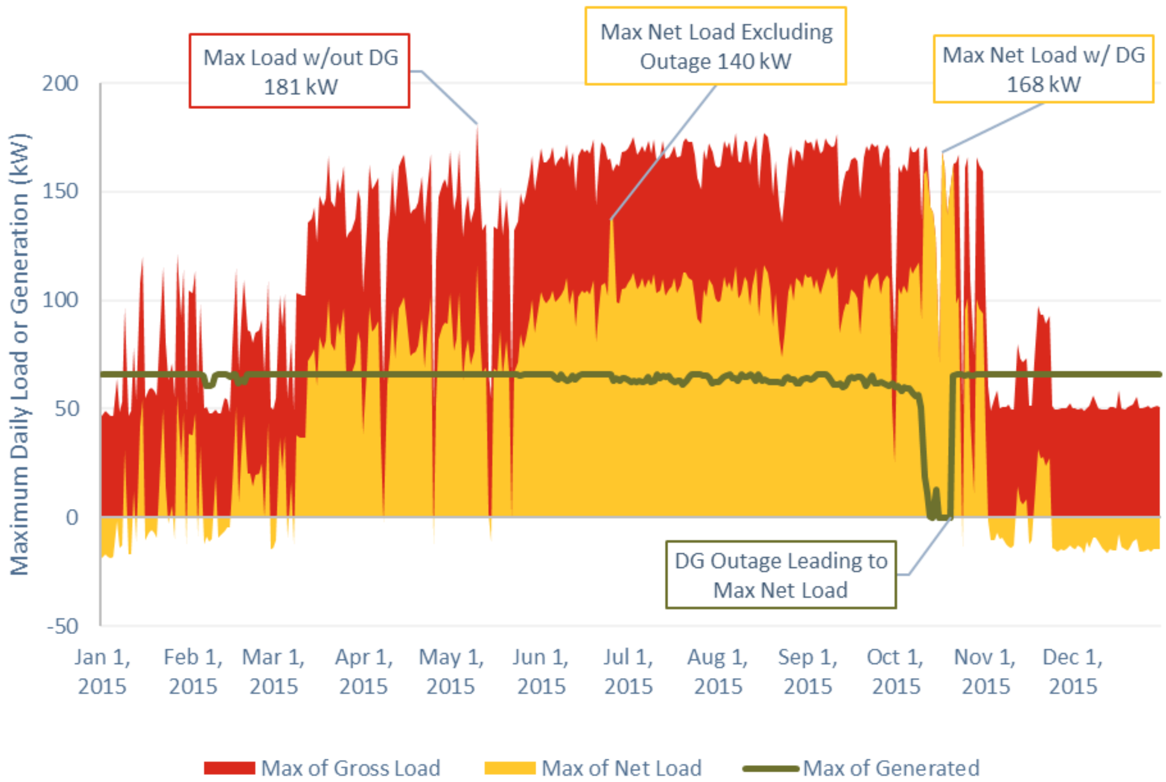
As seen at the program level, post-SB 412 projects exhibited higher demand impacts than pre-SB 412 projects. One exception is Fuel Cell CHP but the sample size is small and the low average is due to a two of the four post-SB 412 projects being offline during peak customer demand. On a technology level, ECE fuel cells showed the highest fraction of customer demand reduction, especially post-SB 412. This is largely a result of consistent operation and few outages as shown in Figure 5-27. Pressure reduction turbines and wind projects also exhibited high demand savings post-SB 412, but with very small sample sizes, any conclusions should be drawn carefully.

Figure 5-27: Post-SB412 ECE Fuel Cell with Consistent Operation and Therefore Significant Demand Reduction



The fuel cell in Figure 5-27 operated consistently through the year so was able to reduce annual peak demand from 2,339 kW to 1,950 kW (389 kW peak demand reduction). Conversely, Figure 5-28 shows a microturbine that operated consistently for much of the year but was offline in late October / early November, resulting in an annual peak load reduction of only 13 kW (181 kW – 168 kW). If the generator had not been offline or if the offline period could have been better timed (like during the low load period in December), the load reduction might have been as great as 41 kW (181 kW - 140 kW). However, despite a relatively low annual peak demand reduction, this project had consistent monthly demand reductions outside of October and November.

Figure 5-28: Microturbine with Partial Outage



Average Monthly NCP Customer Demand Reductions

Reduction to annual NCP customer demand is one metric to measure the demand savings of SGIP that aligns with some policy decisions (NEM and AB 162 (Gordon/Skinner)). Another useful metric that is relevant to host customers is average monthly demand reduction since demand charges are billed on a monthly basis. Figure 5-29 and Figure 5-30 show the average monthly demand reduction for 2014 and 2015, respectively.

Figure 5-29: 2014 Average Monthly NCP Customer Demand Reduction

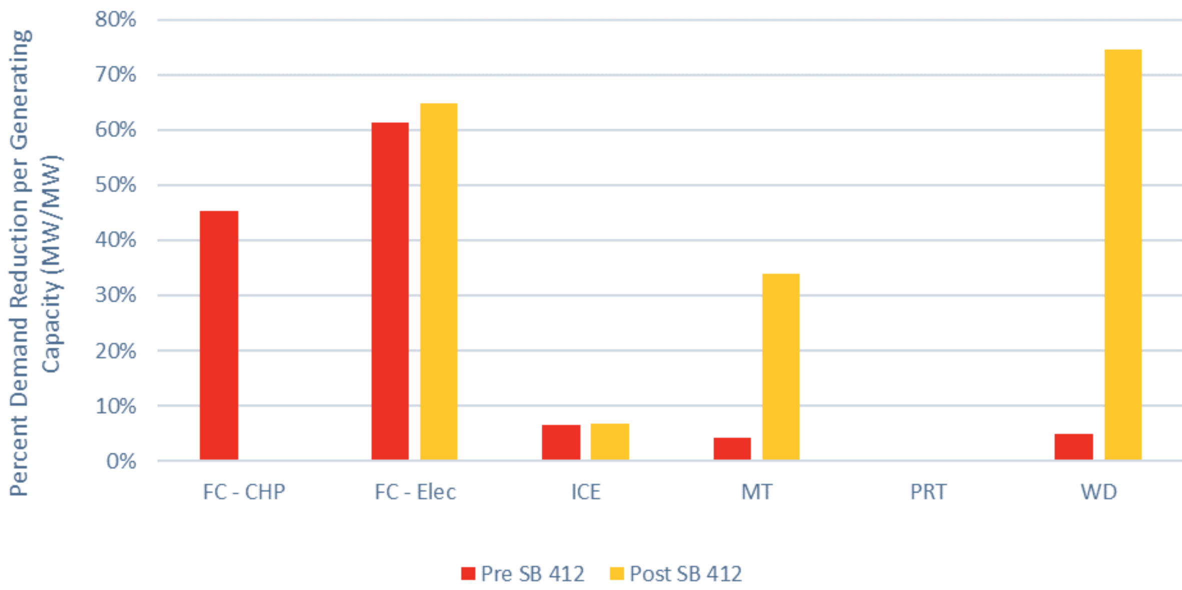
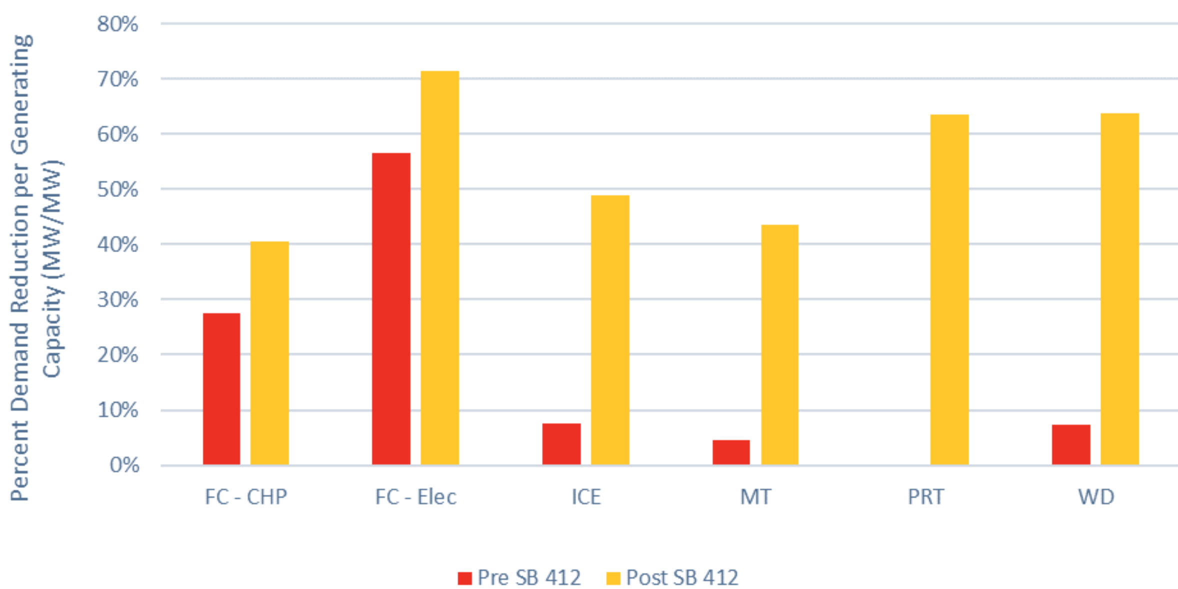


Figure 5-30: 2015 Average Monthly NCP Customer Demand Reduction



The results for average monthly demand reductions are similar to the annual demand reductions. However, CHP fuel cells, IC engines, and micro turbines show higher post-SB 412 monthly average reductions vs. annual peak reductions. This is likely a result of partial outages driving a net load peak similar to that seen in Figure 5-28.

5.3 Utilization and Capacity Factors

Energy impacts are a function of generating capacity and utilization. Capacity factor is a metric of system utilization. Capacity factor is defined as the amount of energy generated during a given time period divided by the maximum possible amount of energy that could have been generated during that time period. A high capacity factor (near one) for a period indicates that the system is being utilized to its maximum potential.

Host customers generate at capacity factors according to their individual needs. Some only need full capacity during weekday afternoons; others need full capacity 24/7. Annual capacity factors are useful when comparing utilization between or across varieties of project sizes and technologies. To the extent that SGIP projects are cleaner (with respect to greenhouse gases and criteria air pollutants) than the grid energy they displace, high annual capacity factors are desirable. A capacity factor of 1.0 is full utilization regardless of a project's generating capacity.

The annual capacity factor of a project, CF_a, is defined in Equation 5-1 as the sum of hourly electric net generation output, $ENGO_h$, during all 8,760 hours of the year divided by the product of the project's capacity and 8,760. If a project was completed mid-year, then the annual capacity factor is evaluated from the completion date through the end of year.

$$CF_a = \frac{\sum_{h=1}^{8,760} ENGO_h\,(kWh)}{Capacity\,(kw) \cdot 8,760\,(hr)}$$

Equation 5-1

Figure 5-31 shows annual capacity factors for seven program technology populations in 2014 and 2015.

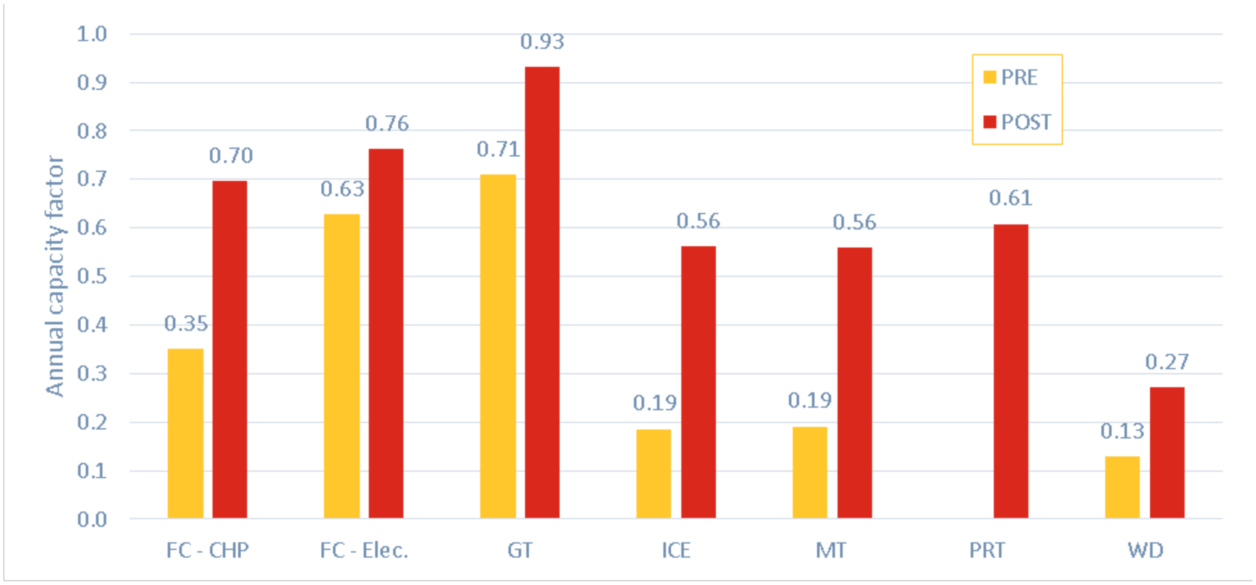
Figure 5-31: 2014 and 2015 Annual Capacity Factors by Technology

Gas turbines had the highest annual capacity factors in both 2014 and 2015. All-electric fuel cells followed closely behind gas turbines. Capacity factors for both technologies were remarkably similar year to year.

Pressure reduction turbines followed very closely behind all-electric fuel cells in 2014, but then declined in 2015. Wind, IC engines, and microturbines all had capacity factors below 0.25 in 2014 and 2015. CHP fuel cells also had a declining capacity factor from 2014 to 2015.

Figure 5-32 shows annual capacity factors for seven program technologies by pre-SB 412 and post-SB 412 in 2015.

Figure 5-32: 2015 Annual Capacity Factors by Technology and SB 412 Pre/Post



In 2015, all technologies had higher annual capacity factors from their post-SB 412 projects than from their pre-SB 412 counterparts. IC engine and microturbine capacity factors were substantially greater for post-SB 412 projects in part because pre-SB 412 capacity factors here include many more retired projects. Gas turbines had highest pre-and post-SB 412 capacity factors. Post-SB 412 all-electric fuel cells in 2015 had greater capacity factors than pre-SB 412 gas turbines.

Differences in annual capacity factors between pre-SB 412 and post-SB 412 technologies are due in part to many pre-SB 412 projects being retired by their hosts and having capacity factors of zero. Post-SB 412 projects, on the other hand, are mostly under 5 years old and in active use. To reduce the influences of retirement, we classified projects as active in a year if 10 or more monthly capacity factors exceeded a minimum threshold of 0.1. Figure 5-33~~Figure 5-33~~ compares 2015 annual capacity factors between pre- and post-SB 412 projects among active systems.

Figure 5-33: 2014 and 2015 Annual Capacity Factors of Active Projects by Technology and SB 412 Pre/Post

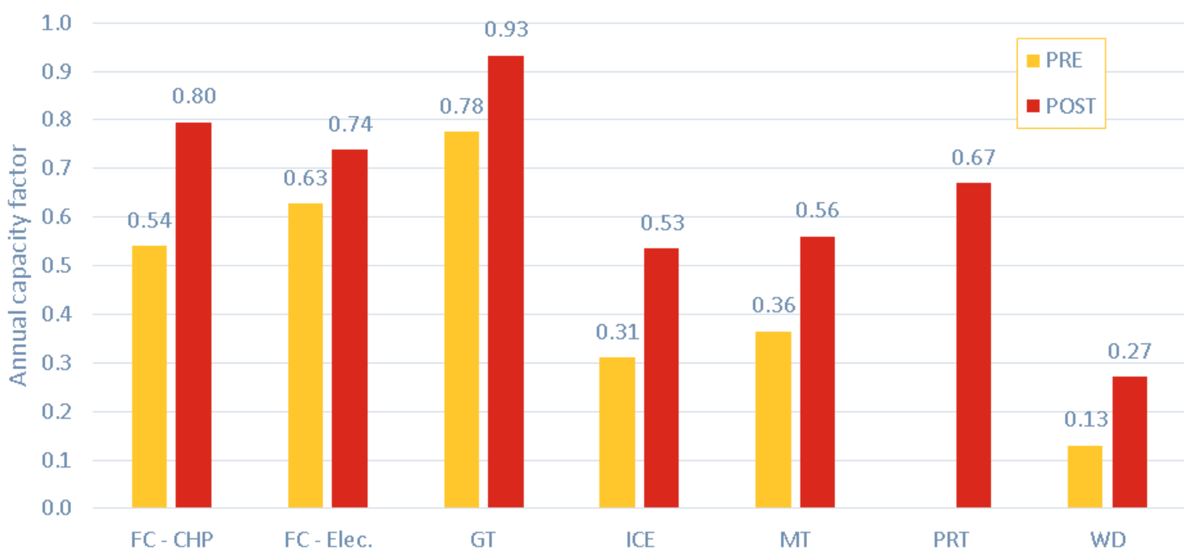
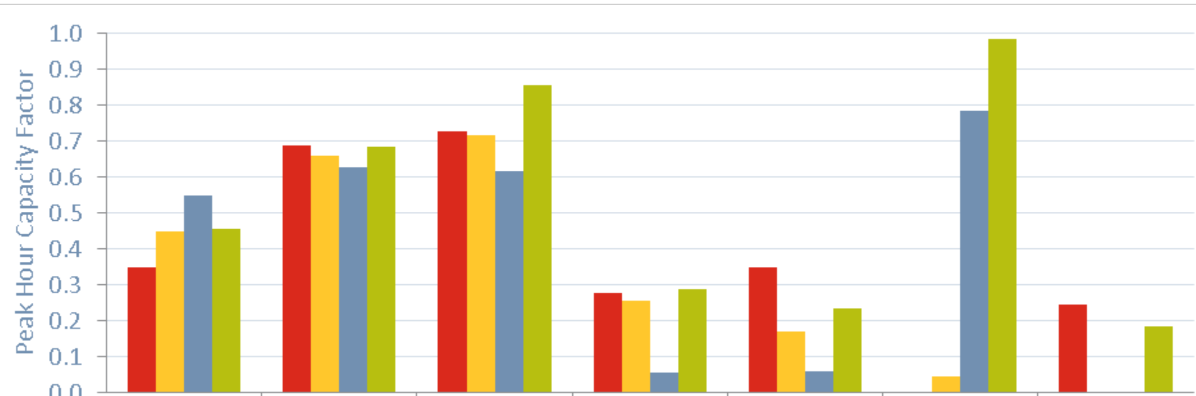


Figure 5-33~~Figure 5-33~~ shows that 2015 annual capacity factors among active pre-SB 412 projects still lag their active post-SB 412 counterparts. Relative to Figure 5-32, it also shows the influence of retirement on pre-SB 412 capacity factor in 2015. Pre-SB 412 capacity factor of all-electric fuel cells shows no change from Figure 5-32 to Figure 5-33~~Figure 5-33~~. This indicates retirement has yet to influence pre-SB 412 projects with that technology.

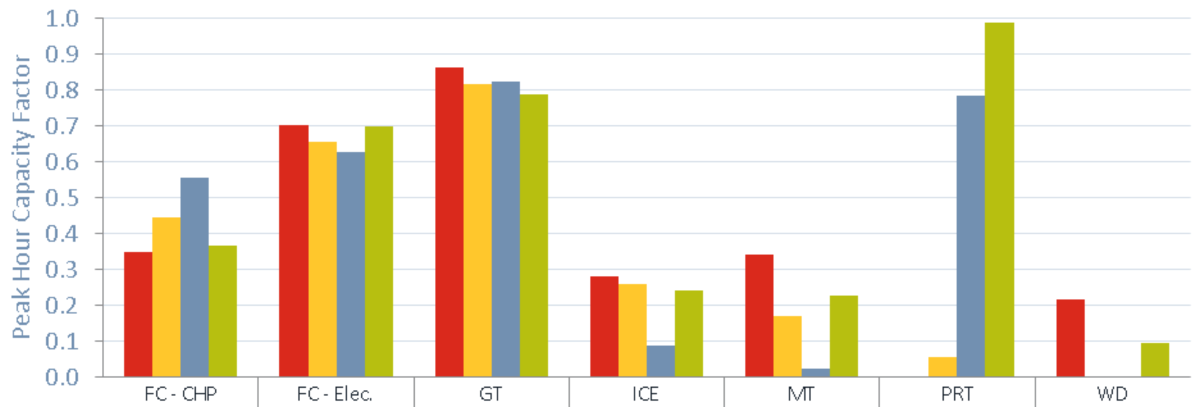
Higher utilization coincident with CAISO and IOU peak hours yields higher benefits to the grid than during other hours. The capacity factors for each technology during CAISO and IOU annual peak hours are shown by PA in Figure 5-34 and Figure 5-35 for 2014 and 2015 respectively

Figure 5-34: 2014 CAISO and IOU Peak Hour Capacity Factors by Technology



	FC - CHP	FC - Elec.	GT	ICE	MT	PRT	WD
PG&E	0.35	0.69	0.73	0.28	0.35		0.24
SCE	0.45	0.66	0.72	0.26	0.17	0.05	
SDG&E	0.55	0.63	0.62	0.06	0.06	0.79	
CAISO	0.46	0.68	0.85	0.29	0.24	0.99	0.19

Figure 5-35: 2015 CAISO and IOU Peak Hour Capacity Factors by Technology



	FC - CHP	FC - Elec.	GT	ICE	MT	PRT	WD
PG&E	0.35	0.70	0.86	0.28	0.34		0.22
SCE	0.45	0.66	0.82	0.26	0.17	0.06	
SDG&E	0.55	0.63	0.82	0.09	0.02	0.78	
CAISO	0.37	0.70	0.79	0.24	0.23	0.99	0.09

Gas turbines had high capacity factors for CAISO and IOU peak hours in 2014 and 2015. They were all near 0.8 in 2015. All-electric fuel cells likewise had high capacity factors for CAISO and IOU peak hours in 2014 and 2015. Pressure reduction turbines delivered very high capacity factors for CAISO in both 2014 and 2015 and capacity factors on par with gas turbines for SDG&E in both years. IC engine capacity factors differed little from 2014 to 2015.

5.4 System Efficiencies

The ability to convert fuel into useful electrical and thermal energy is measured by the system's combined efficiency in doing both. The combined or overall system efficiency is defined in Equation 5-2 as the ratio of the sum of electrical generation and useful recovered heat[10] to the fuel energy input.

$$\eta_{system} = \frac{ENGO_{kWh} \cdot 3.412 + HEAT_{MBtu}}{FUEL_{MBtu,\,LHV}}$$

Equation 5-2

The higher the system's overall efficiency the less fuel input is required to produce the sum of electricity and useful recovered heat. Electric-only fuel cells do not require useful heat recovery capabilities; therefore, their system overall efficiency has only an electrical component. Technologies that recover useful heat have electrical and thermal component efficiencies. All efficiencies are reported on a lower heating value (LHV) basis.[11] System overall and component efficiencies observed for non-renewable

[10] In the context of this report, useful heat is defined as heat that is recovered from CHP projects and used to serve on-site thermal loads. Waste heat that is lost to the atmosphere or dumped via radiators is not considered useful heat.

[11] This evaluation report assumes a natural gas lower heating value energy content of 934.9 Btu/SCF and higher heating content of 1036.6 Btu/SCF for an LHV/HHV ratio of 0.9019 (Combined Heating, Cooling & Power Handbook: Technologies & Applications. Neil Petchers. The Fairmont Press, 2003.)

projects in 2014 and 2015 are shown in Figure 5-36 and Figure 5-37 respectively. Both figures include dotted reference lines based on program minimum overall efficiency targets of 60% HHV (54.1% LHV) for CHP and 40% HHV (36.1% LHV) for all-electric fuel cells.

Figure 5-36: 2014 Overall and Component LHV Efficiencies by Technology

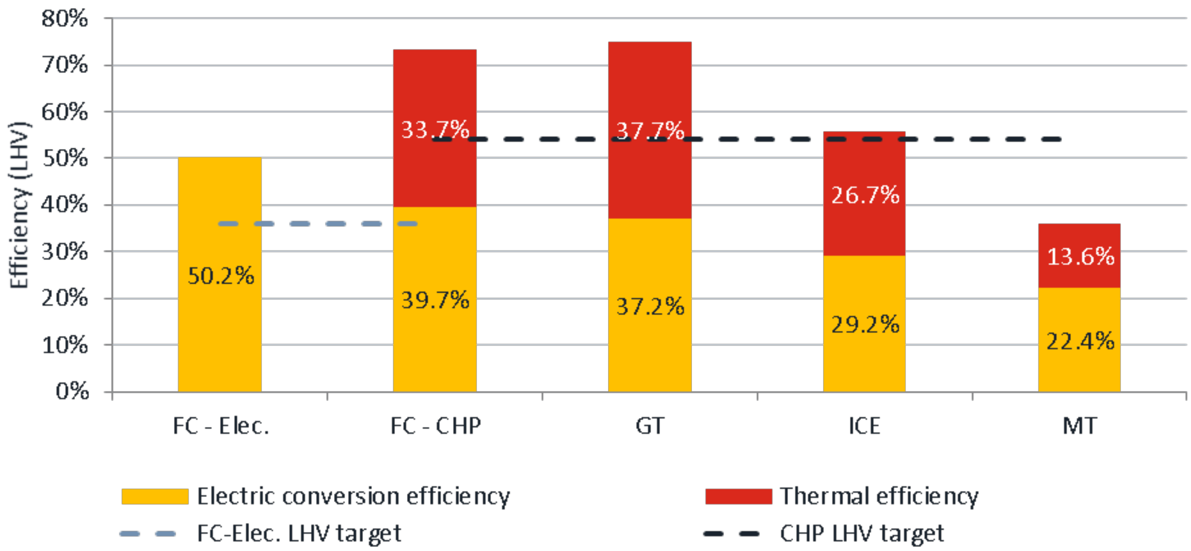
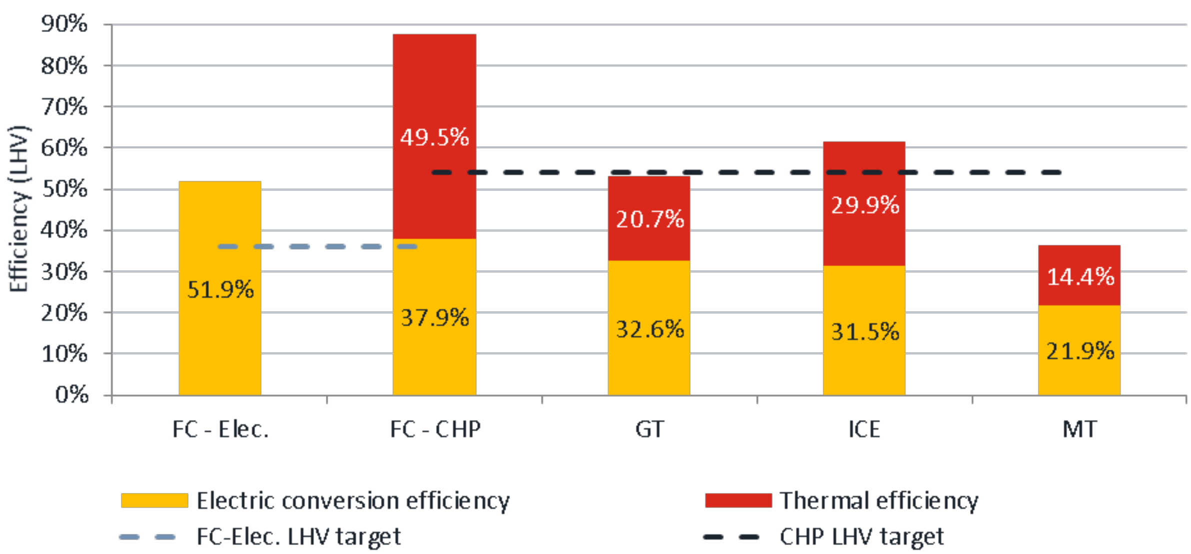


Figure 5-37: 2015 Overall and Component LHV Efficiencies by Technology



Electric conversion efficiencies of technologies are expected to improve over time. Post-SB 412 projects then might be expected to display somewhat greater electric conversions efficiencies than pre-SB 412 projects. Useful heat recovery efficiencies also may be expected to improve over time, but are more sensitive than electric conversion efficiencies to the particular thermal needs of a site. Figure 5-38~~Figure~~

5-38 and Figure 5-39~~Figure 5-39~~ show the overall and component LHV efficiencies of pre-and post-SB 412 projects for 2014 and 2015 respectively.

Figure 5-38: 2014 Overall and Component LHV Efficiencies by Technology and SB 412 Pre/Post

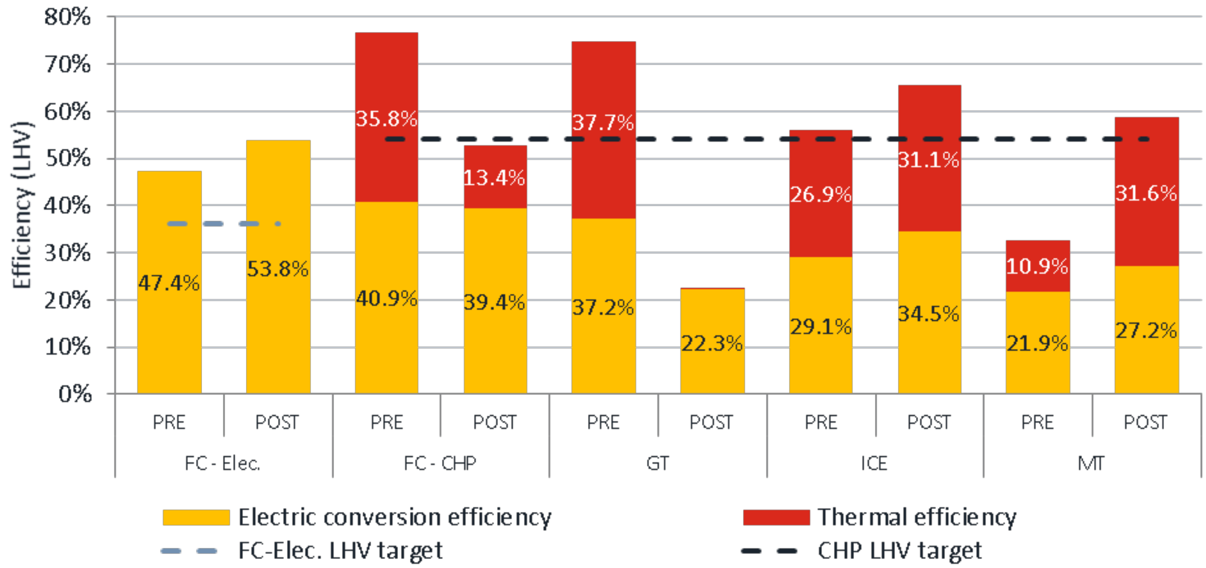


Figure 5-39: 2015 Overall and Component LHV Efficiencies by Technology and SB 412 Pre/Post

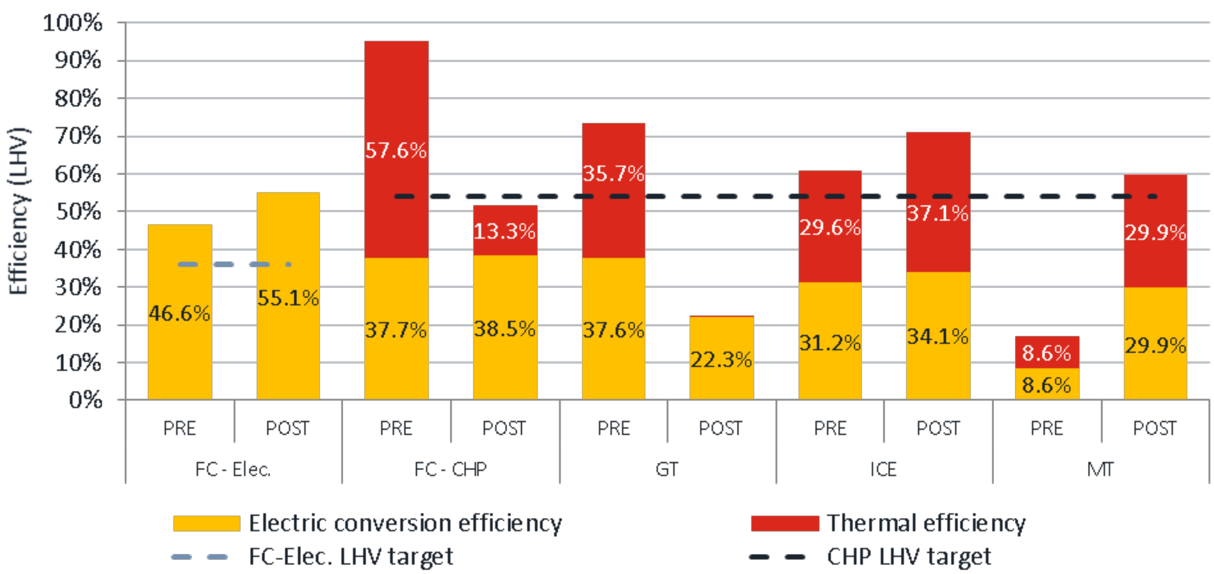


Figure 5-38~~Figure 5-38~~ and Figure 5-39~~Figure 5-39~~ both indicate that post-SB 412 all-electric fuel cells, IC engines, and microturbines are more efficient than their pre-SB 412 counterparts. For all-electric fuel cells, the difference widened from 6.6% to 8.5% 2014 to 2015. The difference also widened for IC engines although pre-SB 412 projects improved in both electric and thermal efficiency from 2014 to 2015. Pre-SB 412 microturbines suffered large efficiency declines from 2014 to 2015.

Thermal efficiencies are not shown for post-SB 412 gas turbines in Figure 5-38~~Figure 5-38~~ or Figure 5-39~~Figure 5-39~~ because of concerns about participant anonymity and underlying data. We are concerned in general about reporting impacts for the program's two post-SB 412 gas turbines as they might be identifiable. Additionally, data availability and data validity impart these results with relatively high uncertainty. Data available from the EnergySolutions website for one post-SB 412 GT initially were incomplete, missing the last 4 months of 2015. Those data also showed very low useful heat recovery and thus low thermal and overall efficiencies.[12] Data available from the EnergySolutions website for the other GT are markedly different from other SGIP GT. For this GT, high heat recovery needs may have reduced electrical output. It is unclear if any other post-SB 412 GT will operate in this fashion.

Figure 5-38~~Figure 5-38~~ or Figure 5-39~~Figure 5-39~~ do show thermal efficiencies of pre-SB 412 CHP fuel cells in 2014 and 2015 that are markedly higher than previously been observed for the program. They are reported here with reservations about data validity but not about project anonymity. From 2013 to 2015, the number of pre-SB 412 CHP fuel cells with metered heat recovery data fell by 50%, leaving a very small metered sample. Heat recovery data from several projects in the remaining sample have been included but suggest a need for independent confirmation.

5.5 Useful Heat Recovery Rates

Fuel energy that enters SGIP systems is converted into electricity and heat. Certain SGIP technologies are capable of capturing this heat to usefully serve on-site end uses instead of dissipating it to the atmosphere. Except for all-electric fuel cells that achieve high fuel-to-electric conversion efficiencies, the SGIP requires useful heat recovery where natural gas is a system's predominant fuel. Where the predominant fuel is renewable biogas an SGIP system is exempt from the heat recovery requirement. The biogas exemption from heat recovery was introduced in the program's first year.

The end uses served by heat recovery, heating and/or cooling, have important implications for net greenhouse gas emissions. The comparable baseline measures for heating and cooling are a natural gas boiler and a grid-served electric chiller respectively. Useful heat recovery that displaces a baseline boiler will reduce emissions more than if it displaces a baseline electric chiller.

The distribution of end uses served by useful heat recovery from SGIP systems is summarized in Table 25~~Table 25~~. These SGIP systems include some that recover useful heat despite using biogas and so not being required by the program to recover heat.

[12] Repeated attempts to obtain missing data were fruitless, but eventually discovered all data had been removed from the website. The most recent attempt discovered complete 2015 data but heat recovery values different from what were previously available. The newer data suggest better heat recovery but are too late to incorporate into this report.

Table 25: 2015 End Uses Served by Useful Recovered Heat

Useful Heat End Use	Project Count	Rebated Capacity (MW)	Percent of Rebated Capacity*
Cooling Only	43	41.5	15.1%
Heating Only	393	161.1	58.5%
Cooling + Heating	92	72.8	26.4%
Total	***528***	***275.4***	***100%***

* Technologies excluded from total capacity are Advanced Energy Storage, Pressure Reduction Turbine, and Wind

About one-fifth of the SGIP's total capacity is exempt from the waste heat recovery requirement. The remaining 528 projects recover waste heat to serve onsite end uses.

5.6 Natural Gas Impacts

The use of natural gas fuel by many SGIP systems results in increased pipeline transport of natural gas in California. The useful recovery of heat that displaces natural gas boilers mitigates this increase to some extent. Figure 5-40 shows the gross and net natural gas consumption from 2003 to 2015 in millions of Therms. The total column height is the gross consumption by SGIP systems. The red upper portion of the column is consumption avoided by recovering waste heat to displace boilers. The gold lower portion of the column then is the net consumption. The values shown on the lower portions are net consumption.

Figure 5-40: 2015 Annual Natural Gas Consumption by SGIP Projects

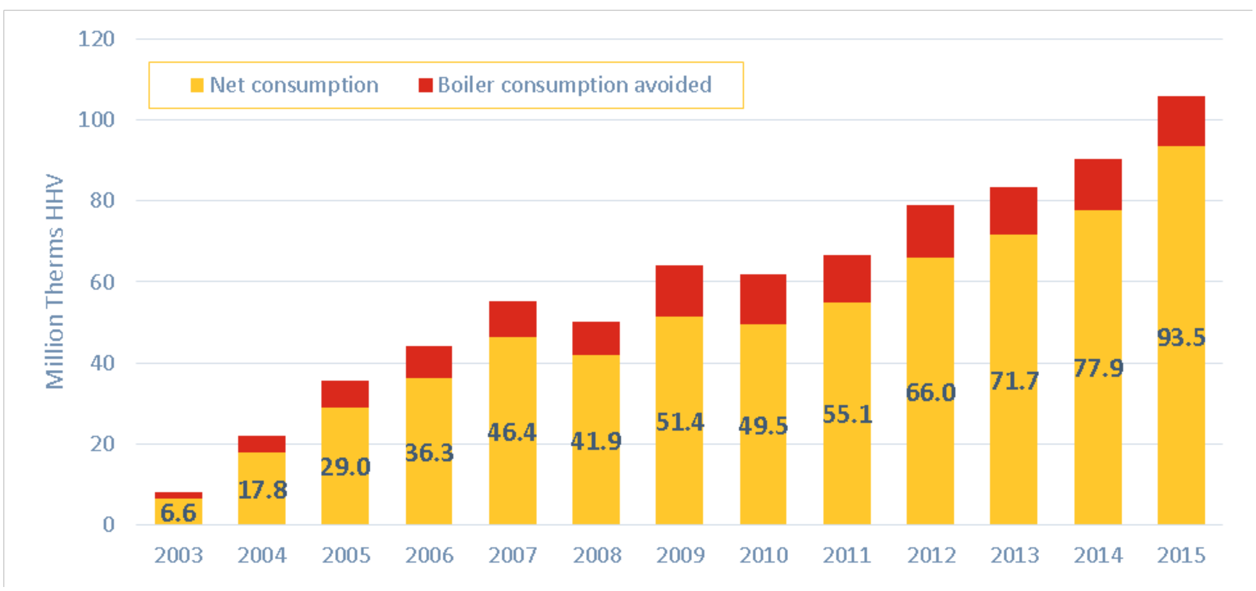
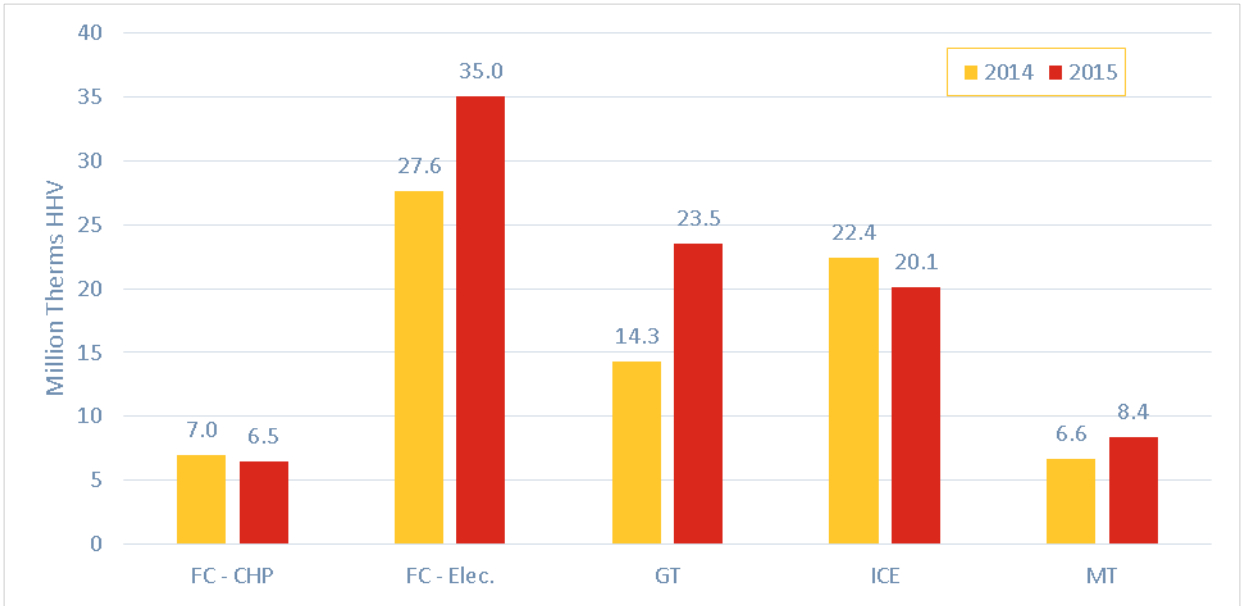


Figure 5-41 shows natural gas net impacts from 2014 and 2015 by technology.

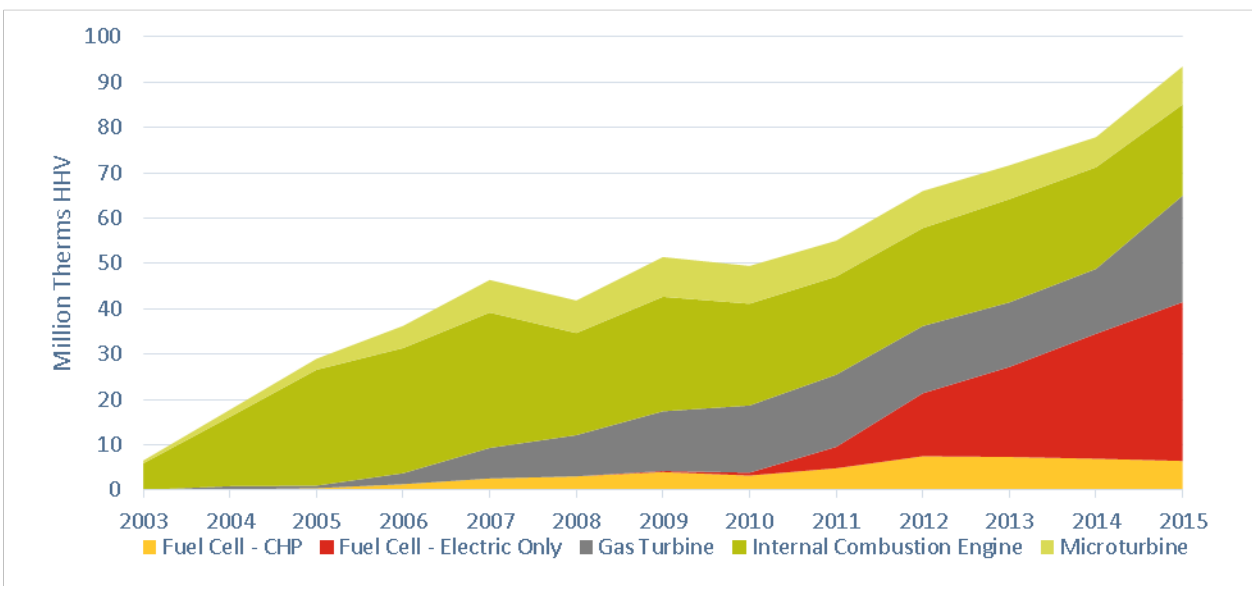
Figure 5-41: 2014 and 2015 Annual Natural Gas Net Consumption by Technology



All-electric fuel cells led natural gas net consumption in 2014 and 2015. This is expected given the large numbers of these projects in the program. Gas turbine net consumption jumped from 2014 to 2015. Modest changes in net consumption occurred between 2014 and 2015 for the other technologies.

Figure 5-42 shows growth in natural consumption from 2013 to 2015 by technology.

Figure 5-42: 2014 and 2015 Annual Natural Gas Net Consumption by Technology



5.7 Assessment of PBI Influence

All projects 30 kW and larger that apply to the SGIP on or after the eleventh program year (PY11) receive their payment through a Performance Based Incentive (PBI). The PBI payment mechanism is expected to improve utilization performance relative to performance under the older upfront, single-payment mechanism. It encourages projects to meet minimum GHG emissions and annual capacity factor targets.[13] Under the PBI rules, eligible projects will receive 50% of their incentive payment upon project completion and up to 50% over the first 5 years of performance. The latter payments are based on actual metered performance data that the projects must provide. The minimum capacity factor targets upon which PBI payment rates are based are presented in Table 5-26.

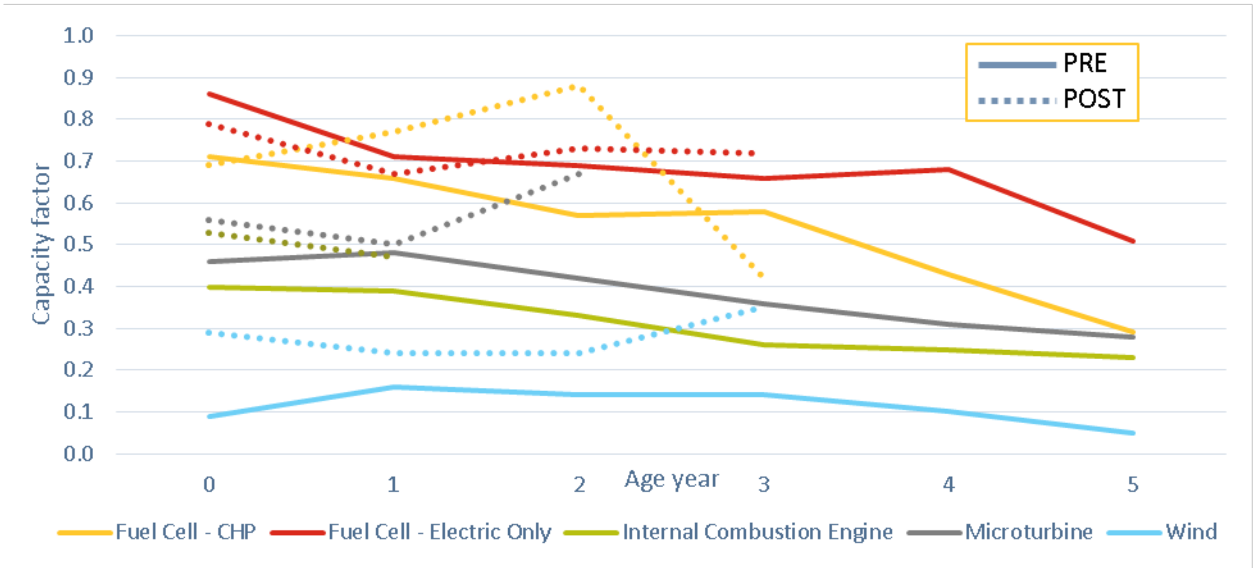
Table 5-26: Minimum Required PBI Capacity Factors

Technology Type	Capacity Factor
Wind Turbine	0.25
All Other Technologies	0.80

One goal of the PBI mechanism is to create a larger incentive for projects to meet performance targets for at least 5 years. In 2015, the earliest PBI projects still have yet to reach 5 years. This allows comparisons of only their first few years to pre-SB 412 projects. Figure 5-43 shows utilization performance in terms of capacity weighted average annual capacity factors by age year and technology and pre-and post-SB 412.

[13] PBI payments are reduced by half in years when a project's average emission rate is equal to or greater than 398 kg CO2/MWh but less than 417 kg CO2/MWh. Projects that exceed an average emission rate of 417 kg CO2/MWh in any given year will receive no PBI payment for that year.

Figure 5-43: 2015 Average Annual Capacity Factors by Technology, SB 412 Pre/Post, and Age



All-electric fuel cell and CHP fuel cell are the technologies whose post-SB 412 projects had average annual capacity factors that met the 0.8 minimum target in at least one year. Neither IC engines nor microturbines have had their post-SB 412 projects average capacity factor meet that target as yet. All-electric fuel cell projects from pre-and post-SB 412 categories have annual capacity factors following similar trajectories through age year 3. Post-SB 412 CHP fuel cells have diverged first upward and then downward from their pre-SB 412 counterparts. Post-SB 412 IC engines are below the 0.8 target but are exceeding the capacity factors of pre-SB 412 projects. Microturbines likewise are under the target but the post-SB 412 projects are doing increasingly better into age year 2. Post-SB 412 wind exceeds its pre-SB 412 counterpart through age 3, and exceeds the 0.25 minimum target in two of first four years. Only pre-SB 412 all-electric fuel cells exceeded the 0.8 minimum target in the first year of operation.

Going forward, as more post-SB 412 projects enter the program and more data become available, performance differences such as these can continue to be examined to evaluate the influence of the PBI.

AES Impacts

6

6 ADVANCED ENERGY STORAGE IMPACTS

6.1 Overview and Summary of Results

We undertook an analysis of the advanced energy storage ('AES', or 'storage') projects rebated through the SGIP program and operating during 2014 or 2015. This analysis had four goals:

» **To assess AES performance metrics:** including capacity factor, roundtrip efficiency and proportion of charging from PV for PV integrated AES.

» **To characterize AES dispatch:** by analyzing the timing of charge/discharge and metrics designed to reveal customer noncoincident peak demand reduction and TOU rate arbitrage behavior

» **To assess CAISO system coincident peak impacts** of AES

» **To assess the CO_2 impacts** of AES

This section provides a high-level summary of the data, analyses, and results. Subsequent sections provide further detail.

Data

Due to limitations in the type, quantity and quality of data provided we are able to investigate the above goals for only some customer segments and time periods. The project team has performed numerous evaluations of distributed energy resources: we anticipated some gaps and challenges in data collection and prepared evaluation plans to address them. In the end, however, some data limitations proved insurmountable. The primary challenges were:

» **Period covered:** Virtually no metered data were available for 2014.

» **Limited customer load data:** Legal negotiations with utilities delayed provision of customer load data until late August 2016. In addition, one storage vendor provided only anonymized customer data, precluding matching of those customers with utility load data.

» **Poor data quality for residential AES**: Storage charge and discharge data from multiple residential vendors proved biased or inaccurate. Vendors described that measurements at low levels of charge or discharge were less accurate, and that some projects' discharge data readings were biased in either an upward or downward direction (which we were unable to independently confirm). Because a vast majority of residential storage projects show hours at low charge and discharge (e.g. for small parasitic loads), such inaccuracies would potentially skew results. Several projects, for example, exhibited roundtrip efficiencies above 100%. Given the program requirements that this data be readily available for program evaluation, this was cause for concern and significantly hindered our ability to conduct our analysis.

For non-residential projects, we are able to complete the four goals listed above. For residential projects, many of which are paired with PV, our investigation was limited by the poor quality of charge and discharge data. Going forward, we recommend that requirements for collecting and providing sufficiently accurate and high quality data in a timely fashion be clarified and enforced to ensure that progress toward SGIP program goals can be effectively measured.

Non-residential Projects

The available non-residential data for this report are limited to storage charging and storage discharging (kW or kWh) data for 115 projects. The projects are split into two categories: 1) performance-based incentive (PBI) projects (with a rebated capacity of 30 kW or higher), and 2) non-PBI, non-residential projects. See Section 6.2 for further details.

Data was only available for 2 of the 24 projects operating in 2014, making it difficult to conclude anything concrete for that year. Both the projects for which we have data are PBI projects. Note that only 4 (3 PBI, 1 non-PBI) of the non-residential projects with data in 2015 are installed at sites that also have solar PV.[1]

Our sample of 115 non-residential projects represents 21 (72%) of the 29 PBI SGIP projects operating in 2015, plus 94 (64%) of the 146 non-residential, non-PBI SGIP projects operating in 2015. Data for the non-PBI projects represent 64% of all non-residential, non-PBI projects operating under the SGIP program in 2015. The quality of the data from some providers was poor and was provided too late to include our analysis.

Of the 21 PBI SGIP projects in our 2015 sample, we were able to match load data to just 12. These 12 projects came online at varying months during 2015, and only two have a full year of data. Unfortunately, we were unable to match non-PBI, non-residential projects with load data because the storage providers for these projects anonymized their data.

Residential Projects

The residential data used for this AES evaluation were limited to storage-in and storage-out (kW or kWh), as well as solar generation (kW or kWh) data for 34 projects. This data represents roughly 20% of the residential AES projects operating under SGIP in 2015. The residential projects are all the same capacity (slightly under 5 kW), and all but 2 are located within the same IOU service territory. There was a steady ramp-up of projects coming online throughout 2014, and all the projects operated throughout 2015. Unfortunately, there were a host of issues due to the accuracy of the battery measurement system, including biases in both the upwards and downwards directions. These issues are explained further in Section 6.2, and they limited the analyses we could perform on the residential AES projects. None of the analyses that we were able to perform using the biased residential charge/discharge data required customer load data.

Performance Metrics

Non-residential Projects

We investigated two performance metrics for each non-residential storage project: capacity factor and roundtrip efficiency (RTE).

The capacity factor for a power plant is often defined as the actual kWh generated divided by the total possible generation based on the nameplate rating (in kW) and possible hours of operation. The SGIP

[1] Based on SGIP statewide tracking. Note that at least one of these sites does not appear to have any control or coupling between the AES and PV systems.

Handbook assumes 5,200 maximum hours of operation of in a year rather than the full 8,760 hours (60 percent). The capacity factor we calculate is thus:

$$Capacity\ Factor = \frac{kWh\ Discharge\ (kWh)}{Hours\ of\ Data\ Available \times\ Rebated\ Discharge\ Capacity\ (kW) \times\ 60\%}$$

The SGIP assumes that PBI AES discharges for the equivalent of a 10% capacity factor of 5,200 hours or 520 hours over the course of each year.[2] PBI payments are tied to this assumption if they wish to receive their full payment. Non-PBI projects are not required to meet a 10% capacity factor, but the metric is still useful for understanding how much the discharge they are performing.

This analysis revealed that both observed PBI projects operating in 2014 fell short of the 10% capacity factor assumption. In 2015, 18 of the 21 (86%) PBI projects met the 10% assumed capacity factor, making them eligible for the full SGIP payment. Only 40 of the 94 (43%) non-PBI projects displayed discharge capacity factors of at least 10%, suggesting the non-residential, non-PBI projects were not doing a great deal of discharging over the course of 2015. This underscores a striking disparity between the two sets of storage projects, with regards to utilization.

Second, we investigated roundtrip efficiency (RTE), defined as AC-AC roundtrip efficiency: total kWh of discharge from the storage project divided by total kWh of charge.. This metric was calculated over the full time period for which we had charge/discharge data for each project (see Figure 6-1). SGIP's Greenhouse Gas Emission Standard in 2014 and 2015 required that each storage project's RTE was at least 63.5% on an annual basis. Only 25 of the 115 observed projects (22%) operating in 2014 or 2015 satisfied this 63.5% RTE requirement. Over 95% of the PBI projects (20/21) met the 63.5% RTE requirement, whereas only 5% of the Non-PBI projects (5/94) met the 63.5% RTE requirement. See Section 6.3 for further details.

Dispatch Behavior

The vendors that install storage projects provide software and control systems to dispatch the storage. Generally, little or no input from the customer is required, though venders do offer different ways in which customers can provide inputs or manually alter or override the programmed dispatch.

AES providers fill out inspection reports that document the installed projects. These inspection reports include fields that describe the dispatch objectives for the AES projects. We reviewed these descriptions with the intent of determining whether the actual dispatch was consistent with the stated objectives for each project. Unfortunately, the dispatch objective descriptions in the inspection reports frequently describe multiple objectives and are not sufficiently specific to test against actual dispatch data. As a result, we are not able to evaluate how well storage projects are performing relative to their described objectives. It is worth noting, however, that interviews performed by Itron with AES company staff (for a

2 "520 discharge hours" refers to the amount energy released when discharging a battery at full capacity for 520 hours. AES projects typically discharge during peak weekday periods and are unable to discharge during their charging period. For this reason, 5,200 hours per year will be used for the purposes of calculating the capacity factor for AES projects. That is, a project may discharge at full capacity for 520 hours, or, say, 50% capacity for 1,040 hours – the amount of energy in the two is the same, each constituting 520 discharge hours.

yet-to-be-released SGIP market transformation report) indicated that for the majority of installers, peak demand reduction is the primary driver for non-residential projects. Section 6.4 provides further detail.

Timing of Battery Activity

Non-residential Projects

We performed analyses to understand aggregated battery dispatch. The results suggest that in 2015, charging occurred predominantly overnight and discharging occurred consistently in the late afternoon and all evening. See Section 6.5 for further details.

Residential Projects

Our analysis of aggregated battery dispatch and solar generation data from the residential storage providers in our sample suggests that in 2015, charging occurred predominately from customers' connected solar generation: battery charging activity and solar generation activity consistently peaked in similar hours. Battery discharge occurred consistently during late afternoon summer hours, coinciding with higher time-of-use residential rates for projects' service territory. See Section 6.5 for further details.

Coincident Peak Impacts

Non-residential Projects

For 2015, PBI storage projects show much lower power consumption in all of the top 200 system hours[3] than they do on average during the summer. This suggests that storage customers are at least somewhat avoiding charging during peak hours. The PBI projects show a net discharge during peak hours, so they are reducing overall demand and benefiting the grid. After accounting for the size of the total SGIP population, we estimate that, on average across the system's top 50 hours of the year, 235 kW of discharging occurs from PBI systems. It should be noted that the small sample sizes and large variance associated with this statistic lead to a relatively large margin of error. See Appendix E for further explanation.

In contrast with the PBI projects, non-PBI projects are, in aggregate, net *charging* during the top 200 hours. This result is significant at the 10% level for each of the program administrators. For the non-PBI projects, we estimate 18 kW of net charging during the top 50 CAISO system demand hours in 2015. The fact that non-PBI customers are, in aggregate, charging during the top 200 hours suggests that the incentives offered to them to avoid charging during peak hours are insufficient, and there is an opportunity to make better use of these non-PBI projects from a grid-level perspective. Since the PBI projects have significantly higher capacities than the non-PBI projects, the aggregate estimated impact across the full population[4] of non-residential AES projects operating in 2015 was a net discharge during peak CAISO system hours.

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[3] 'System' in Section 6 refers to the CAISO system as a whole.

[4] Two large, older AES non-PBI projects are excluded from this analysis. These projects were incentivized before the PBI rules were in place:

As explained in Section 6.7, without special rates or programs, the economic incentive for customers to dispatch storage for utility grid or ratepayer benefits is limited to the pricing signal provided by TOU rates and demand charges. This leaves much of the capability of energy storage to provide peak load reductions for electric grid and utility ratepayer benefits untapped. As compared to standard TOU and demand charge rates, utility programs or more dynamic tariffs that enable utility dispatch or better align customer incentives could significantly increase the amount of storage that is discharging during system and/or distribution peak load hours.

CO_2 Emission Impacts

The CO_2 emissions attributable to a storage project depends on two factors:

1. *When* the projects are charging and discharging, i.e. the marginal grid emissions during the hours of charge and discharge, and
2. The *roundtrip efficiency* of the project.

We sought to assess the CO_2 emissions impacts of the storage projects as they were operating in 2015. See Section 7 for further details. It is worth noting that this report does not attempt to quantify any CO_2 benefits flowing from the role of storage projects in grid integration of renewable energy generation resources. This could be an interesting area of analysis in future impact evaluation reports, as California continues on the path to a high-renewables future.

Non-residential Projects

We find that dispatch behavior of the 115 observed non-residential storage projects increased total CO_2 emissions in 2015. This was true both for the PBI systems, on average, and non-PBI non-residential projects, on average.

Despite being charged at times when marginal emissions from generating resources were low, storage project inefficiencies meant that the 21 *observed* PBI storage projects actually increased emissions by 13 tons of CO_2 in 2015. This corresponds to an estimate of 21 tons of CO_2 for the *population* of SGIP PBI storage projects operating in 2015. A dispatch profile that was fully optimized to reduce emissions rather than other factors like customer peak demand charges could yield different results in the future.

Emissions increases from the 94 non-PBI, non-residential projects were more significant, since they were often charging during high marginal emissions hours. The 94 *observed* non-PBI, non-residential projects increased emissions by 19 tons of CO_2 in 2015. This corresponds to an estimate of 39 tons of CO_2 for the *population* of SGIP non-PBI, non-residential storage projects operating in 2015.

We were able to infer the theoretical average roundtrip efficiency values needed for non-residential SGIP storage projects to produce carbon neutral impacts *if they continue to be operated as they were in 2015*. For the PBI projects, these range from 80% (Summer) to 89% (Winter). Because the non-PBI projects

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A 600 kW project that has been offline for some time and therefore had minimal or no impacts in 2014/2015.

A 1,000 kW project that was installed some years ago as part of a micro grid and is controlled by the micro grid. This project may therefore operate substantially differently than the commercial available projects now part of the program that are using proprietary energy or demand reduction algorithms supplied as part of the AES project, and no data for this project were available.

charge, in aggregate, during higher marginal GHG emission hours, it is not feasible for them to reduce GHG emissions even at 100% efficiency if they continue to follow 2015 dispatch patterns.

Looking Ahead

The coincident peak and carbon dioxide emissions impacts assessed in this evaluation for non-residential projects are based on storage discharging behavior observed in 2014 and 2015 and assessments of peak system demand hours and marginal emissions during this timeframe. Going forward, California is on track to increase its renewable generation substantially, which will magnify the potential grid and emission benefits of well-timed storage dispatch. With restructured incentives and tariffs, AES projects have the potential to reduce customer peak impacts and carbon dioxide emissions in the future.

Specifically, we recommend that policymakers consider 1) increasing storage project RTE requirements and enforcement, 2) adjusting rate design to better incentivize desired behavior, and 3) facilitating utility dispatch or third-party dispatch with aligned incentives to encourage charging and discharging for maximum coincident system peak load and GHG emission reductions. Section 6.7 provides more detail.

6.2 Characterization of Data, Sources, and Customers

Non-residential Projects

We performed analyses on two types of non-residential storage projects, performance-based incentive (PBI) project, and non-PBI projects. PBI systems are defined as those with a rated capacity of 30 kW or higher. Our sample of 115 non-residential projects represents 21 (72%) of the 29 PBI[5] SGIP projects operating in 2015, plus 94 (64%) of the 146 non-residential, non-PBI SGIP projects operating in 2015. Data for the non-PBI projects are all from one storage provider, but represent 64% of all non-residential, non-PBI projects operating under the SGIP in 2015.

Unless otherwise stated, the non-residential AES results described in this report are for the sample of 115 non-residential projects for which we have usable data. However, Sections 6.6 and 7.6 provide estimates of 2015 coincident peak and emissions impacts for the *full population* of 175 non-residential SGIP storage projects by scaling up sample results using the known sizes of the various program subclasses. That is, we compare the amount of kW of capacity in our sample size to the amount of capacity installed in the population by year's end to estimate what various program-wide impacts might be. These scale-up values are shown in Table 6-1, Table 6-2, Table 6-3 and Table 6-4 below.

Results are presented separately for 2014 and 2015. However, only two (both PBI) projects had data available in 2014. This extremely small sample is insufficient to allow any concrete conclusions to be drawn for 2014.

For 2015, storage charge and discharge data is available for 21 out of 29 (72%) PBI projects and 94 out of 146 (64%) non-PBI projects. These projects represent 70% and 41% of the rebated capacity for PBI and non-PBI projects, respectively. For most of these projects, data is available only from August 2015 onward (Figure 6-1). We are able to match load data with only 12 of these 21 PBI projects. These 12 projects came

5 *2016 Self-Generation Incentive Program Handbook,* 2016, available at https://www.selfgenca.com/home/resources/.

online at varying months during 2015, and only two have a full year of matched load data. Unfortunately, we have no way of matching non-PBI, non-residential projects with load data because the storage providers anonymized their dispatch data. Table 6-1, Table 6-2, Table 6-3, and Table 6-4 summarize the data available for this AES evaluation.

Only 4 systems (3 PBI, 1 non-PBI) are paired with PV.

Table 6-1: Comparison of Project Counts in Sample and Population, Projects Operating During 2014

Count	PBI Projects			Non-PBI, Non-Residential Projects			Total	
	Sample	Population	% of Population in Sample	Sample	Population	% of Population in Sample	Sample	Population
PG&E	2	4	50%	0	16	0%	2	20
SCE	0	0	N/A	0	3	0%	0	3
SDG&E	0	0	N/A	0	1	0%	0	1
Total	**2**	**4**	**50%**	**0**	**20**	**0%**	**2**	**24**

Table 6-2: Comparison of Rebated Capacity (kW) in Sample and Population, Projects Operating During 2014

kW	PBI Projects			Non-PBI, Non-Residential Projects			Total	
	Sample	Population	% of Population in Sample	Sample	Population	% of Population in Sample	Sample	Population
PG&E	1,300	1,536	85%	0	1,304	0%	1,300	2,840
SCE	0	0	N/A	0	629	0%	0	629
SDG&E	0	0	N/A	0	5	0%	0	5
Total	**1,300**	**1,536**	**85%**	**0**	**1,937**	**0%**	**1,300**	**3,474**

Table 6-3: Comparison of Project Counts in Sample and Population, Projects Operating During 2015

Count	PBI Projects			Non-PBI, Non-Residential Projects			Total	
	Sample	Population	% of Population in Sample	Sample	Population	% of Population in Sample	Sample	Population
PG&E	15	21	71%	57	81	70%	72	102
SCE	6	8	75%	19	40	48%	25	48
SDG&E	0	0	N/A	18	25	72%	18	25
Total	**21**	**29**	**72%**	**94**	**146**	**64%**	**115**	**175**

Table 6-4: Comparison of Rebated Capacity (kW) in Sample and Population, Projects Operating During 2015

kW	PBI Projects			Non-PBI, Non-Residential Projects			Total	
	Sample	Population	% of Population in Sample	Sample	Population	% of Population in Sample	Sample	Population
PG&E	8,820	10,825	81%	1,117	2,639	42%	9,937	13,464
SCE	2,310	5,180	45%	344	1,420	24%	2,654	6,600
SDG&E	0	0	N/A	394	445	89%	394	445
Total	**11,129**	**16,005**	**70%**	**1,855**	**4,504**	**41%**	**12,985**	**20,509**

The following figures highlight the characteristics of the data available for the projects analyzed. Figure 6-1 shows the number of projects with data available, by month. For 2014, data was available for only 2 PBI projects, shown in red. Data for non-PBI, non-residential projects was only available for 2015, as shown in yellow. Data was available for only a limited number of projects through the first half of 2015. Figure 6-2 displays the number of months of data available for each storage project. For example, the first column shows that for one non-PBI, non-residential project (in yellow), we had only one month of data. The column for 12 months shows a year worth of data was available for 2 PBI projects (in red) and 11 non-PBI, non-residential projects (in yellow): a total of 13 projects. For the 115 projects in our sample, we had access to almost all 15-min charge and discharge data: the data density between a project's first available date and last available date ranged from 91% to 100% of all 15-minute intervals, averaging around 98% per project.

Figure 6-1: Count of Non-Residential SGIP Storage Projects with Data Available, by Month, 2014 – 2015

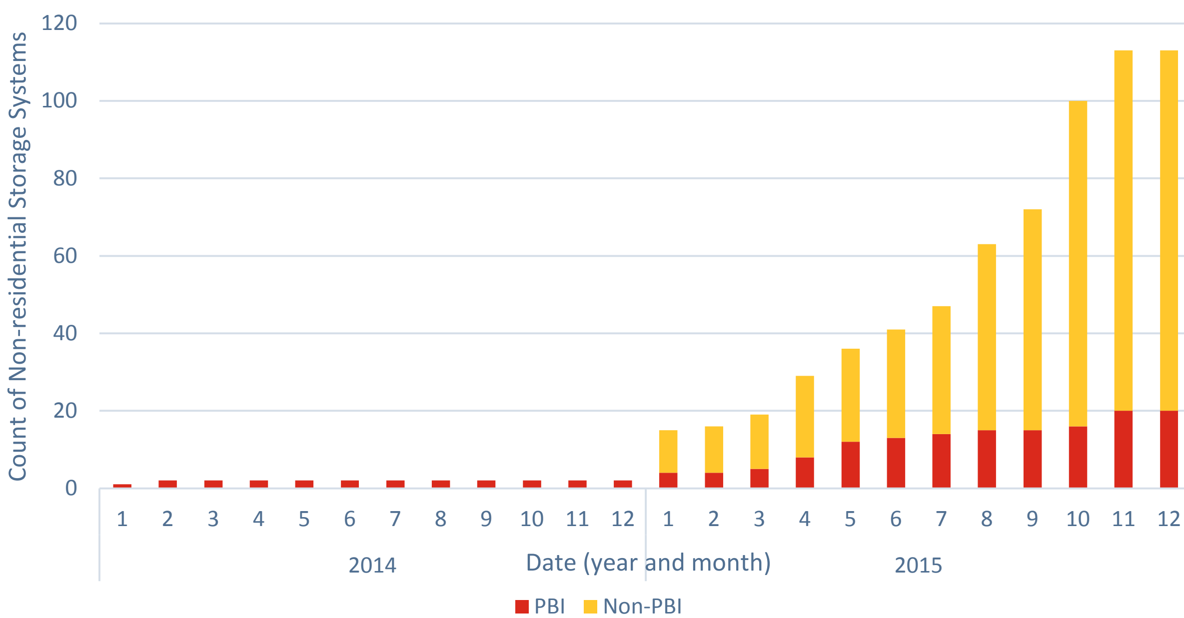
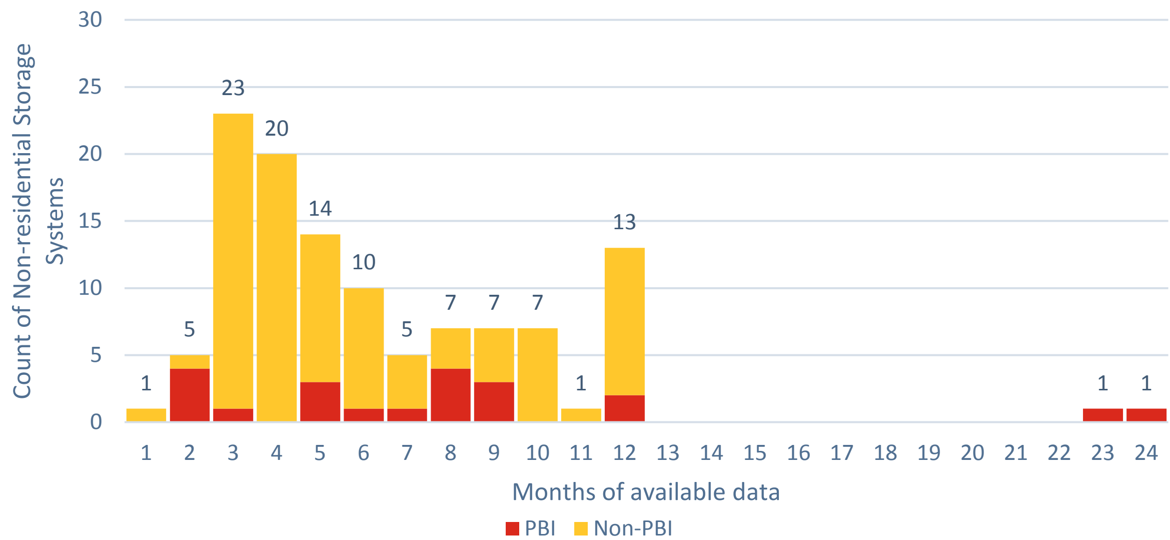


Figure 6-2: Histogram of Months of Available Data, 2014 – 2015



In addition to incentive type, another important point of difference between the PBI and non-PBI projects is rebated capacity. PBI projects are defined as those with a rebated capacity of 30 kW or higher.[6] Of the two available projects operating in 2014 (both PBI), one had a 300 kW rebated capacity and the other had a 1,000 kW rebated capacity. For the projects operating in 2015: the PBI projects had capacities ranging from 100 kW to 2400 kW, and the non-PBI projects ranged between 9 kW and 29.99 kW. Figure 6-3 and Figure 6-4 show the distribution of capacities for each of the two classes.

6 *2016 Self-Generation Incentive Program Handbook,* 2015, available at https://www.selfgenca.com/home/resources/ (herein after '2015 SGIP Handbook')

Figure 6-3: Histogram of PBI AES Projects Rebated Capacities with Data Available

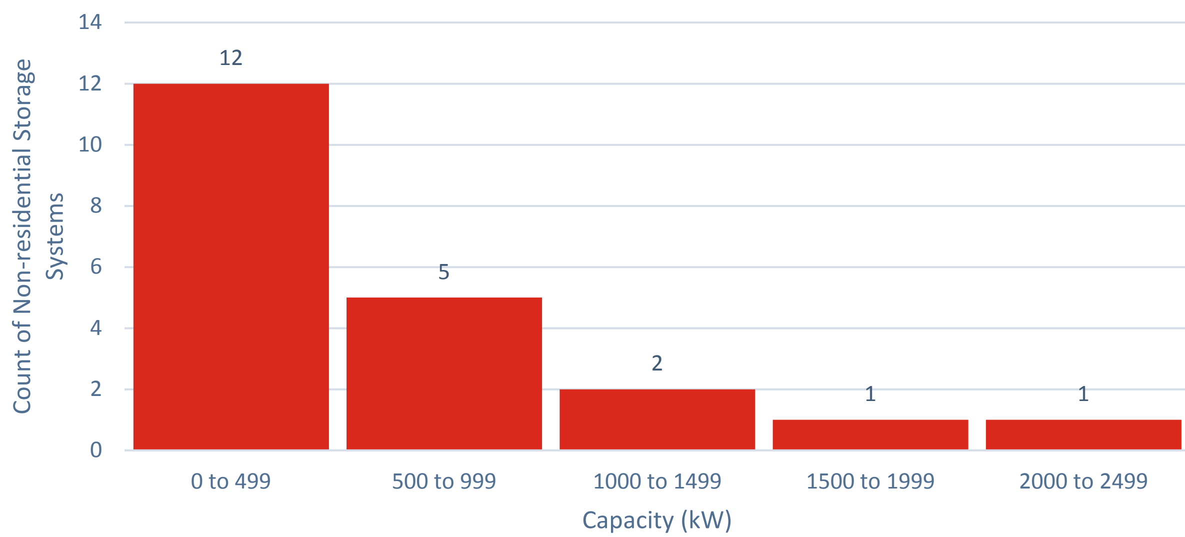
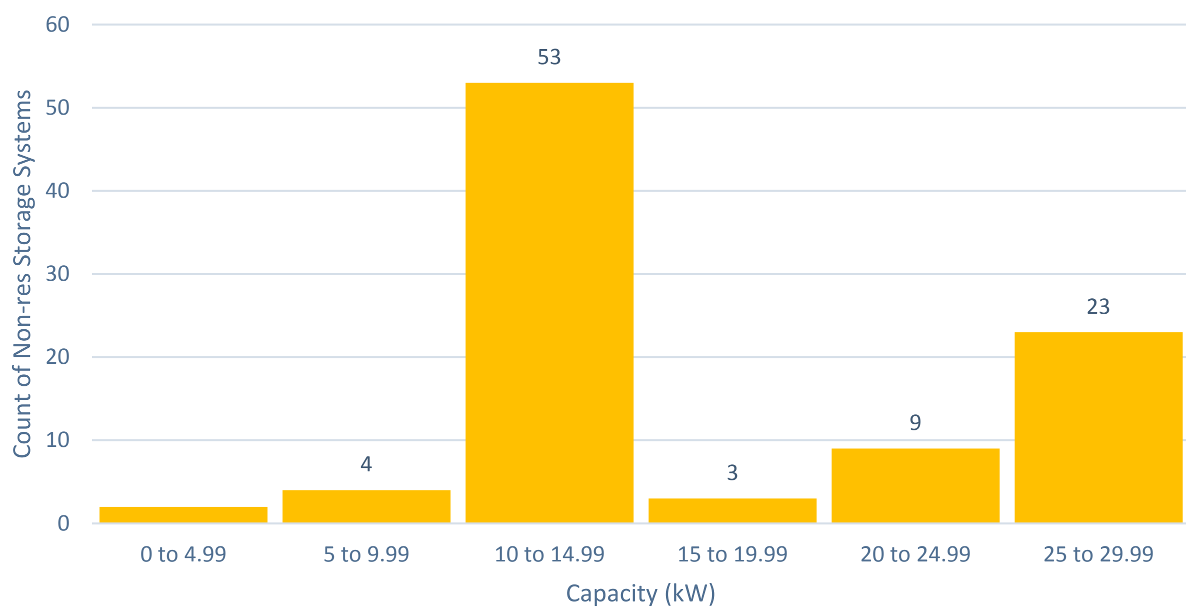


Figure 6-4: Histogram of Non-PBI AES Project Rebated Capacities with Data Available



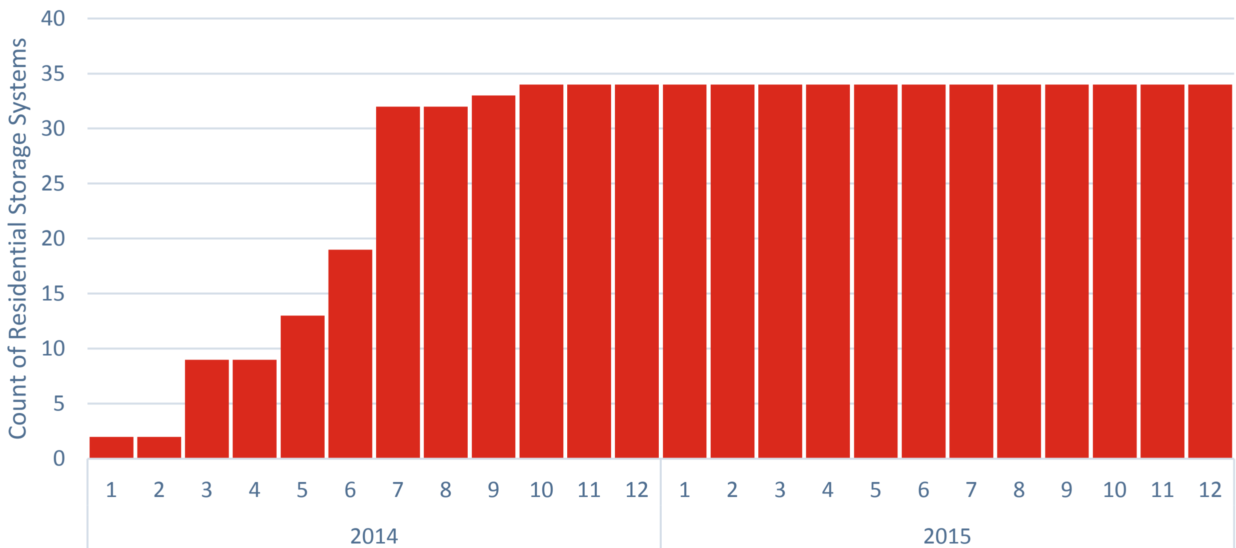
Residential Projects

Our sample of residential project data accounts for 20% of the projects rebated in 2014 and 2015. One provider gave data only for 2016, which is not included in the period of analysis for this report. This provider informed our team that their residential projects were essentially idle in 2015 and are being cycled so that they are in accordance with program requirements in 2016.

All of these projects are battery systems paired with solar PV generators, and thus we have data for both battery charge/discharge and solar generation. As data for all the residential projects are sourced from the same provider, they all have the same battery capacity. As Figure 6-5 below shows, we have data for all these residential projects for all of 2015.

Unfortunately, there are significant issues with the data accuracy, particularly due to the battery measurement systems. In conversation with the provider, we learned these biases include both parasitic losses at low battery usage, and measurement inaccuracies at higher battery usage levels. Because a vast majority of hours are at low charge and discharge levels (e.g. for small parasitic loads), such inaccuracies would potentially skew results. For example, a significant portion of the projects see hours with efficiencies greater than 100%. It was not possible to for the project team to use statistical methods to independently correct biases in both the upwards and downwards. Therefore, we were only able to undertake a subset of our analyses for the residential projects. This is reflected in each subsection below. We were able to generate high-level insights regarding discharge timing, which we detail in Section 6.5.

Figure 6-5: Count of Residential SGIP Storage Projects with Data Available, by Month, 2014 – 2015



A summary of the sample of residential data versus the program population is provided in Table 6-5.

Table 6-5: Comparison of AES Project Counts and Capacity in Sample and Population, Projects Operating During 2015

Count	Residential Projects			Residential Rebated Capacity (kW)		
	Sample	Population	% of Population in Sample	Sample	Population	% of Population in Sample
PG&E	33	134	25%	149	649	23%
SCE	0	11	0%	0	53	0%
SDG&E	1	23	4%	5	114	4%
Total	**34**	**168**	**20%**	**153**	**816**	**19%**

6.3 Performance Metrics

Capacity Factor

Non-residential Projects

The capacity factor for a power plant is defined as the actual kWh generated divided by the total possible generation based on the nameplate rating (in kW) and possible hours of operation. The SGIP handbook assumes 5,200 maximum hours of operation of in a year rather than the full 8,760 hours (60 percent). This is to account for the fact that "Advanced Energy Storage Projects typically discharge during peak weekday periods and are unable to discharge during their charging period."[7] The AES capacity factor we calculate is thus:

$$Capacity\ Factor = \frac{kWh\ Discharge\ (kWh)}{Hours\ of\ Data\ Available \times\ Rebated\ Discharge\ Capacity\ (kW) \times\ 60\%}$$

The SGIP Handbook requires that PBI projects achieve an AES capacity factor of at least 10% per the above formula, 520 hours over the course of each year, to receive full payment.[8] Non-PBI projects are not required to meet a 10% capacity factor, but the metric is still useful for understanding how much charge and discharge they are providing.

7 See 2015 SGIP Handbook, p. 37.

8 "520 discharge hours" refers to the amount energy released when discharging a battery at full capacity for 520 hours. AES projects typically discharge during peak weekday periods and are unable to discharge during their charging period. For this reason 5,200 hours per year will be used for the purposes of calculating the capacity factor for AES projects. That is, a system may discharge at full capacity for 520 hours, or, say, 50% capacity for 1,040 hours – the amount of energy in the two is the same, each constituting 520 discharge hours.

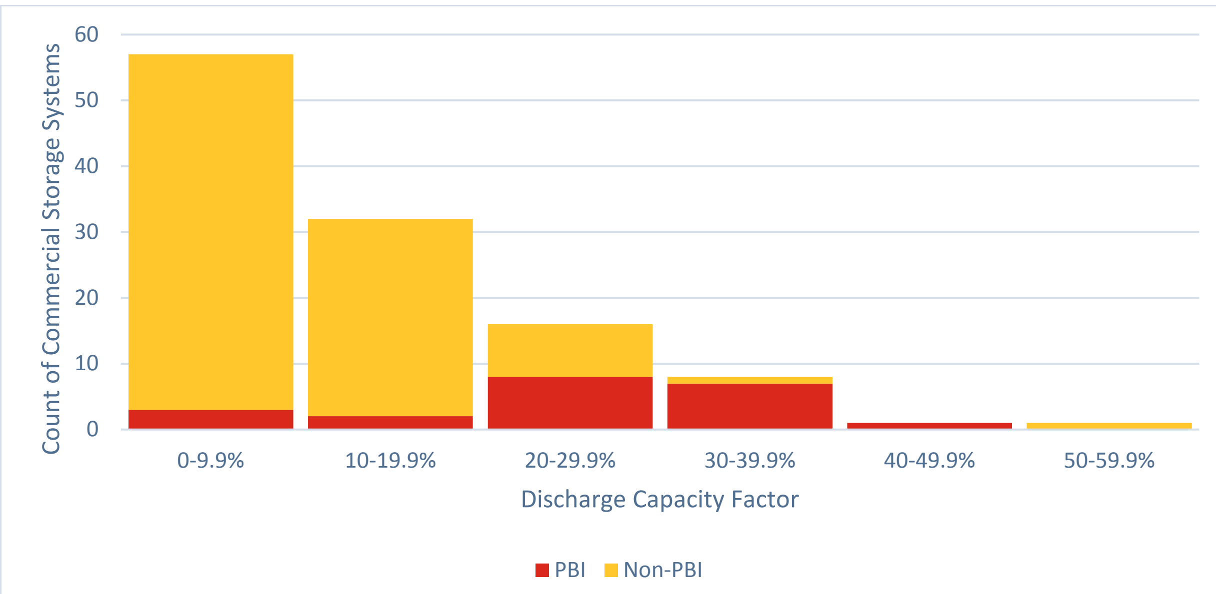
2014

The two (PBI) projects with data for 2014 displayed AES capacity factors of 8.5% and 9.0%, respectively: both below the SGIP assumption of 10% and therefore eligible for less than the full SGIP payment for that year. One project achieved an AES capacity factor of 12.7% in 2015 while the capacity factor for the other project decreased to only 4.3%. The 2015 performance of both these projects can both be seen in the bottom right corner of Figure 6-7.

2015

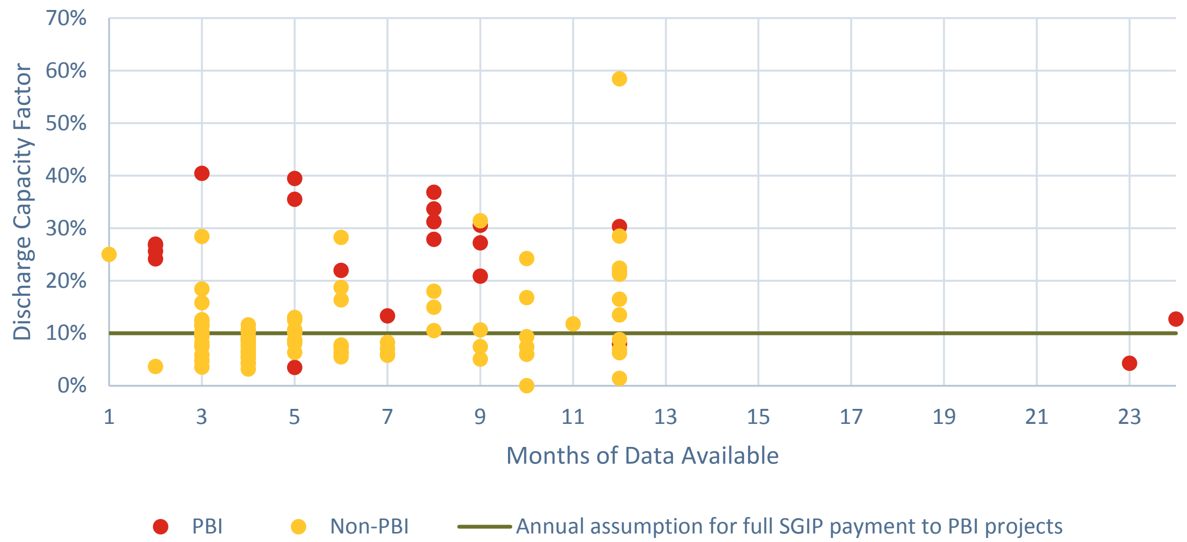
As shown in Figure 6-6, the range of 2015 AES capacity factors across non-residential storage projects varies widely. The first column shows that 3 PBI projects and 54 non-PBI, non-residential projects have an AES capacity factor of less than 10%. We observed 58 of 115 (51%) projects with an AES capacity factor of at least 10% in 2015. Specifically, 18 of the 21 (86%) PBI projects and 40 of the 94 (43%) non-PBI projects displayed AES capacity factors of at least 10%.

Figure 6-6: Histogram of Non-residential AES Discharge Capacity Factor, 2015



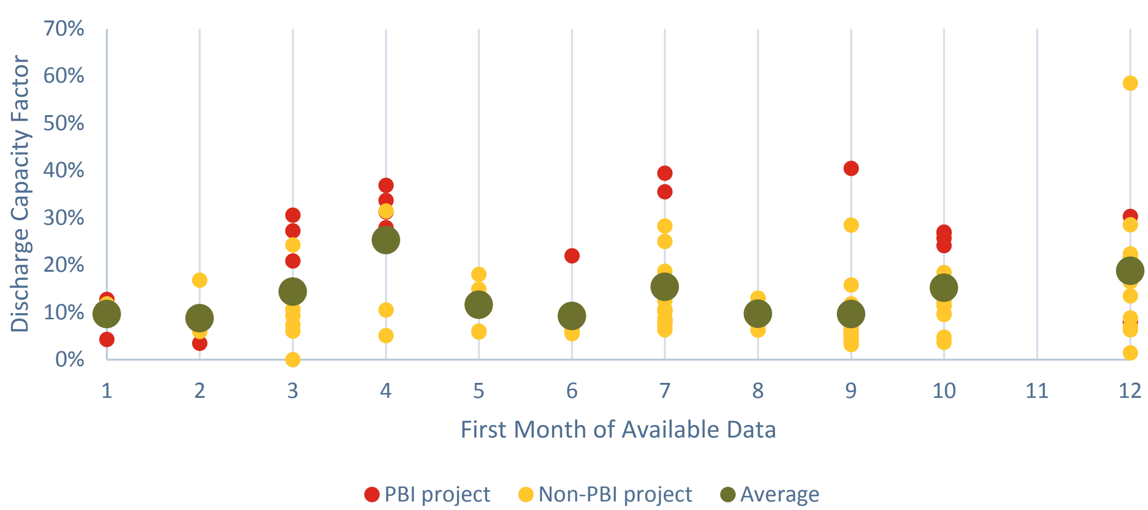
To ensure that the AES capacity factors observed were not merely functions of the amount of data available for a given storage project, we considered capacity factor as a function of the months of data available. See Figure 6-7. The 10% assumption for full payment of PBI projects is marked in Figure 6-7. Given that there is no clear correlation between discharge capacity factor and months of available data, the number of months of data availability doesn't seem to be of concern for this metric. That is, the considerably low discharge capacity factors do not seem to be due to some of the projects' 2015 data being incomplete.

Figure 6-7: AES Capacity Factors as a Function of Months of Data Available for Each Non-Residential Storage Project, 2015



It is worth noting, however, that seasonal variation is not accounted for in this metric. For projects where data is only available for, say, winter months (recall Figure 6-1), data for the summer months when the storage projects may be more active are not available. Figure 6-8 below suggests that the data availability does not bias the results. In this figure, we have plotted the first month for which data was available for each project on the x-axis, and the AES capacity factor on the y-axis. If there were an underlying bias based on what portion of a year's worth of data is analyzed, it should show as a clear trend in this plot (e.g. the vast majority of projects that come on-line in the summer would have higher discharge capacity factors). However, because the trend is essentially flat over all starting months, it appears there is no clear seasonal trend in a project's AES capacity factor given when the project's data first becomes available.

Figure 6-8: Non-residential AES Discharge Capacity Factor by Starting Month of Data, 2015



Residential Projects

Due to the data limitations described in Section 6.2, we were not able to assess capacity factors for residential storage projects.

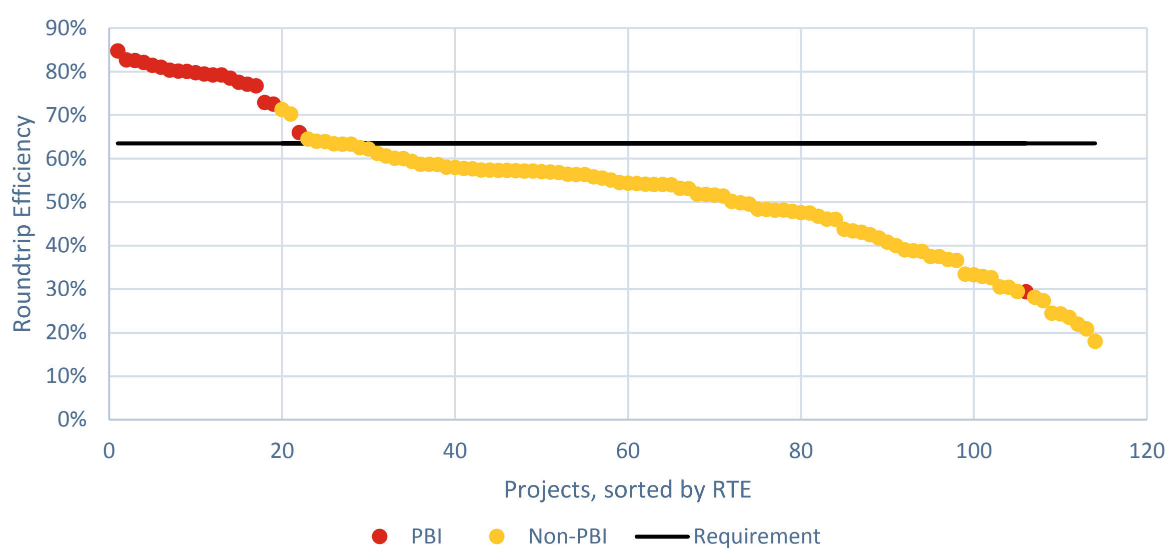
Roundtrip Efficiency

The second performance metric we evaluate is roundtrip efficiency (RTE), which is an eligibility requirement for the SGIP. RTE is defined as AC-AC roundtrip efficiency: total kWh of discharge from the storage project divided by total kWh of charge. The SGIP's 2014 and 2015 Greenhouse Gas Emission Standard required that each storage project's RTE was at least 63.5% on an annual basis.[9] RTE was calculated using the ratio of energy discharged to charging energy over the full time period available for each project. A plot of each project's RTE is shown in Figure 6-9, and Figure 6-11 shows the distribution of RTE's. Only 25 of the 115 observed projects (22%) operating in 2014 or 2015 satisfied the 63.5% RTE requirement. Over 95% of the PBI projects (20/21) met the 63.5% RTE requirement, whereas only 5% of the non-PBI projects (5/94) met the 63.5% RTE requirement.

Non-residential Projects

Because RTE is likely more a measure of the physical capabilities of a project rather than anything time-dependent, we combined 2014 and 2015 data into one statistic for the two PBI projects that operated during 2014.

Figure 6-9: Roundtrip Efficiency for Observed Non-Residential Projects, Sorted by Highest Efficiency



9 See 2015 SGIP Handbook, p. 52. The handful of earlier AES projects were subject to similar but slightly different efficiency requirements.

Similarly, in Figure 6-10 below we use the project's discharge capacity factor in 2015 and graph RTE as a function of discharge capacity factor, along with a logistic regression for both PBI and non-PBI projects. There appears to be positive correlation between RTE and discharge capacity factor, though the R-squared of the regression is low, with an R-squared of 0.60 for the PBI projects and 0.29 for the non-PBI projects.

Figure 6-10: Roundtrip Efficiency versus Capacity Factor

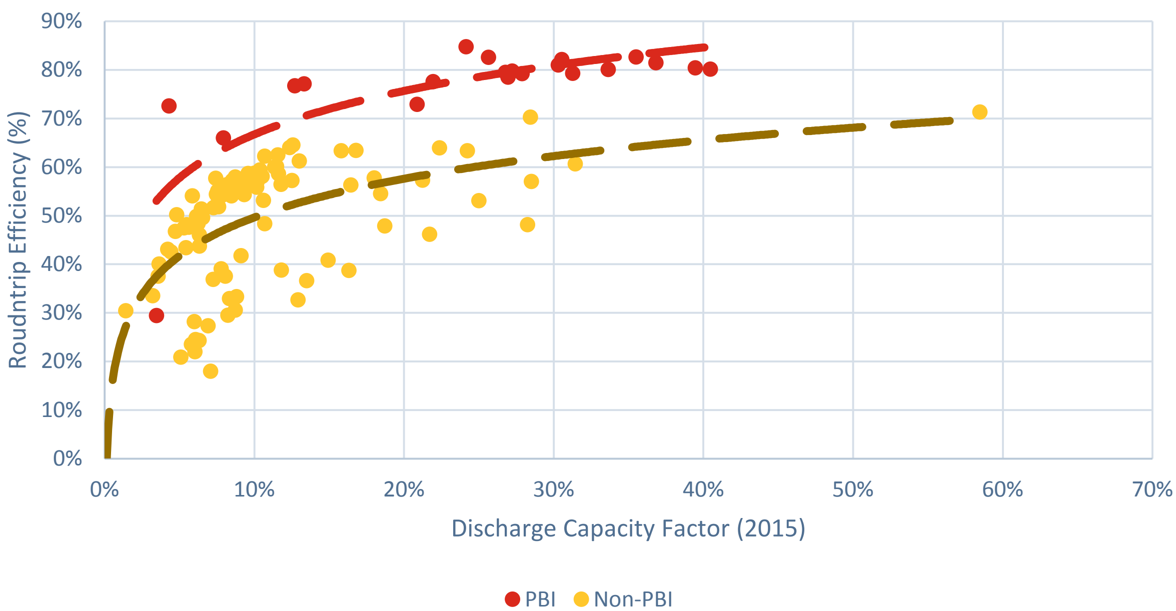
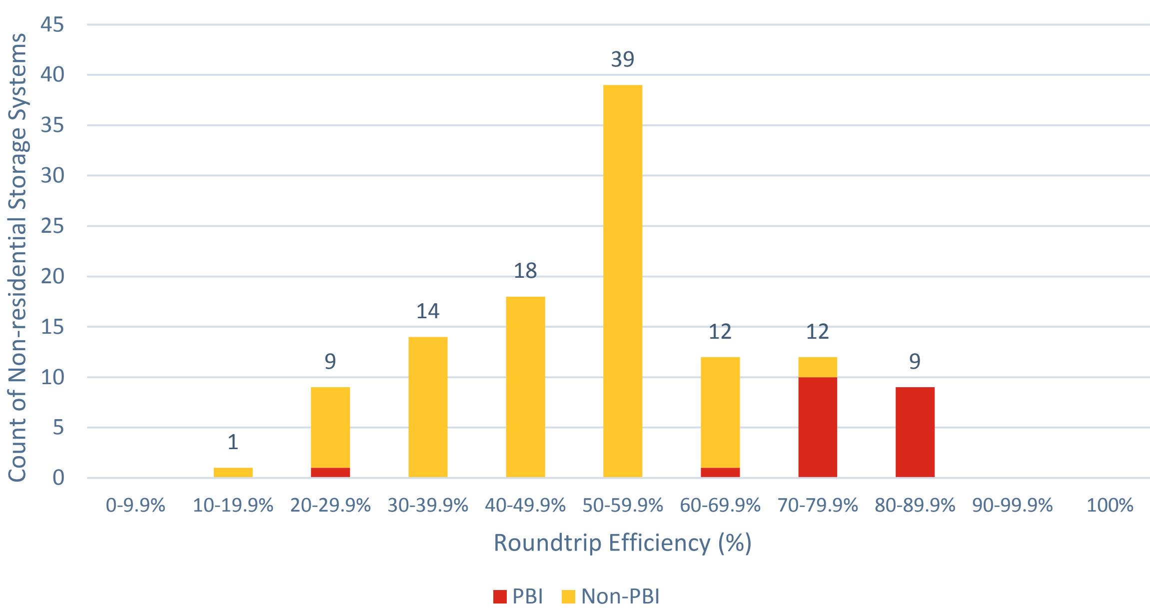


Figure 6-11: Histogram of Roundtrip Efficiencies



Residential Projects

Due to the data limitations described in Section 6.2, we were not able to assess roundtrip efficiencies for residential storage projects

6.4 Dispatch Behavior

The vendors installing storage projects provide software and control systems for dispatch. The vendors have developed algorithms and control schemes to implement various use cases that may interest a customer, such as minimizing TOU energy or demand charges. The vendor selects and implements the control scheme that best matches the customer's preferences. Generally, little or no input from the customer is required, though venders do offer different ways in which customers can provide inputs or manually alter or override the programmed dispatch.

The inspection reports described in Section 4 include fields that describe the dispatch objectives for the AES projects. We reviewed these descriptions with the intent of determining whether the actual dispatch was consistent with the stated objectives for the project. Unfortunately, the descriptions provided in the inspection reports were not specific enough to make such a comparison. In many cases, the objectives are too vague to interpret, such as "grid outages and to assist with overall grid demand," "optimize peak load reduction, improve grid reliability and maximize return," or "backup electrical power if the grid goes down, grid demand shaving, and energy efficiency." Objectives for many commercial projects are also vague with respect to demand charge reductions. Descriptions such as "shave loads" and "optimize facility loads during peak demand times" may or may not have demand charge reduction as a programmed goal. Many descriptions were not dispatch objectives at all, but descriptions of interconnection and power flow such as "A wall-mounted AES inverter will convert grid energy from AC to DC electric to charge the batteries, and vice-versa during battery discharge." Finally, when the descriptions include multiple objectives, they do not describe how those objectives are prioritized and translated into a single objective function. For example, to evaluate projects that provide "demand savings and backup for grid outages," we would need to know what portion of the battery is reserved for backup power and how much capacity remains available to reduce demand.

Interviews performed by Itron with AES company staff (for a yet to be released SGIP market transformation report) indicated that for the majority of installers, peak demand reduction is the primary financial and dispatch driver for non-residential projects.

Because the dispatch objective descriptions are largely insufficiently specific to test against actual dispatch data, we are not able to evaluate how well storage projects are performing relative to these described objectives. An example of the specificity required is provided in the California Solar Initiative Research Development & Demonstration report "PV Integrated Storage: Demonstrating Mutually Beneficial Utility-Customer Business Partnerships:"[10] *"3.5kWh of the battery is reserved for customer backup power, leaving 6.5 kWh available for dispatch to minimize residential customer TOU energy charges. On CPP event days,*

[10] Energy and Environmental Economics (2016). "PV Integrated Storage: Demonstrating Mutually Beneficial Utility-Customer Business Partnerships," for the California Solar Initiative Research, Demonstration and Development Program. Available at: http://calsolarresearch.ca.gov/funded-projects/108-pv-integrated-storage-demonstrating-mutually-beneficial-utility-customer-business-partnerships

the customer backup power reservation is reduced from 3.5kWh to 1.8kWh, leaving 8.2 kWh available for dispatch." (p. 8)

Given the lack of adequate dispatch objectives, we analyzed the extent to which actual dispatch suggests prioritization of each of the following objectives:

1. Time-of-use energy rate arbitrage
2. Minimization of demand charge

It is possible that storage operators are prioritizing other dispatch objectives, such as providing back-up power for reliability purposes. While the analysis of capacity factors in Section 6.3 provides some indication of whether back-up power could be a priority for some operators, we do not have sufficient knowledge or data to make any conclusions.

Non-residential Projects

We investigated the dispatch of PBI projects and non-PBI projects separately.

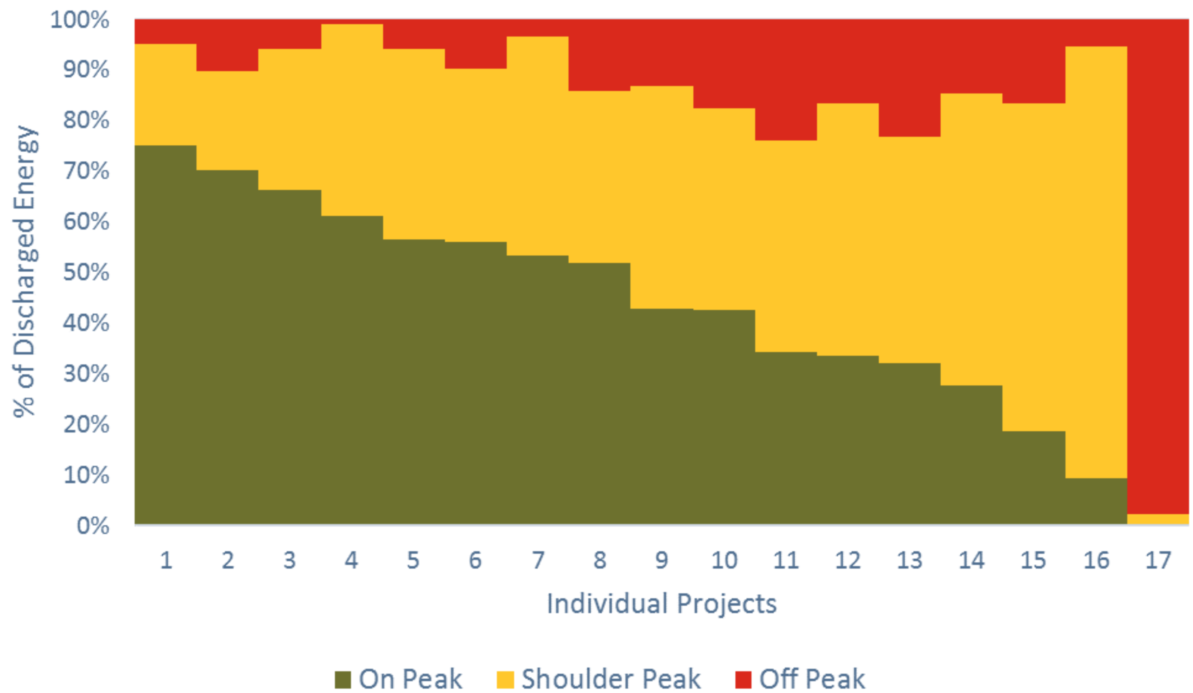
PBI Projects

One use case for non-residential storage projects is TOU rate arbitrage: a battery charges during off-peak hours (with lower retail energy rates) and discharges during on-peak TOU periods (with higher rates). To determine whether customer behavior was strongly correlated with TOU periods, we used generic TOU periods based on hourly approximations of the commercial rates of California's three investor-owned utilities (IOUs), shown below in Figure 6-12.

Figure 6-12: Weekday TOU Assumptions by IOU (Weekends assumed to be all off-peak)

	TOU Assumptions					
	Summer Weekday			Winter Weekday		
	PG&E	SCE	SDG&E	PG&E	SCE	SDG&E
0	off	off	off	off	off	off
1	off	off	off	off	off	off
2	off	off	off	off	off	off
3	off	off	off	off	off	off
4	off	off	off	off	off	off
5	off	off	off	off	off	off
6	off	off	mid	off	off	mid
7	off	off	mid	off	off	mid
8	mid	mid	mid	mid	off	mid
9	mid	mid	mid	mid	mid	mid
10	mid	mid	mid	mid	mid	mid
11	mid	mid	on	mid	mid	mid
12	on	on	on	mid	mid	mid
13	on	on	on	mid	mid	mid
14	on	on	on	mid	mid	mid
15	on	on	on	mid	mid	mid
16	on	on	on	mid	mid	mid
17	on	on	on	mid	mid	on
18	mid	mid	mid	mid	mid	on
19	mid	mid	mid	mid	mid	on
20	mid	mid	mid	mid	off	mid
21	off	mid	mid	off	off	mid
22	off	mid	off	off	off	off
23	off	off	off	off	off	off

Figure 6-13: PBI Project Discharge by Assumed TOU Period (Sorted by On-Peak Percent), 2014 - 2015[11]



While these results show that dispatch of some storage projects was aligned with TOU periods in the 2014 – 2015 period, TOU energy rates are likely not the main driver of this behavior. TOU demand charges and even monthly demand charges may incentivize similar behavior. TOU demand charges would encourage discharge during on-peak periods, but potentially only on days for which the on-peak demand is relatively high. Monthly demand charges would incentivize discharging during on-peak periods if customer load were coincident with the TOU periods. Non-residential loads tend to peak in the afternoons, which aligns with the on-peak TOU periods for the California IOUs. As with TOU demand charges, monthly demand charges would likely encourage discharge during times of peak customer load, and not necessarily every day of the month. As shown in Figure 6-13, all storage projects demonstrated some discharge during off-peak TOU periods. Since a project dispatched exclusively for TOU rate arbitrage would have no reason to discharge any amount during off-peak periods, this suggests that TOU rate arbitrage is not the highest priority for the PBI projects. This discharge pattern may instead be reflective of dispatch that aims to reduce demand charges.

To further explore whether storage projects were dispatched to minimize demand charges, we analyzed peak demand (kW) and demand charges ($) with and without storage for a sample of projects. We were only able to match storage dispatch to load and rate data for 12 projects, and only 9 of these projects were on rates with demand charges. The rates of 6 of these 9 projects included TOU demand charges. Note that installation of most of these projects occurred during 2015, so there are very few projects with

11 Recall that our sample includes only 2 PBI projects that operated in 2014.

a full year's data, which makes assessing annual (1NCP) impacts difficult. We have load and dispatch data for a full summer for only 5 projects, four or which have demand charges.

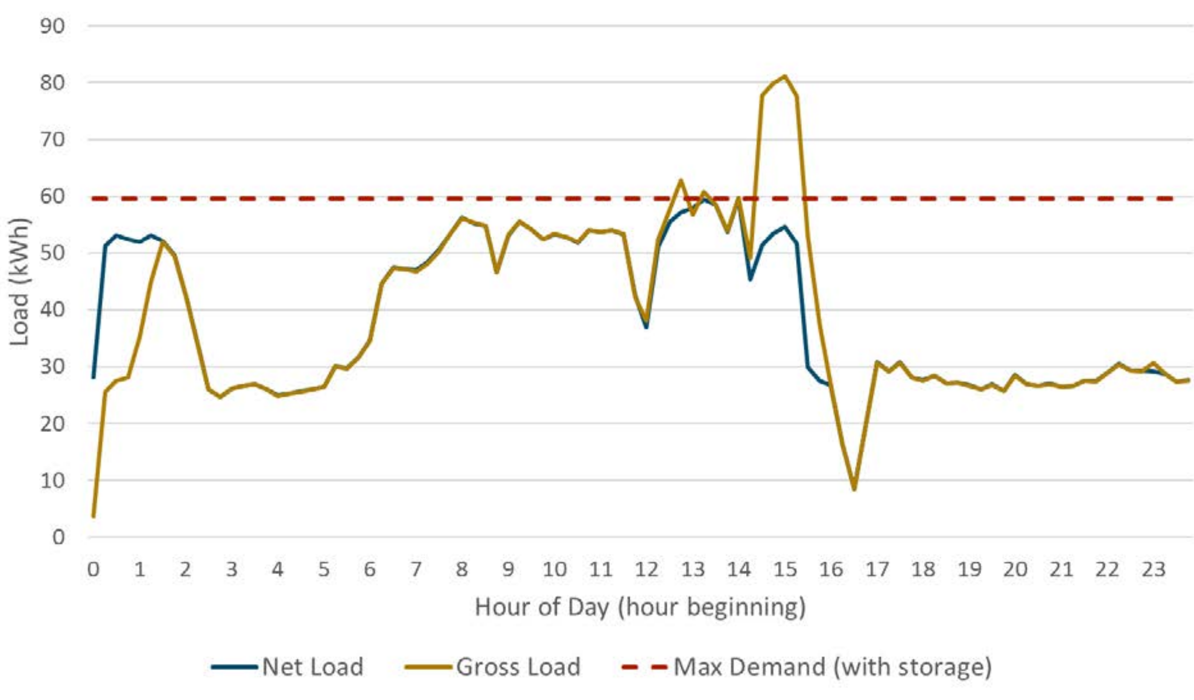
For the five projects with summer load and dispatch data, the average annual demand reduction was 0.8 kW. This metric ranged from a 37.3 kW *increase* in peak demand for a 1,000 kW storage project subject to high on-peak demand charges to a 25.3 kW *reduction* in peak demand for a 200 kW project with only monthly facility-related, non-TOU demand charges. We found the average monthly maximum demand reduction across all sampled projects with demand charges to be 0.06 kW per kW rebated storage capacity.

In total, the 9 sampled storage projects subject to demand charges saved about $20,000 ($312/month) on demand charges while they were online in 2015. This equates to about $0.8 per kW rebated storage capacity.

Figure 6-14 portrays information about storage dispatch and its impact on peak demand for an example PBI project. This PBI customer's retail rate includes a monthly facilities demand charge and no TOU demand charges. The gold line depicts the customer's gross load (i.e. the total electricity demand from a given site or customer), and the blue line depicts the customer's net load (i.e. taking into account storage charge and discharge). As shown in the graph, storage reduces the customers' peak demand on this day from 81 kW to 60 kW. The storage charges at night and discharges during the customers' peak daily demand period. The monthly demand reduction for this project in July was 26.4 kW.

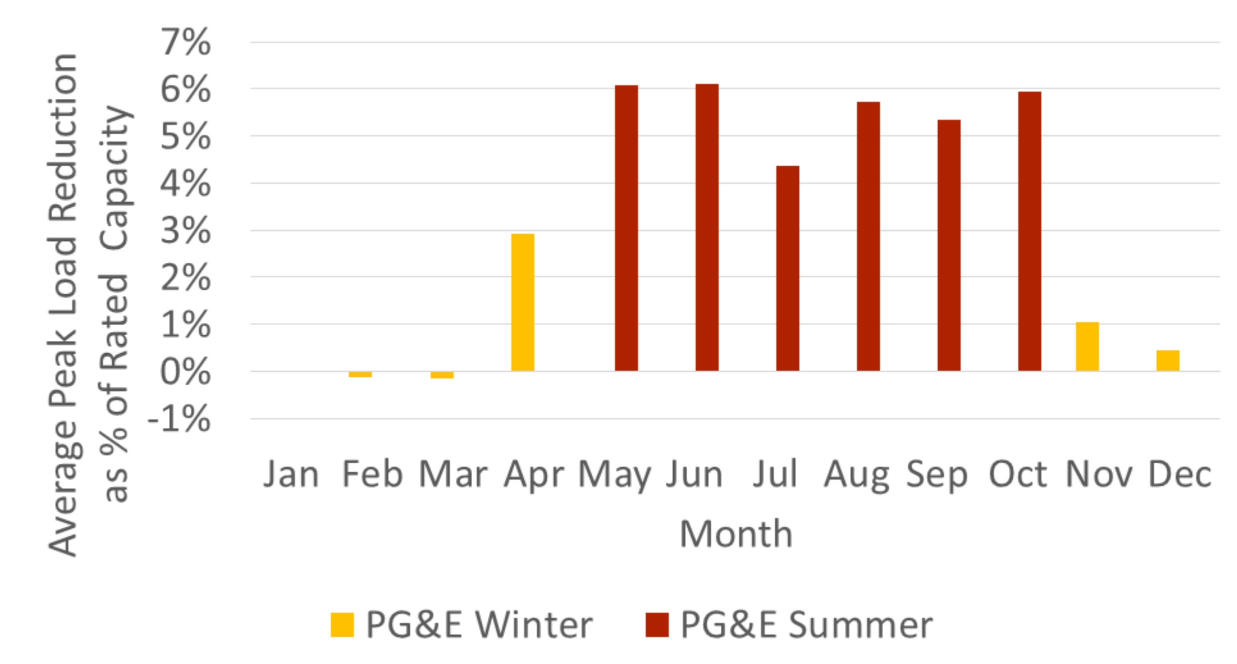
Figure 6-14: Example Storage Dispatch of a PBI Project on a Sample Day in July (200kW Capacity Project)

Many non-residential retail rates include higher demand charges in the summer than in the winter. We explored the possibility that this would incentivize relatively more demand charge minimization behavior in the summer. Figure 6-15 indicates that a seasonal discrepancy exists, although some storage projects may be dispatching to reduce demand charges throughout the year. In particular, we can see that summer



months tend to have a significantly higher peak load reduction as a percentage of rebated capacity, as compared to winter months. This figure encompasses data from the five PG&E projects with demand charges and load data. Note that the installation of all except one of these projects occurred part of the way through the year.

Figure 6-15: Average Non-Coincident Customer Peak Demand Reduction by Month (% of rebated storage capacity), PBI Projects, 2015



Thus, there is evidence that operators of some of these PBI projects prioritized dispatch for demand charge minimization, especially in the summer. We cannot, however, make any generalizations to the larger population due to the small sample size.

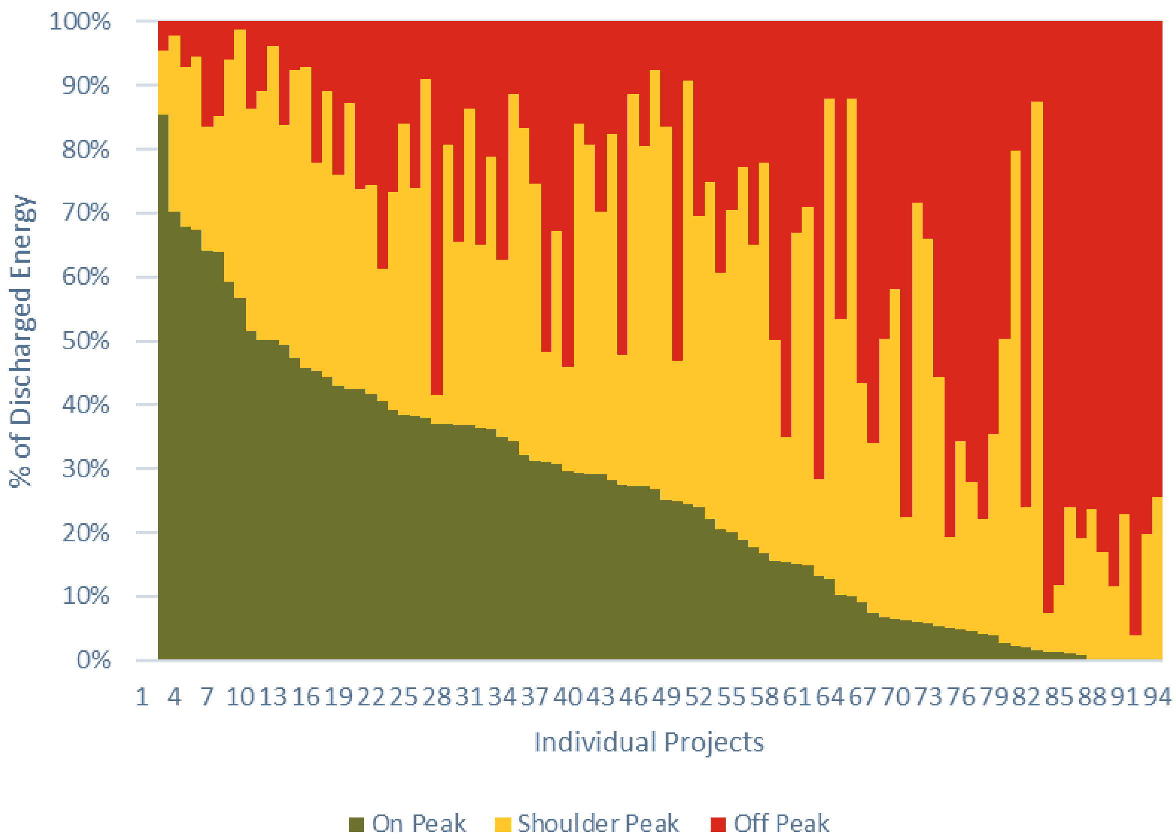
Non-PBI Projects

The percentage of discharge energy by summer TOU period for non-PBI projects is shown in Figure 6-16.

Thirty-two of the non-PBI projects (34%) have 35% or more of their discharged energy on peak, suggesting that they may be engaging in rate arbitrage. On the other hand, we can conclude that many customers are *not* prioritizing rate arbitrage: 17 projects (18%) discharge 70% or more of their energy *off-peak*. This may be because many rate schedules with demand charges include a cost component based on the maximum monthly power, regardless of the timing of that maximum.

For the projects that do not display these extremes, it is not possible to say with any certainty whether project operators are prioritizing rate arbitrage, but this analysis suggests that this is not the primary driver behind their behavior. Fifty-seven projects have an on-peak discharge percentage *below* 35% and a high discharge day percentage *under* 15%. Fifty-two projects have an on-peak percentage below 35% and a capacity factor below 15%. Fifty projects feature all three of these characteristics. This constitutes a significant number of observed projects for which it is difficult to discern a dominant behavioral model.

Figure 6-16: Non-PBI Project Discharge by Assumed TOU Period, 2015 (no 2014 data available)

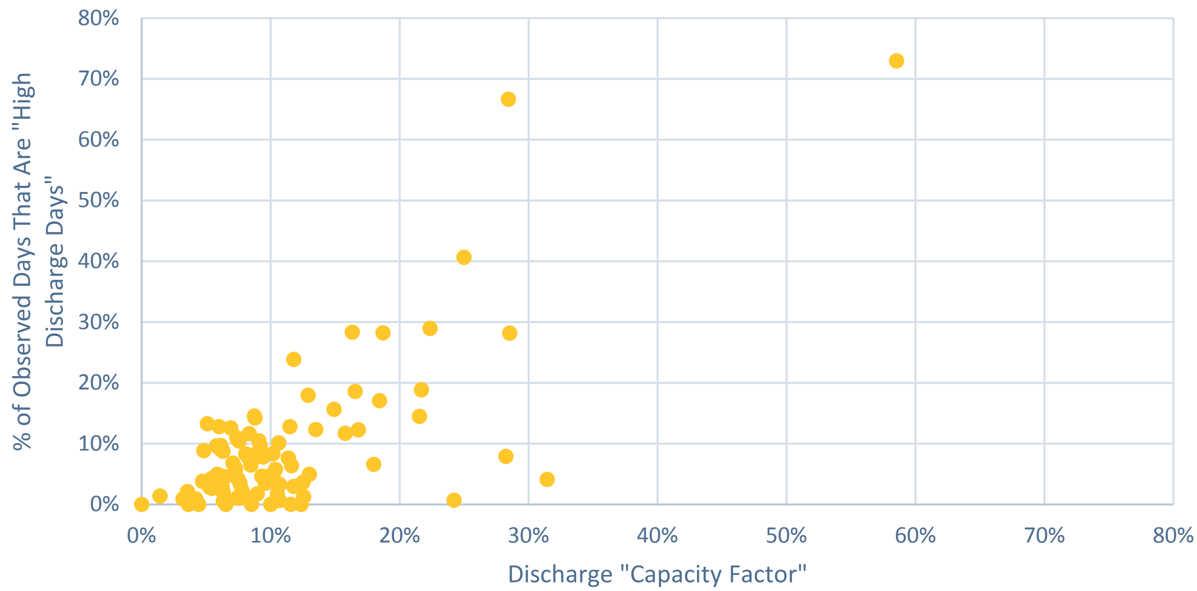


We calculated an additional metric designed to analyze customer discharge behavior in the absence of load data: percentage of 'high discharge days.' This is defined as the number of days where a project was discharged at 20% or more of its rebated capacity, divided by the total days of data available for the project.

This metric provides some further insights in addition to the capacity factor metric alone. While a storage project may attain a given capacity factor by consistently discharging at a lower power, it may also produce the same capacity factor statistic with infrequent bursts of high power output, followed by more sustained periods of little to no discharging. Figure 6-17 shows these two metrics for each non-PBI, non-residential storage project in our sample.[12]

[12] High discharge day percentages incorporate all days in a system's data set (as opposed to weekdays only).

Figure 6-17: Percent of "High Discharge Days" as a function of Capacity Factor, Non-PBI Non-Residential Projects, 2015 (no 2014 data available)



Only 21% of non-PBI non-residential projects appear to have been consistently discharging their batteries to a significant extent in 2015. The vast majority (79%) have discharge "Capacity Factors" less than 15% and have fewer than 15% "High Discharge Days;" these are characterized as being used infrequently and at low capacity.[13]

Pre-programmed/Timed Dispatch

There are several projects that do not fit cleanly into any of the above characterizations. While it is difficult to discern exactly what may be happening with these projects, one general explanation for non-intuitive data would be that the given project is working on a timer or some kind of pre-programming and is thus non-responsive to incentives like rate arbitrage or peak demand reduction.

Residential Projects

Due to poor accuracy in the charging and discharging data for residential projects, we are not able to evaluate TOU rate arbitrage or demand charge reduction behavior with confidence. However, the latter is unlikely since California does not currently have residential demand charges.

[13] Given that the sole storage vendor that provided non-PBI project data included in this report anonymized the data, it is not be possible to match these projects with load data, so we are not able to conclusively say anything further about the dispatch behavior of those projects.

6.5 Timing of Battery Activity

In addition to attempting to characterize the dispatch behavior of individual storage projects, we performed analyses to understand aggregated battery dispatch.

Non-Residential Projects

Figure 6-18 shows the aggregate kWh of energy in each month-hour, normalized for the kW of battery capacity rebated. Note that **discharging is shown as positive values in green** and **charging as negative values in red**.

Note that only 4 non-residential projects are paired with PV, and we do not factor PV generation into this analysis.

As mentioned above, the data was extremely sparse for 2014, featuring only two (PBI) projects. With this significant caveat, we note that discharging is sparse in this year, occurring in the morning and afternoon, with charging occurring overnight.

Figure 6-18: Total kWh of Discharge (Charge) per kW Rebated Capacity, 2014

		1	2	3	4	5	6	7	8	9	10	11	12
	0	-0.04	-0.01	0.05	-0.12	-0.31	-0.54	-0.57	-0.14	-0.18	-0.13	0.00	0.00
	1	-0.04	-0.01	-0.29	-0.14	-0.31	-0.50	-0.30	-0.14	-0.18	-0.12	0.00	0.00
	2	0.00	-0.01	-0.61	-0.21	-0.31	-0.33	-0.10	-0.08	-0.15	-0.11	0.00	0.00
	3	0.00	-0.01	-0.68	-0.23	-0.22	-0.31	-0.08	-0.07	-0.14	-0.10	0.00	-0.01
	4	0.00	-0.01	-0.30	-0.08	-0.11	-0.15	-0.06	-0.06	-0.09	-0.08	0.00	-0.01
	5	-0.01	-0.01	0.63	0.19	-0.06	-0.06	-0.05	-0.04	-0.06	-0.06	0.00	-0.01
	6	0.00	-0.01	0.91	0.31	0.16	0.17	0.18	0.04	-0.04	-0.04	0.00	-0.01
	7	0.00	-0.01	0.11	0.22	0.07	0.01	0.17	-0.02	-0.04	-0.01	0.00	-0.01
	8	0.00	-0.01	0.02	0.53	0.32	0.48	0.59	0.13	-0.03	-0.01	0.00	-0.01
	9	0.00	-0.01	-0.18	-0.18	-0.42	-0.38	0.03	-0.19	0.04	0.03	0.00	-0.01
H	10	0.00	-0.01	0.22	0.14	-0.21	-0.38	0.29	0.06	0.07	0.05	0.00	0.00
o	11	0.00	-0.01	0.00	0.23	0.73	0.97	0.10	0.05	0.11	0.07	0.00	0.00
u	12	0.00	-0.01	0.19	-0.04	0.36	0.56	0.45	0.16	0.11	0.11	0.00	0.00
r	13	0.00	-0.01	-0.06	-0.11	0.08	0.32	0.46	0.16	0.08	0.01	0.00	-0.01
	14	0.00	-0.01	-0.17	-0.32	-0.09	0.22	0.42	0.05	0.10	0.06	0.00	-0.01
	15	0.00	0.00	-0.29	-0.43	-0.05	-0.13	-0.13	0.00	0.07	0.06	0.00	-0.01
	16	0.00	-0.01	-0.24	-0.14	-0.18	-0.19	0.09	0.01	0.05	0.06	0.00	0.00
	17	-0.01	-0.01	0.11	-0.20	-0.04	0.06	-0.13	-0.01	0.05	0.02	0.00	0.00
	18	0.00	-0.01	-0.15	-0.09	-0.06	0.04	-0.13	0.00	0.05	0.02	0.00	0.00
	19	-0.01	-0.01	-0.23	-0.19	-0.02	-0.03	-0.56	-0.06	0.04	-0.03	0.00	0.00
	20	0.00	-0.01	-0.12	-0.28	-0.07	-0.34	-0.62	-0.12	-0.05	-0.05	0.00	0.00
	21	0.00	-0.01	-0.29	-0.30	-0.11	-0.61	-0.72	-0.11	-0.07	-0.05	0.00	0.00
	22	0.00	-0.01	-0.15	-0.11	-0.21	-0.47	-0.59	-0.14	-0.15	-0.11	0.00	0.00
	23	0.00	-0.01	0.02	-0.16	-0.28	-0.61	-0.65	-0.14	-0.17	-0.11	0.00	0.00

2015, with its richer dataset, reveals a much more intuitive distribution of charging and discharging behavior. See Figure 6-20.

For PBI projects, charging occurred predominantly overnight and discharging occurred consistently in the late afternoon and all evening. In addition, there seems to be a slight trend for increased activity later in the year. Note that these figures are normalized for kW rebated, so the addition of storage projects throughout the year does not contribute to this observed pattern. The seemingly heavier battery usage in later months is due to differences in storage dispatch behavior based on installation date.

Figure 6-19 shows, for each PBI project, discharge capacity factor as a function of the first date of available data in our sample. As shown in the figure, storage projects installed in 2014 have low capacity factors relative to projects installed in 2015. That is, there is a general increase in cycling of batteries the later into 2015 that they come online. However, there does not seem to be a clear trend of individual projects changing dispatch algorithms over time. Providers of this nascent technology may still be optimizing the dispatch algorithms, so dispatch behavior and performance over time may continue to evolve.

Figure 6-19: 2015 Discharge Capacity Factor versus Date of First Available Data Point, PBI Projects

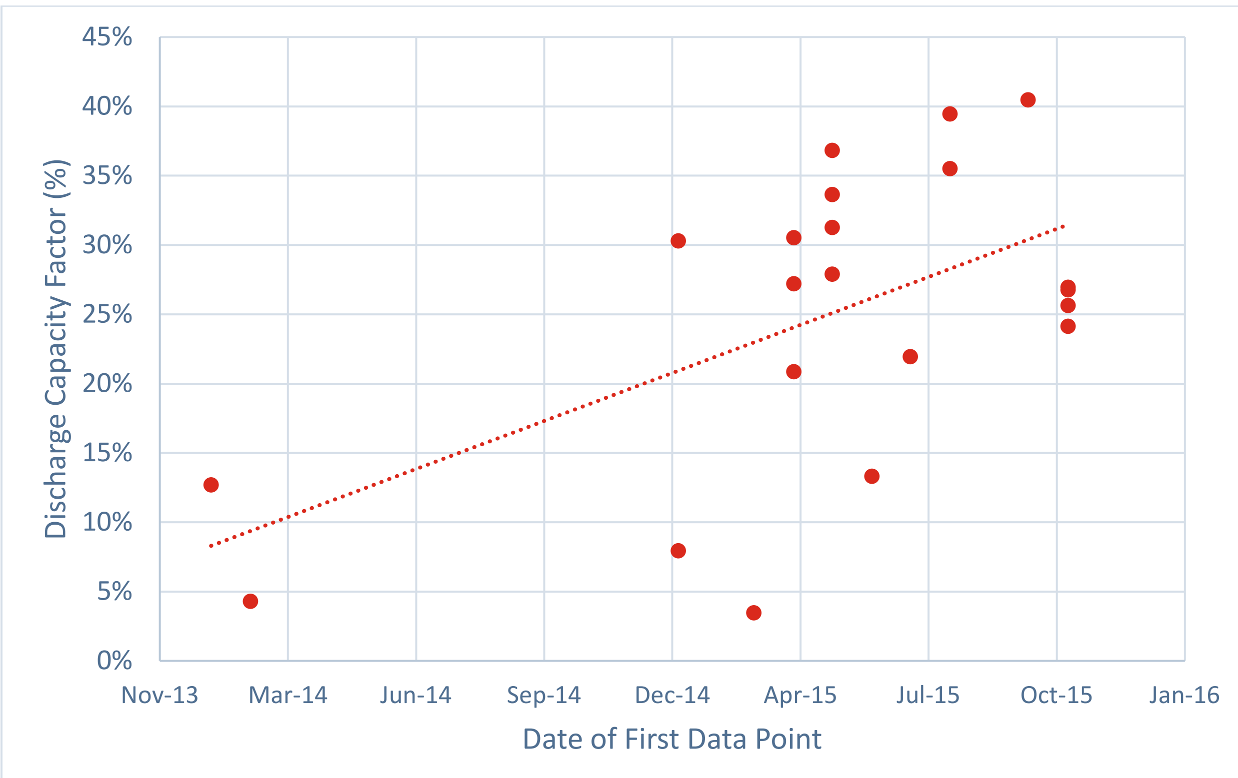


Figure 6-20: Total kWh of Discharge (Charge) per kW Rebated Capacity, PBI Projects, 2015[14]

		1	2	3	4	5	6	7	8	9	10	11	12
	0	-0.05	-0.29	-0.39	-0.54	-0.94	-1.35	-1.43	-1.65	-1.63	-1.49	-1.18	-1.07
	1	-0.04	-0.27	-0.31	-0.40	-0.56	-0.91	-0.73	-1.15	-1.14	-1.23	-1.55	-1.18
	2	-0.04	-0.26	-0.28	-0.33	-0.19	-0.39	-0.18	-0.66	-0.56	-0.77	-1.27	-1.07
	3	-0.04	-0.22	-0.22	-0.30	-0.07	-0.15	-0.11	-0.43	-0.31	-0.57	-0.79	-0.76
	4	-0.04	-0.14	-0.19	-0.23	-0.05	-0.09	-0.06	-0.26	-0.16	-0.37	-0.59	-0.56
	5	-0.03	-0.08	-0.18	-0.16	-0.03	-0.05	-0.04	-0.18	-0.11	-0.37	-0.45	-0.47
	6	-0.02	-0.03	-0.13	-0.11	-0.02	-0.03	-0.02	-0.12	-0.07	-0.27	-0.39	-0.39
	7	-0.01	0.00	-0.04	0.01	-0.02	0.00	-0.01	-0.01	-0.03	-0.17	-0.28	-0.31
	8	-0.01	0.05	-0.01	0.12	-0.01	0.03	0.00	0.07	0.03	-0.02	-0.12	-0.16
	9	0.01	0.07	-0.01	0.03	0.00	0.03	-0.05	-0.01	-0.02	0.08	0.02	-0.01
H	10	0.00	0.07	-0.01	0.03	0.02	0.06	-0.01	0.07	0.04	-0.02	0.06	0.00
o	11	-0.01	0.08	0.06	0.09	0.13	0.22	0.03	0.21	0.18	0.16	0.24	0.15
u	12	-0.01	0.07	0.11	0.09	0.12	0.37	0.08	0.29	0.20	0.23	0.28	0.27
r	13	0.02	0.07	0.10	0.09	0.14	0.44	0.11	0.26	0.24	0.20	0.28	0.16
	14	-0.01	0.09	0.12	0.20	0.36	0.52	0.25	0.39	0.31	-0.17	-0.08	-0.22
	15	-0.02	0.10	0.14	0.27	0.62	0.65	0.68	0.82	0.48	-0.17	-0.06	0.07
	16	0.04	0.16	0.16	0.23	0.60	0.46	0.63	1.12	0.39	-0.10	0.01	-0.09
	17	0.02	0.21	0.24	0.21	0.20	0.12	0.14	0.54	0.17	0.11	0.02	-0.03
	18	0.00	0.18	0.24	0.21	0.18	0.17	0.26	0.53	0.88	1.23	0.44	0.28
	19	0.01	0.14	0.17	0.12	0.19	0.26	0.48	0.68	1.06	1.51	1.58	1.34
	20	-0.01	0.03	0.08	0.03	0.13	0.23	0.38	0.56	0.75	1.42	1.68	1.50
	21	-0.01	-0.12	-0.11	-0.16	-0.57	-0.65	-0.72	-1.13	-0.97	-0.64	0.99	1.26
	22	-0.05	-0.31	-0.20	-0.17	-0.45	-0.31	-0.08	-0.40	-0.49	-0.10	-0.71	-0.59
	23	-0.05	-0.29	-0.30	-0.38	-0.94	-1.01	-0.98	-1.62	-1.31	-1.06	-0.11	-0.20

On the other hand, the non-PBI, non-residential projects show little to no structure in charging pattern, as shown in Figure 6-21. This could be due to customers attempting to reduce their demand charges, where peak demand may occur during any hour of the day.[15] We see that, in aggregate, the non-PBI projects are net charging in all but one month-hour of 2015. This is due to a combination of very low roundtrip efficiencies and a diversified usage profile (that is, there is little synchronization across the projects in terms of when to charge or discharge),

14 Again, these figures are normalized for rebated kW of capacity, so the steady increase in discharge magnitude is not due to an increase in projects. Upon inspection, we found a correlation between how late into 2015 a project went online and its discharge capacity factor.

15 As mentioned at a recent conference, one hotel that installed AES had peak demand spikes every other Friday shortly after noon. These spikes were due to employees using the elevators to go to the basement to pick up their paychecks. Therefore, the AES might only significantly discharge every two weeks but could have a substantial impact on the customer's electricity bill.

Figure 6-21: Total kWh of Discharge (Charge) per kW Rebated Capacity, Non-PBI Non-Residential Projects, 2015

	Month											
Hour	1	2	3	4	5	6	7	8	9	10	11	12
0	-0.12	-0.10	-0.11	-0.07	-0.12	-0.14	-0.12	-0.18	-0.10	-0.09	-0.08	-0.08
1	-0.18	-0.09	-0.14	-0.10	-0.08	-0.08	-0.06	-0.12	-0.07	-0.07	-0.12	-0.15
2	-0.06	-0.12	-0.10	-0.09	-0.11	-0.05	-0.04	-0.13	-0.06	-0.10	-0.13	-0.18
3	-0.13	-0.13	-0.10	-0.12	-0.16	-0.03	-0.06	-0.10	-0.05	-0.07	-0.09	-0.14
4	-0.19	-0.23	-0.05	-0.15	-0.16	0.00	-0.04	-0.05	-0.05	-0.06	-0.09	-0.13
5	-0.27	-0.15	-0.07	-0.13	-0.10	-0.13	-0.16	-0.20	-0.08	-0.09	-0.12	-0.16
6	-0.30	-0.04	-0.09	-0.05	-0.12	-0.08	-0.09	-0.14	-0.07	-0.04	-0.10	-0.09
7	-0.19	-0.06	-0.12	-0.13	-0.15	-0.11	-0.10	-0.15	-0.09	-0.05	-0.12	-0.13
8	-0.32	-0.18	-0.21	-0.23	-0.25	-0.28	-0.25	-0.23	-0.14	-0.11	-0.11	-0.17
9	-0.23	-0.28	-0.18	-0.22	-0.19	-0.31	-0.27	-0.24	-0.12	-0.11	-0.14	-0.12
10	-0.19	-0.23	-0.29	-0.32	-0.23	-0.31	-0.23	-0.31	-0.17	-0.15	-0.06	-0.04
11	-0.26	-0.17	-0.35	-0.32	-0.37	-0.32	-0.31	-0.36	-0.21	-0.22	-0.04	0.00
12	-0.21	-0.01	-0.14	-0.07	-0.12	-0.24	-0.20	-0.16	-0.07	-0.02	-0.03	-0.05
13	-0.33	-0.32	-0.29	-0.29	-0.21	-0.35	-0.26	-0.15	-0.11	-0.06	-0.15	-0.13
14	-0.20	-0.08	-0.15	-0.06	-0.11	-0.13	-0.12	-0.34	-0.29	-0.30	-0.13	-0.14
15	-0.22	-0.31	-0.29	-0.27	-0.25	-0.29	-0.28	-0.33	-0.25	-0.28	-0.25	-0.25
16	-0.16	-0.20	-0.22	-0.24	-0.25	-0.24	-0.19	-0.28	-0.23	-0.26	-0.22	-0.28
17	-0.10	-0.02	-0.11	-0.11	-0.16	-0.14	-0.11	-0.20	-0.14	-0.18	-0.17	-0.20
18	-0.17	-0.12	-0.16	-0.17	-0.18	-0.18	-0.19	-0.20	-0.15	-0.18	-0.16	-0.15
19	-0.18	-0.23	-0.19	-0.24	-0.18	-0.20	-0.17	-0.16	-0.13	-0.16	-0.15	-0.13
20	-0.15	-0.11	-0.12	-0.16	-0.14	-0.14	-0.15	-0.12	-0.12	-0.13	-0.11	-0.11
21	-0.15	-0.10	-0.12	-0.14	-0.14	-0.14	-0.12	-0.20	-0.12	-0.12	-0.11	-0.11
22	-0.15	-0.09	-0.12	-0.12	-0.12	-0.12	-0.12	-0.23	-0.11	-0.11	-0.10	-0.09
23	-0.15	-0.11	-0.10	-0.11	-0.14	-0.13	-0.13	-0.16	-0.10	-0.08	-0.05	-0.03

Given that the PBI projects have much higher capacities than the non-PBI projects, the aggregated timing of the charge/discharge behavior much more closely resembles the PBI projects than the non-PBI projects. See Figure 6-22.

Figure 6-22: Total kWh of Discharge (Charge) per kW Rebated Capacity, All Observed non-Residential Projects, 2015

	Month											
Hour	1	2	3	4	5	6	7	8	9	10	11	12
0	-0.05	-0.27	-0.35	-0.48	-0.83	-1.18	-1.22	-1.43	-1.34	-1.26	-1.02	-0.93
1	-0.06	-0.25	-0.28	-0.36	-0.50	-0.79	-0.62	-1.00	-0.94	-1.04	-1.34	-1.03
2	-0.04	-0.24	-0.25	-0.29	-0.18	-0.34	-0.15	-0.58	-0.47	-0.66	-1.11	-0.94
3	-0.05	-0.21	-0.20	-0.28	-0.08	-0.13	-0.11	-0.38	-0.26	-0.49	-0.69	-0.67
4	-0.06	-0.15	-0.17	-0.22	-0.07	-0.08	-0.06	-0.23	-0.14	-0.32	-0.52	-0.50
5	-0.05	-0.09	-0.17	-0.15	-0.04	-0.06	-0.06	-0.18	-0.11	-0.32	-0.40	-0.43
6	-0.04	-0.03	-0.12	-0.10	-0.04	-0.04	-0.03	-0.12	-0.07	-0.23	-0.35	-0.35
7	-0.03	-0.01	-0.05	-0.01	-0.03	-0.02	-0.02	-0.03	-0.05	-0.15	-0.26	-0.29
8	-0.03	0.02	-0.04	0.07	-0.04	-0.02	-0.04	0.03	0.00	-0.04	-0.11	-0.16
9	-0.01	0.04	-0.04	0.00	-0.03	-0.02	-0.09	-0.04	-0.04	0.05	0.00	-0.02
10	-0.02	0.04	-0.05	-0.02	-0.01	0.00	-0.05	0.01	0.00	-0.04	0.04	-0.01
11	-0.03	0.05	0.00	0.03	0.06	0.14	-0.02	0.13	0.10	0.10	0.20	0.13
12	-0.03	0.06	0.07	0.07	0.09	0.28	0.03	0.23	0.14	0.19	0.24	0.23
13	-0.02	0.03	0.05	0.03	0.10	0.33	0.05	0.20	0.17	0.16	0.22	0.12
14	-0.03	0.08	0.08	0.16	0.30	0.43	0.19	0.28	0.19	-0.19	-0.09	-0.21
15	-0.04	0.06	0.07	0.19	0.51	0.52	0.52	0.65	0.34	-0.18	-0.09	0.02
16	0.02	0.12	0.12	0.18	0.50	0.38	0.52	0.91	0.30	-0.12	-0.02	-0.11
17	0.01	0.19	0.20	0.18	0.16	0.09	0.11	0.42	0.12	0.07	-0.01	-0.06
18	-0.02	0.15	0.19	0.17	0.14	0.13	0.20	0.42	0.72	1.03	0.36	0.22
19	-0.01	0.10	0.12	0.08	0.15	0.21	0.40	0.56	0.88	1.27	1.33	1.13
20	-0.02	0.01	0.05	0.01	0.10	0.18	0.31	0.46	0.61	1.20	1.43	1.27
21	-0.03	-0.11	-0.12	-0.16	-0.51	-0.59	-0.64	-0.99	-0.84	-0.57	0.83	1.07
22	-0.06	-0.29	-0.19	-0.17	-0.41	-0.28	-0.08	-0.38	-0.43	-0.11	-0.62	-0.52
23	-0.05	-0.27	-0.28	-0.35	-0.84	-0.90	-0.87	-1.40	-1.13	-0.92	-0.10	-0.18

Residential Projects

All residential projects for which we have data were paired with PV projects. Not surprisingly, we see a correlation between battery charging behavior and solar generation output – compare the red in charging hours in Figure 6-23 with the red solar generation hours in Figure 6-24. Similarly, notice that the battery projects see consistent discharge during late afternoon summer days. Nearly all the residential projects we received data for are located within the same IOU service territory, and these summer late afternoon hours correspond with that utility's higher time of use rate, boxed in Figure 6-23 below.

Figure 6-23: Total kWh of Discharge (Charge) per kW Rebated Capacity, Residential Projects, 2015

		Month											
		1	2	3	4	5	6	7	8	9	10	11	12
Hour	0	-0.28	-0.25	-0.28	-0.25	-0.26	-0.26	-0.28	-0.29	-0.29	-0.29	-0.24	-0.26
	1	-0.28	-0.25	-0.28	-0.25	-0.26	-0.26	-0.29	-0.29	-0.29	-0.29	-0.24	-0.26
	2	-0.28	-0.27	-0.28	-0.25	-0.26	-0.26	-0.29	-0.29	-0.29	-0.29	-0.25	-0.26
	3	-0.28	-0.25	-0.28	-0.25	-0.26	-0.26	-0.29	-0.30	-0.29	-0.29	-0.25	-0.27
	4	-0.29	-0.25	-0.28	-0.25	-0.26	-0.26	-0.29	-0.30	-0.29	-0.29	-0.26	-0.27
	5	-0.28	-0.25	-0.28	-0.25	-0.27	-0.27	-0.29	-0.30	-0.29	-0.29	-0.26	-0.27
	6	-0.28	-0.25	-0.28	-0.32	-0.50	-0.54	-0.48	-0.37	-0.30	-0.29	-0.26	-0.28
	7	-0.28	-0.26	-0.44	-0.78	-1.10	-0.94	-0.97	-0.79	-0.61	-0.44	-0.30	-0.28
	8	-0.31	-0.62	-1.47	-2.25	-2.59	-2.20	-2.19	-2.05	-2.00	-1.84	-1.12	-0.50
	9	-1.50	-2.17	-3.65	-3.30	-2.73	-3.06	-3.77	-3.91	-3.87	-4.08	-3.42	-1.89
	10	-2.90	-2.85	-1.71	-0.64	-0.47	-2.05	-2.95	-2.88	-3.16	-3.47	-5.18	-3.07
	11	-1.60	-0.46	-0.31	-0.45	-0.31	-2.14	-3.58	-3.29	-3.42	-2.92	-6.04	-2.36
	12	-1.05	-0.33	-0.29	-0.44	-0.35	-2.05	-4.01	-3.53	-3.76	-2.30	-5.95	-2.04
	13	-0.72	-0.67	-0.36	-0.24	-0.37	-1.65	-3.81	-3.32	-3.24	-1.10	-3.23	-1.31
	14	-0.82	-0.45	-0.56	-0.74	-0.83	-0.88	-1.63	-1.12	-1.22	-0.17	-0.56	-0.89
	15	-0.42	-0.44	-0.72	-0.50	-0.40	-0.61	-1.18	-0.56	-0.68	0.17	1.08	-0.55
	16	-0.63	-0.55	-0.33	-0.36	-0.50	1.39	4.19	3.46	4.28	1.41	1.80	-0.07
	17	-0.47	-0.52	-0.56	-0.55	-0.62	2.01	4.44	3.81	3.78	1.53	2.93	0.25
	18	-0.22	-0.30	-0.48	-0.43	-0.50	2.79	4.54	3.56	3.25	1.62	3.30	0.26
	19	-0.22	-0.21	-0.27	-0.31	-0.39	-0.47	-0.53	-0.42	-0.19	0.55	2.89	0.24
	20	-0.24	-0.23	-0.27	-0.25	-0.26	-0.23	-0.25	-0.25	-0.24	-0.29	2.27	0.24
	21	-0.27	-0.25	-0.27	-0.25	-0.26	-0.23	-0.25	-0.27	-0.27	-0.29	-0.23	-0.23
	22	-0.28	-0.25	-0.27	-0.25	-0.26	-0.24	-0.27	-0.28	-0.27	-0.29	-0.24	-0.24
	23	-0.28	-0.25	-0.27	-0.25	-0.26	-0.25	-0.28	-0.29	-0.28	-0.29	-0.24	-0.25

Figure 6-24: Total kWh of Solar Output, Residential Projects, 2015

						Month						
Hour	1	2	3	4	5	6	7	8	9	10	11	12
0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5	0.00	0.00	0.00	0.04	1.37	5.22	1.24	0.04	0.00	0.00	0.00	0.00
6	0.00	0.00	0.72	33.84	132.22	160.17	117.25	45.73	6.02	0.56	0.01	0.00
7	0.43	3.61	89.60	302.35	492.07	402.76	412.66	305.38	198.64	89.79	13.29	1.20
8	70.69	240.20	738.17	1209.20	1426.98	1221.52	1205.92	1113.81	1065.01	960.35	516.22	120.95
9	751.56	1175.95	2077.80	1920.67	1643.83	1847.94	2238.92	2284.08	2249.48	2366.15	1940.27	1003.33
10	1681.15	1725.66	1089.06	502.17	435.73	1317.05	1854.55	1778.56	1934.10	2156.00	3044.13	1750.61
11	1211.06	585.37	431.15	494.85	436.46	1423.47	2274.63	2061.77	2124.16	1936.95	3624.31	1389.51
12	1054.19	545.29	499.39	554.83	508.31	1406.07	2567.07	2226.06	2360.23	1648.94	3687.04	1304.05
13	977.38	704.08	544.40	563.56	604.52	1257.41	2527.71	2148.21	2112.89	1082.45	2411.80	976.69
14	1031.63	629.47	716.49	832.44	918.46	895.37	1362.99	981.09	1061.76	774.02	1316.87	789.36
15	664.60	582.05	780.99	706.62	680.45	740.71	1084.70	643.98	748.22	786.27	736.53	613.50
16	526.38	519.67	478.07	511.51	633.21	795.12	448.78	433.37	374.86	594.82	412.73	351.38
17	247.94	341.06	416.54	451.67	548.50	458.04	405.89	341.22	354.30	356.38	150.26	97.80
18	13.75	111.18	238.62	266.92	336.40	310.78	331.93	285.48	217.36	60.59	0.91	0.25
19	0.00	0.19	18.75	98.44	180.85	246.09	279.27	177.88	23.03	0.02	0.00	0.00
20	0.00	0.00	0.00	0.11	7.08	35.61	30.37	2.88	0.00	0.00	0.00	0.00
21	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
22	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

6.6 Coincident Peak Impacts

One important opportunity for storage projects to create value for the electricity grid lies in their ability to shift load from peak system hours to hours when demand is lower.[16] Discharging storage during peak system hours creates value by reducing peak system demand, thereby avoiding generation capacity and/or transmission and distribution capacity costs.

We therefore sought to determine the effect of SGIP storage projects on system-wide[17] demand during system peak hours in 2014 and 2015. To measure this effect, we determined the aggregate net discharge from the sampled storage projects in the peak 200 hours of the year (2014 or 2015) and compared this to the average discharge over all summer hours. We defined summer as June through October, inclusive. This average summer net discharge metric provides important context for understanding the net discharge during system peak hours. Since there are losses associated with storage dispatch, storage projects charge more than they discharge, which results in net charging in aggregate. Thus, average summer net discharge provides a better comparison point than zero net discharge for assessing deviations in storage behavior during peak system demand.

It is important to note that the impacts described here are those that accompany observed 2015 discharge behavior, and that further incentivizing storage projects to optimize their charging behavior to minimize

16 'System' in Section 6 refers to the CAISO system as a whole.

17 All peak system loads hours in 2014 and 2015 occurred during the 'summer' timeframe in California.

coincident peak impacts could produce different results in the future. See Section 6.7 – 'Looking Ahead'- for additional thoughts on policy interventions that could achieve this aim.

Non-residential Projects

2014

The results observed for the two 2014 PBI projects varied significantly depending on which portion of the system's top 200 demand hours were being observed. In the system's top 50 hours of peak demand, the two PBI projects showed a relatively large benefit, discharging at an average of 12 kW (compared to their average over the summer rate of -30 kW). However, this benefit was reduced sharply by the projects' behavior in the remainder of the year's top 200 hours:,the top 51-100, 101-150, 151-200 top system hours showed average discharges of 3 kW, 2 kW and -2 kW, respectively for the two customers. That is, in the top 151 to 200 peak demand hours on the system, the two PBI projects observed were actually *charging (or consuming energy and increasing demand)*, on average.

The available sample of two 2014 projects was insufficiently robust to scale these results to population impacts.

2015

Our coincident peak impact findings for 2015 are summarized in Figure 6-25 (PBI projects) and Figure 6-26 (non-PBI projects) below. The bars on the left show the average net discharge during each bucket of top system peak hours. As described above, the summer average bar provides useful context. Since there are losses associated with storage dispatch, storage projects charge more than they discharge on net. Average charge over the summer period provides a better comparison point than zero net discharge for assessing deviations in storage behavior during peak system demand.

Both PBI and non-PBI, non-residential storage projects showed much lower negative consumption impacts in all of the top 200 system hours of 2015 than they did on average during the summer. That is, non-residential storage customers are at least somewhat avoiding charging during peak hours. However, while the PBI projects showed a net discharge during peak hours - reducing demand and benefiting the grid - the non-PBI customers were, in aggregate, charging during the top 200 hours of 2015. This implies that the incentives to avoid charging during peak hours may be insufficient, and that there is a significant opportunity to make better use of these projects from a grid-level perspective.

Figure 6-25: Average Net Discharge - Top 200 System Peak Hours, of Observed PBI Projects, 2015

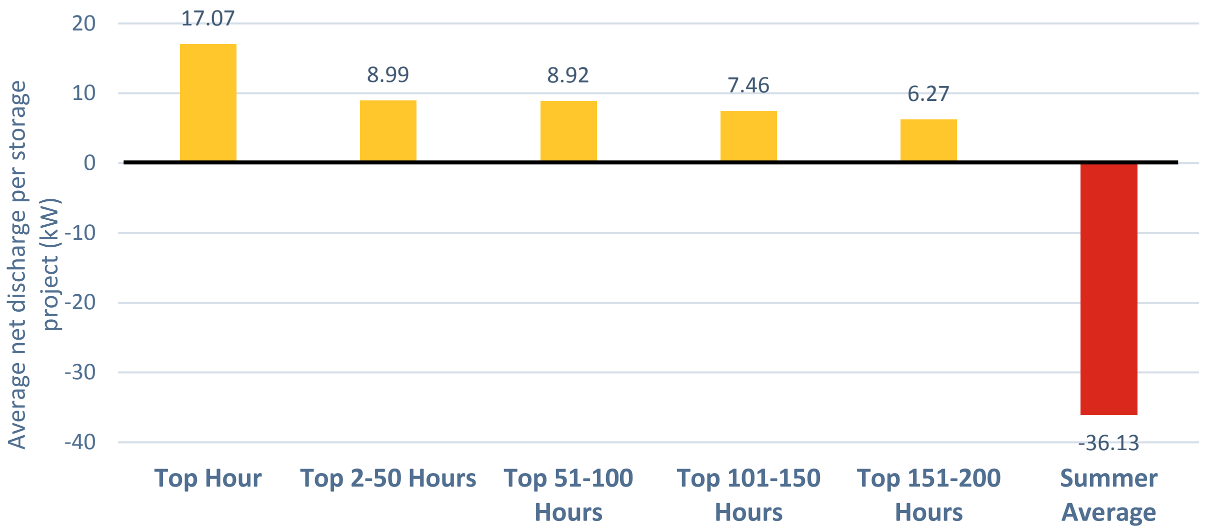
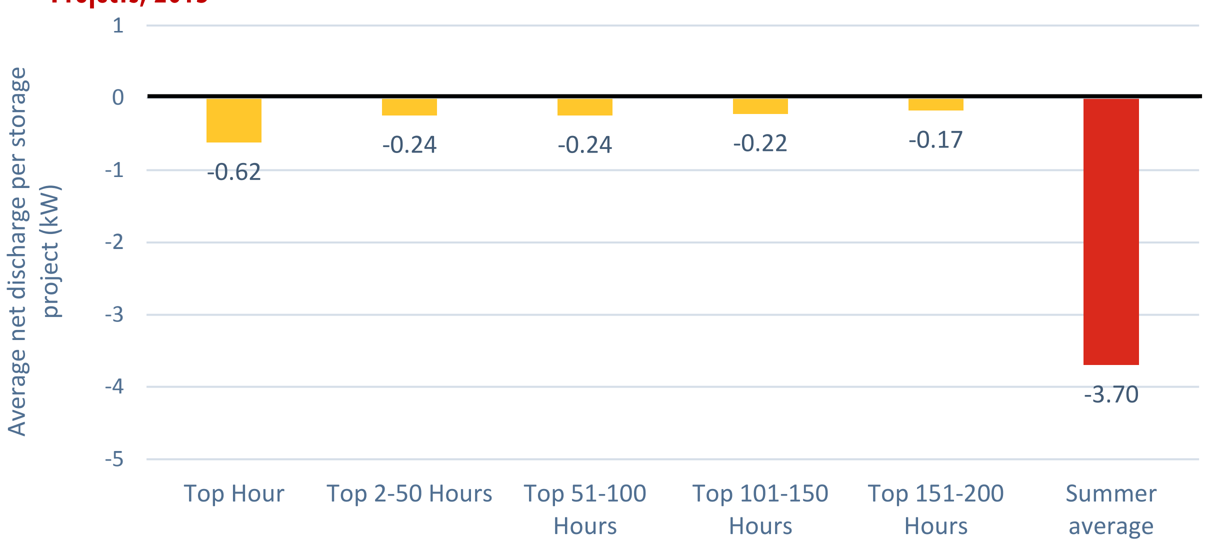
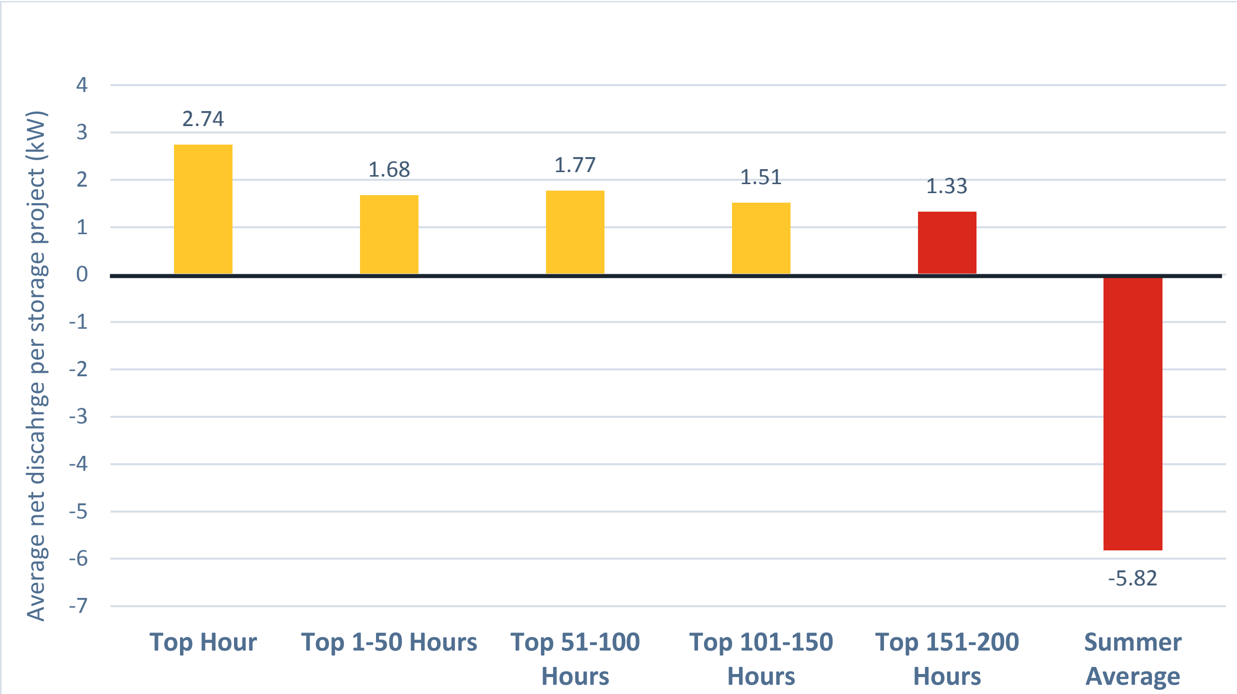


Figure 6-26: Average Net Discharge - Top 200 System Peak Hours, of Observed Non-PBI Non-Residential Projects, 2015



Though the non-PBI, non-residential projects charged, in aggregate, during the system's 2015 peak hours, the rebated capacity across the PBI projects is much larger. Thus, the aggregated behavior across the two customer classes was net discharging in all the top hour buckets. See Figure 6-27 for more details.

Figure 6-27: Average Net Discharge - Top 200 System Peak Hours, of All Observed Non-Residential Projects, 2015



Extending Sample to Population

We were able to use the total kW of rebated capacity shown in Table 6-1, Table 6-2, Table 6-3 and Table 6-4 to extend our sample estimate of 2015 system peak impacts to the full set of PBI and non-residential, non-PBI projects in the SGIP program. We achieved this by first determining a de-rated capacity for each observed project, based on the proportion of 2015 for which a given project was interconnected. That is, if a given project was only on-line for the second half of the year, the project's de-rated capacity was calculated as 50% of its rebated capacity. We then determined an *average* de-rate percentage per MW of rebated capacity across the set of observed projects (calculated separately for PBI and non-PBI projects). Next, we created a distribution of the net kW of discharge per kW of de-rated capacity in each of four 'top hour' bins: the top 1 – 50, 51 – 100, 101 – 150, and 151 – 200 CAISO system load hours during each year (2014 and 2015). Finally, we used the proportion of MW of rebated capacity in our sample to program-wide rebated MW and the average de-rate scalar to convert to a program-wide estimate of kW net discharge during top demand hours.

The population-level estimates are summarized in Figure 6-28 and range from 161 to 235 kW. As these are based directly on the sample information, we see, generally, a proportional relationship between the top hour bins described above and the summer average. Even the non-PBI projects, which tend to charge in top hours, have dramatically different behavior in top system demand hours than during the rest of the summer.

Figure 6-28: Estimate of Population-Level System Peak Impacts, Compared to Summer Average, Non-Residential Storage Projects, 2015[18]

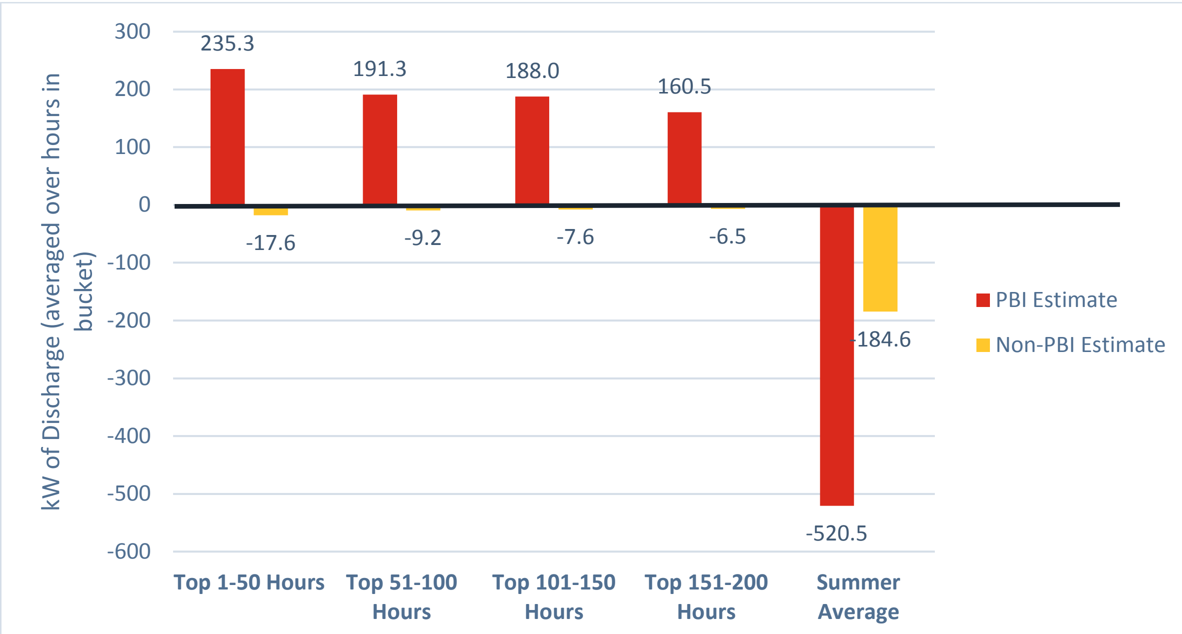


Table 6-6 shows the Average Net Discharge, by PA, during each of the peak system hour 'buckets.' This is shown in kW, with % of rebated capacity in parentheses below. Net charging appears as a negative number.

We estimate a large difference in total contribution to the CAISO system coincident peak by PA in 2015. For example, we estimate that PG&E's population of PBI storage projects contributed 204.8kW of net discharge, on average, to the top 50 CAISO load hours in 2015. SCE's projects, on the other hand, contributed only 26.8kW. However, the amount of SGIP storage capacity in both our sample and the population also varies greatly by PA: in particular, the vast majority of SGIP storage projects installed by the end of 2015 are administered by PG&E. Therefore, this average does not provide a clear picture of per-kW differences between PAs.

To better parse coincident peak impacts, we calculated a second metric that describes the system coincident peak impact of each *kW* of rebated capacity, by PA. This metric is calculated as the average net discharge across the PBI (or non-PBI) projects administered by a given PA, divided by the average amount of rebated capacity across the PBI (or non-PBI) projects administered by a given PA in each system peak hour. This metric is shown as (%) in the lower half of each cell of Table 6-6. As an example, PG&E PBI projects show an average net discharge of 204.8 kW in the top 50 CAISO system load hours of 2015. In our sample, over these same top 50 hours, we see an average of 6,300 kW of rebated capacity administered by PG&E. Thus, the statistic reported in parentheses in this cell is 204.8 kW/6,300 kW = 3%.

[18] Summer Average was calculated by taking an average of the sample projects observed over the summer months, weighted by the number of days in each month and dividing this by the total number of customers in the sample to produce an average percent of projects online in the summer. This percentage was then multiplied by the number of projects in the population and the above "per customer" averages to produce a population-wide estimate.

This metric is useful for comparing the impact of each PA's storage projects on CAISO system peak. Comparing this metric across PAs (separately for PBI projects and non-PBI projects) reveals that projects administered by each PA discharged at a similar rate, on average, per kW rebated in 2015.

However, it is worth noting, particularly when our sample is broken out by program administrator, that the level of statistical confidence for these approximations is extremely poor. None of the averages in Table 6-6 achieves a precision[19] of 10% under a 90% confidence level, and most (21 of 27) fail to achieve even a 20% precision under an 80% confidence level. See Appendix E for further details.

Table 6-6: Estimate of Program-Wide Average Net Discharge (kW) During System Peak Hours (% of Rebated Capacity in parentheses), by Program Administrator, 2015[20]

kW	Top 1-50 Hours		Top 51-100 Hours		Top 101-150 Hours		Top 151-200 Hours	
	PBI	Non-PBI	PBI	Non-PBI	PBI	Non-PBI	PBI	Non-PBI
Total	235.3 (3%)	-17.6 (-1%)	191.3 (3%)	-9.2 (-1%)	188.0 (3%)	-7.6 (1%)	160.5 (2%)	-6.5 (-1%)
PG&E	204.8 (3%)	-6.6 (-1%)	183.6 (3%)	-8.1 (-1%)	177.8 (3%)	-7.0 (1%)	156.0 (22%)	-6.5 (-1%)
SCE	26.8 (4%)	-8.9 (-3%)	5.9 (1%)	-7.0 (-3%)	8.3 (1%)	-6.2 (2%)	3.1 (3%)	-4.0 (-2%)
SDG&E	N/A	-2.4 (-1%)	N/A	-1.7 (-1%)	N/A	-1.2 (0%)	N/A	-1.1 (0%)

We considered investigating the impacts on each PA's own coincident peak, but decided against doing so given the small sample sizes per PA and the resulting poor statistical confidence of the above analysis when disaggregated by PA.

Residential Projects

Due to the data limitations described in Section 6.2, we were not able to assess the coincident peak impacts of residential storage projects.

6.7 Looking Ahead

The coincident peak and carbon dioxide emissions impacts assessed in this report for non-residential projects flow from the storage discharging behavior observed in 2014 and 2015 and assessments of peak system demand hours and marginal emissions during this timeframe. This behavior and system conditions are by no means static. Policymakers could better incentivize customers and developers and enforce SGIP rules to reduce coincident peak impacts and reduce carbon dioxide emissions in the future.

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19 Precision is defined as the ratio of margin of error to sample average, presented in percentage terms.

20 The parenthesized percentage values in this table represent the average net discharge during system peak hours divided by the average rebated capacity in this subclass, over the same hour bucket.

Roundtrip Efficiency

Increasing battery RTE going forward could help reduce carbon dioxide emissions, especially if coupled with other dispatch incentives that aim to minimize carbon. All storage projects increase electricity usage on net, which, all else equal, tends to increase emissions. Higher RTE requirements and increased enforcement could reduce this effect. Table 7-15 displays the average RTE that would result in a zero emissions impact from the sampled non-residential storage projects: 80% - 89% for PBI projects (depending on the season) and 102% - 105% for non-PBI projects. This analysis is based on 2015 marginal emissions shape and charging patterns. An average RTE above these values should cause storage projects to reduce CO_2 emissions on net, assuming no other dispatch changes. Notably, this CO_2 'break-even' RTE for the non-PBI, non-residential projects is above 100%, so increasing RTE requirements and implementation will not, on its own, negate the negative emissions impacts of these projects.

Improving Timing of Storage Dispatch

While higher average RTE would still beneficially impact emissions under future marginal emissions shapes, charging timing may prove to be a larger driver of emission impacts in the future. California's marginal system cost and marginal emissions shapes will likely change considerably in future years. With SB 350 (De León) requiring 50% electric generation from renewable energy resources and the February 2016 CPUC decision to continue net energy metering, California is on track to increase its renewable generation substantially. Solar PV will likely comprise a large percentage of new renewable generation. As a result, marginal costs and emissions may be low or even zero in the middle of the day. Since renewables, hydropower, and natural gas will likely dominate the future California generation mix, marginal cost and emissions should be highly correlated. Storage projects could decrease net emissions and reduce peak demand to the extent that they can 1) charge during hours of over-generation or low marginal costs and emissions, and 2) discharge during high cost, high emission hours. Conversely, peak demand and net emissions may increase if charging occurs during time periods with higher marginal cost and emissions.

Given the increasing importance of favorable storage dispatch timing, temporal incentives including rate design will become increasingly critical. Rate design will remain a key incentive mechanism as long as storage project dispatch is compensated at retail rates. To minimize emissions from SGIP customers, rate designs should encourage charging during time periods with low marginal costs and emissions and encourage discharging during higher-cost, higher-emission hours.

Currently, the economic incentive for customers to dispatch storage for grid benefits or carbon dioxide emission mitigation is limited to the pricing signals provided by TOU rates and demand charges. On-Peak TOU periods are typically defined over 6-8 hours and do not provide incentives for shorter duration storage to target their discharge to the most valuable hours within that time period. The TOU definitions also do not vary beyond season and day type, while day-to-day variations in temperature and renewable generation cause substantial variation in hourly marginal cost and emission shapes. Therefore, time-of-use energy and demand charges provide only limited incentives for optimal storage dispatch. Similarly, monthly demand charges encourage customers to reduce their individual monthly peak loads, which are not necessarily coincident with high marginal emissions, utility system peak loads, or distribution level peak loads. Hence, current rate design leaves untapped much of the capability of energy storage to reduce emissions and provide system peak load reductions.

Some vendors such as Stem are participating in pilot programs such as PG&E's Supply-side Pilot (SSP) where they are reducing load to receive an award in the wholesale energy market. Stem is not, however, participating in PG&E's Excess Supply Pilot (XSP) to consume energy during periods of over-generation.[21]

Two key focus areas for achieving more optimal storage dispatch are 1) improving rate design incentives and 2) making sure the party responsible for dispatch receives the appropriate signals. Potential beneficial rate design adjustments include aligning time-of-use periods with marginal costs and emissions, applying on-peak demand charges, applying demand charges that vary geographically and reflect distribution peak hours, and instituting dynamic rates that offer more granular price signals and vary with system conditions. For example, the California Solar Initiative Research, Development and Demonstration (CSI RD&D) funded demonstration project "PV Integrated Storage: Demonstrating Mutually Beneficial Utility-Customer Business Partnerships" shows how customer-owned storage has significantly higher value when coordinated dispatch is enabled as compared to customer dispatch alone.[22]

Large Benefits under Well-Designed Policy

Together, stricter RTE requirements and enforcement, rate design improvements, and clear pathways to enabling third-party aggregators or utilities to assist in dispatching storage could enable storage to provide large reductions in system peak demand and carbon dioxide emissions under a high renewables future. Due to interdependencies, combining policies that target each of these key focus could produce even larger benefits.

6.8 Conclusions on Storage

We find the following conclusions.

On data:

- Poor data quality and limited data availability proved to be significant challenges for the analysis of AES. We are able to draw conclusions regarding the performance of AES for some metrics, but not for others.
- Increasing and enforcing data collection and quality requirements would substantially improve future SGIP storage program evaluation efforts.
- For 2015 we evaluated AES charge and discharge data for 21 of 29 PBI projects and 94 of 146 non-PBI, non-residential projects, though we do have less than a full year of data for most projects. We were able to match load data with AES data for only for 12 PBI projects in total. For residential projects, we have data for 36 projects from one provider, but poor data quality limited the analysis that could be performed.
- PBI projects had rebated capacities ranging from 100 kW to 2400 kW, and the non-PBI projects ranged between 9 kW and 29.99 kW.

21 Based on direct communication with PG&E.

22 Energy and Environmental Economics, "PV Integrated Storage: Demonstrating Mutually Beneficial Utility-Customer Business Partnerships", August 2016. Available online at: http://calsolarresearch.ca.gov/funded-projects/108-pv-integrated-storage-demonstrating-mutually-beneficial-utility-customer-business-partnerships

On storage project performance metrics:

- Only 58 of 115 (51%) non-residential projects operated with an AES capacity factor at 10% or above in 2015. Three PBI projects (14%) and 54 non-PBI, non-residential projects (57%) displayed an AES capacity factor of less than 10% (the assumed capacity factor for full payment of PBI projects) in 2015.
- The SGIP Greenhouse Gas Emission Standard requires a roundtrip efficiency of at least 63.5% on an annual basis. Only 25 of the 115 observed non-residential projects (22%) met this requirement during the 2014 – 2015 period. Over 95% of the PBI projects (20/21) but only 5% of the Non-PBI projects (5/94) met the efficiency requirement.
- Due to poor data quality, AES capacity factor and roundtrip efficiency could not be calculated for residential storage projects.

On storage dispatch behavior:

- TOU rate arbitrage did not appear to be a high priority for those dispatching non-residential storage projects in 2015. No PBI project discharged more than 75% of their total energy during on-peak TOU periods, and only 8 of the 17 PBI projects with summer dispatch discharged 50% or more of their energy on peak. One PBI project discharged virtually exclusively *off-peak*. On-peak discharge was even lower for non-PBI, non-residential projects. Only 5 of the non-PBI projects had 35% or more of their discharged energy on peak during 2015, and 18 projects (16%) discharged 70% or more of their energy *off-peak*.
- The average annual demand reduction across the five projects that had load and dispatch data available for a full summer was 0.8 kW in 2015. This metric ranged from a 37.3 kW *increase* in peak demand (a 1,000 kW project) to a 25.3 kW reduction in peak demand (for a 200 kW project). For this very small sample, demand charge reduction performance for AES is decidedly mixed.
- Due to poor data quality, we were not able to evaluate TOU rate arbitrage behavior with confidence for residential storage projects.
- On average, PBI projects tended to discharge in the late afternoon in the Summer and between 5 and 10 pm in the Winter. The non-PBI, non-residential projects exhibit no clear charge or discharge pattern.
- For the single provider of residential AES project data, storage appears to charge between 8 am and 1 pm, coincident with PV generation, and discharge during on-peak TOU periods.

On system coincident peak impacts:

- We estimate the *program-wide* contributions for the PBI projects to be 235, 191, 188 and 161 kW of discharge for the top 1-50, 51-100, 101-150 and 151-200 hours of 2015, respectively. Non-PBI, non-residential storage projects actually increased load on average during coincident peak load hours. For the non-PBI programs, we estimate program-wide impacts of 18, 9, 8 and 7 kW of net charging for the top 1-50, 51-100, 101-150 and 151-200 hours of 2015, respectively.
- Across there was relatively little variance across the different program administrators in terms of top hour demand contribution, there was a tendency for SCE projects to be slightly more demanding in peak system hours, per kW of de-rated capacity.
- Due to poor data quality, we were not able to evaluate coincident peak impacts for residential storage projects.

On CO_2 emissions:

- PBI projects charged during period of low marginal grid CO_2 emissions and discharged during period of higher marginal grid CO_2 emissions in 2015. Nevertheless, due to roundtrip efficiency losses, net CO_2 emissions increased by 13 metric tons for the 21 observed PBI projects taken together. The net CO_2 emissions from non-PBI projects are higher: a total increase of 19 tons from the 94 projects. We estimate the program-level impacts for the PBI and non-PBI projects to be 21 and 39 tons. respectively.
- There was little variance by program administrator across the non-PBI projects, on a per kW of de-rated capacity basis. For PBI projects, however, we saw that PG&E projects tended to contribute relatively more to emissions increases.
- For PBI projects, because the average emissions rate for discharging was higher than it was for discharging, we were able to conclude that a roundtrip efficiency of 80 - 89% (depending on the season) represents the theoretical breakeven point for emissions reduction, *assuming that storage projects exhibit 2015 charge and discharge behavior*. However, as the non-PBI projects actually discharged in lower emissions hours, on average, the theoretical breakeven point for emissions for non-PBI projects was 102 - 105%, meaning that an improvement in charging/discharging behavior, in addition to roundtrip efficiency, would be required for there to be an actual reduction in emissions.
- Due to poor data quality, we were not able to evaluate CO_2 emission impacts for residential storage projects.

Looking forward:

- Increases in roundtrip efficiency requirements and/or enforcement could allow storage projects to better reduce carbon dioxide emissions.
- In a high renewables future, storage projects could decrease net emissions and reduce peak demand to the extent that they can 1) charge during hours of over-generation or low marginal costs and emissions, and 2) discharge during high cost, high emission hours. Conversely, peak demand and net emissions may increase if charging occurs during time periods with higher marginal cost and emissions.
- Two key focus areas for achieving more optimal storage dispatch are:
  - 1-improving rate design incentives. To minimize emissions from SGIP customers, rate designs should encourage charging during time periods with low marginal costs and emissions and encourage discharging during higher-cost, higher-emission hours.
  - 2-shifting control of storage dispatch to entities that are better equipped to respond to those incentives.
- This evaluation did not consider the potential for storage to reduce emissions by providing renewables integration services. This could prove a useful addition to the evaluation in future years.

7 Environmental Impacts

7 ENVIRONMENTAL IMPACTS

The Self-Generation Incentive Program (SGIP) was originally established in 2001 to help address California's peak electricity supply shortcomings. Projects rebated by the SGIP were designed to maximize electricity generation during utility system peak periods and not necessarily to reduce greenhouse gas (GHG) or criteria pollutant emissions. Passage of Senate Bill (SB) 412 (Kehoe) required the California Public Utilities Commission (CPUC) to establish GHG goals for the SGIP.

This section discusses the GHG and criteria air pollutant impacts of the SGIP during calendar years 2014 and 2015. The fleet of projects whose impacts are evaluated in this section includes projects completed before the passage of SB 412. The GHG impact analysis is limited to carbon dioxide (CO_2) and CO_2 equivalent (CO_2eq) methane (CH_4) emissions impacts associated with SGIP projects. The criteria air pollutant impact analysis is limited to NO_X, PM_{10}, and SO_2 emissions impacts associated with SGIP projects. The discussion is organized into the following subsections:

- Methodology Overview and Summary of Environmental Impacts
- Non-renewable Project Impacts
- Renewable Biogas Project Impacts
- Wind and Pressure Reduction Turbine (PRT) Project Impacts
- Advanced Energy Storage (AES) Project Impacts
- Comparison to Build Margin Scenario

The scope of this analysis is further limited to operational impacts of SGIP projects and does not discuss any lifecycle emissions impacts that occur during the manufacturing, transportation, and construction of SGIP projects. A more detailed discussion of the environmental impacts methodology is included in Appendix C and Appendix D.

7.1 Background and Baseline Discussion

Emission impacts are calculated as the difference between the emissions generated by SGIP projects and baseline emissions that would have occurred in the absence of the program. The sources of these emissions (generated and avoided) vary by technology and fuel type. For example, all distributed generation technologies avoid emissions associated with displacing central station grid electricity, but only those that recover useful heat avoid emissions associated with displacing boiler use.

Grid Electricity Baseline

The passage of SB 412 established a maximum GHG emissions rate for SGIP technologies. Beginning in 2011, eligibility for SGIP projects was limited to projects that did not exceed an emissions rate of 379 kg CO_2/MWh over ten years. Most recently, the CPUC revised the maximum GHG emission rate for eligibility to 350 kg CO_2/MWh over ten years for projects applying to the SGIP in 2016.

When developing these emission factors for eligibility, the CPUC must look forward and forecast what baseline grid conditions will look like during an SGIP project's life. These forecasts must make assumptions about power plant efficiencies and the useful life of SGIP projects. By contrast, an impact evaluation has the benefit of being backwards looking and is able to leverage historical data to quantify the grid electricity baseline. Consequently, the avoided grid emissions rates used in this impact evaluation report to assess project performance are different than the avoided grid emissions factors used to screen SGIP applications for program eligibility requirements.

This study relies on an "operating margin" approach to quantify the grid electricity baseline for impact evaluation purposes. At the request of the CPUC, this study will also investigate the performance of the program assuming a "build margin" baseline is applied. The details of these two approaches, including a discussion of the methodologies and the sources of data, are described in Appendix C. Table 7-1 summarizes the weighted average emissions rates that apply to SGIP projects under both baselines based on the approaches summarized in Appendix C. Program impacts are always assessed using the operating margin baseline. Build margin factors are included for comparison purposes.

Table 7-1: Summary of Electric Baselines

Calendar Year	Operating Margin (Wt. Avg. kg CO_2 / MWh)	Build Margin (Wt. Avg. kg CO_2 / MWh)
2014	422	377
2015	420	376

Greenhouse Gas Impact Summary

The GHG impacts for each Program Administrator (PA) are shown in Table 7-2 for 2014 and 2015.

Table 7-2: Greenhouse Gas Impacts by Program Administrator and Calendar Year[1]

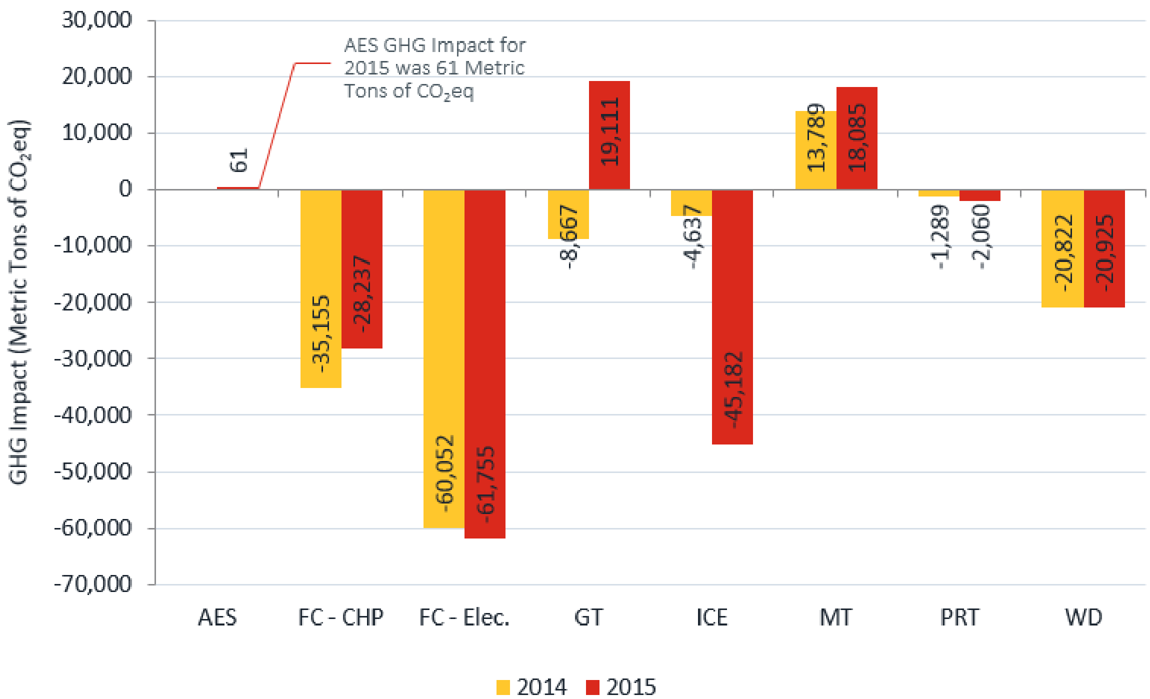
Program Administrator	Calendar Year	Greenhouse Gas Impact (Metric Tons CO_2eq)	Total Rebated Capacity (MW)	Greenhouse Gas Metric Tons CO_2eq per Rebated MW	Percent of Greenhouse Gas Impact
CSE	2014	-18,831	37.2	-507	16.1%
PG&E		-42,483	133.9	-317	36.4%
SCE		-40,284	77.2	-522	34.5%
SCG		-15,237	102.1	-149	13.0%
Total		***-116,835***	***350.3***	***-334***	***100%***
CSE	2015	-8,866	44.8	-198	7.3%
PG&E		-67,277	188.9	-356	55.6%
SCE		-38,176	99.0	-386	31.6%
SCG		-6,583	107.4	-61	5.4%
Total		***-120,903***	***440.2***	***-275***	***100%***

Figure 7-1 shows the GHG impacts of the eight major technology types rebated by the SGIP. The impacts reported in Figure 7-1 represent program level impacts for all fuel types (renewable and non-renewable).

1 Environmental impacts for AES projects in 2014 were not calculated; therefore, the rebated capacities reported for 2014 exclude AES projects.

However, the environmental impacts for renewable and non-renewable projects vary greatly for any given technology. Detailed breakdowns of environmental impacts by technology and fuel type are provided in subsequent figures and tables.

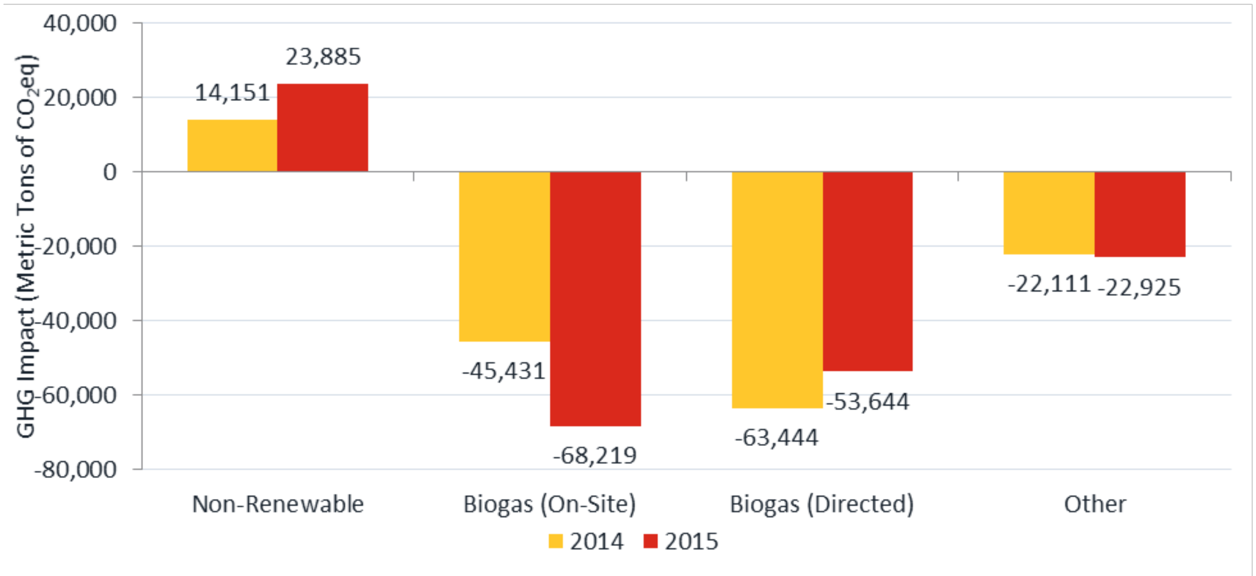
Figure 7-1: Greenhouse Gas Impacts by Technology Type and Calendar Year



Electric only fuel cells achieved the largest reductions in GHG emissions during 2014 and 2015, followed by internal combustion engines in 2015. Microturbines were the only technology type that increased greenhouse gas emissions during 2014 and 2015 relative to a conventional energy services baseline. Emissions from gas turbines turned positive during 2015, whereas emissions from internal combustion engines significantly decreased in 2015. Advanced energy storage projects increased emissions slightly during 2015.

GHG impacts in Figure 7-1 include both non-renewable and renewable projects. Figure 7-2 summarizes GHG impacts by energy source.

Figure 7-2: Greenhouse Gas Impacts by Energy Source and Calendar Year



On average, non-renewable projects increased GHG emissions during 2014 and 2015. Projects fueled by all other energy sources achieved GHG emissions reductions. The majority of SGIP emissions reductions arise from on-site and directed biogas projects. The energy source 'Other' includes storage, wind turbines, and pressure reduction turbines.

Criteria Air Pollutant Impact Summary

This 2014-2015 impact evaluation assesses the criteria pollutant emissions impacts due to SGIP projects operating as of December 31, 2015. In estimating criteria air pollution impacts, assumptions have been made regarding representative efficiencies and emission rates of combined cycle gas turbine (CCGT) and combustion turbines (CT) used to provide grid power as well as representative emission rates for DG technologies deployed under the SGIP. Appendix D contains the methodology, assumptions, and references used in estimating 2014-15 impacts from criteria air pollutant emissions.

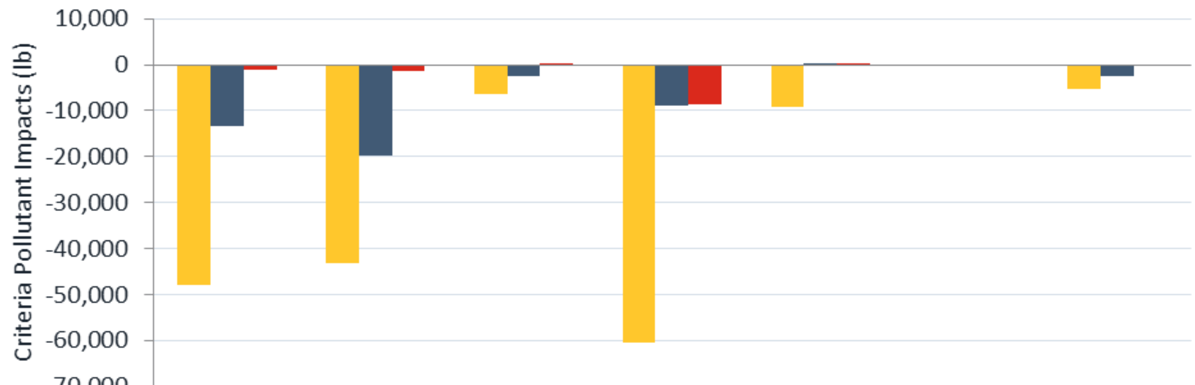
During 2014 and 2015 combined, SGIP projects decreased NO_X and PM_{10} emissions by 370,003 pounds and 97,341 pounds respectively. During the same period SO_2 emissions decreased by 18,508 pounds relative to the absence of the program. The criteria pollutant impacts attributed to each PA are shown in Table 7-3.

Table 7-3: Criteria Pollutant Impacts by Program Administrator (2014 and 2015 Combined)

Program Administrator	NO_X Impact (lb)	PM_{10} Impact (lb)	SO_2 Impact (lb)	Total Rebated Capacity (MW)
CSE	-13,914	-10,116	-1,721	44.3
PG&E	-171,697	-39,016	-4,764	174.8
SCE	-92,171	-25,811	-7,226	93.0
SCG	-92,221	-22,399	-4,797	106.8
Total	***-370,003***	***-97,341***	***-18,508***	***418.9***

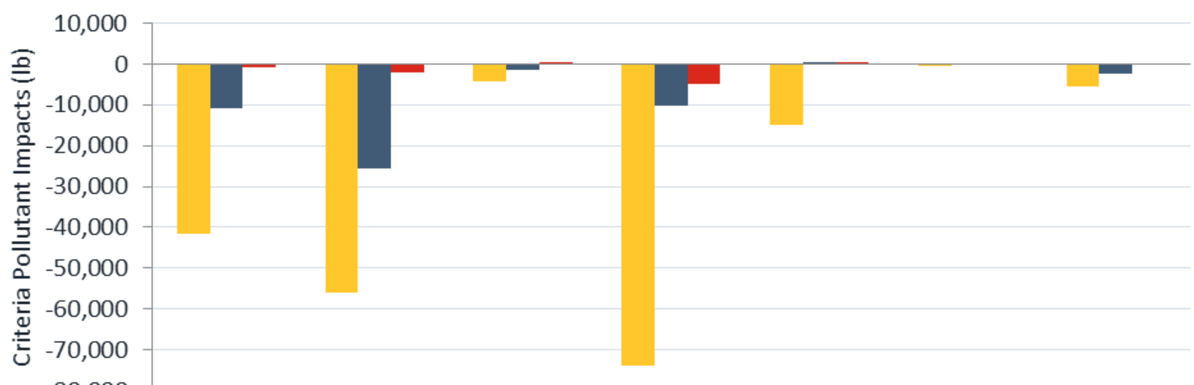
Figure 7-3 and Figure 7-4 show the criteria pollutant impacts by technology type during 2014 and 2015 respectively.

Figure 7-3: Criteria Pollutant Impacts by Technology Type (2014)



	FC - CHP	FC - Elec.	GT	ICE	MT	PRT	WD
NOx	(48,058)	(43,238)	(6,337)	(60,531)	(9,056)	(345)	(5,416)
PM10	(13,321)	(19,697)	(2,494)	(8,791)	14	(155)	(2,421)
SO2	(1,054)	(1,527)	124	(8,599)	153	(12)	(194)

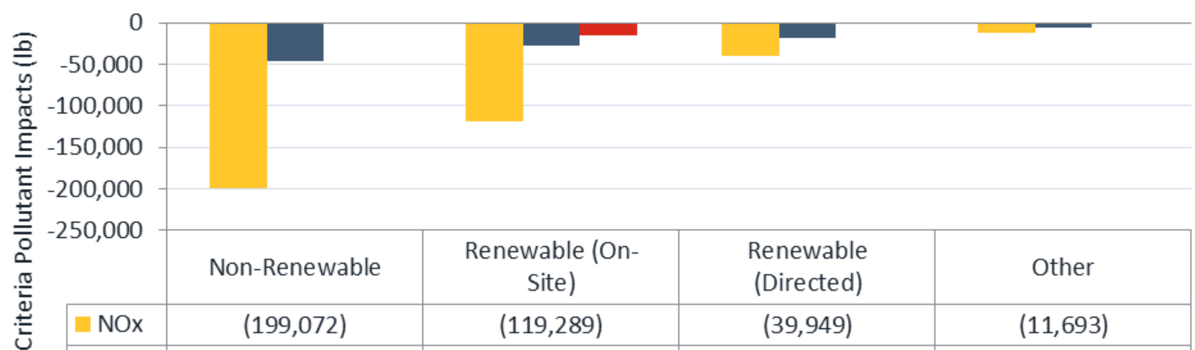
Figure 7-4: Criteria Pollutant Impacts by Technology Type (2015)



	FC - CHP	FC - Elec.	GT	ICE	MT	PRT	WD
NOx	(41,623)	(56,120)	(4,382)	(74,012)	(14,954)	(546)	(5,386)
PM10	(10,832)	(25,552)	(1,492)	(10,109)	157	(245)	(2,404)
SO2	(827)	(1,992)	196	(4,762)	200	(19)	(195)

All SGIP technologies achieved NO_X emissions reductions but the largest contributions came from fuel cells and internal combustion engines. The large pollutant reductions from these projects relative to non-fueled technologies are due to small number of non-fueled projects in the SGIP. SO_2 emissions impacts were minor except for internal combustion engines, which contributed to the largest decreases in SO_2 emissions. Additional information on criteria pollutant impacts by technology type and energy source are provided in subsequent sections. Figure 7-5 summarizes criteria pollutant impacts by energy source.

Figure 7-5: Criteria Pollutant Impacts by Energy Source (2014 and 2015)



	Non-Renewable	Renewable (On-Site)	Renewable (Directed)	Other
NOx	(199,072)	(119,289)	(39,949)	(11,693)
PM10	(45,728)	(27,898)	(18,491)	(5,225)
SO2	(1,234)	(15,418)	(1,436)	(420)

All energy sources decreased NO_X, PM_{10}, and SO_2 emissions. The following subsections describe in more detail the environmental impacts of SGIP projects by energy source.

7.2 Non-renewable Project Impacts

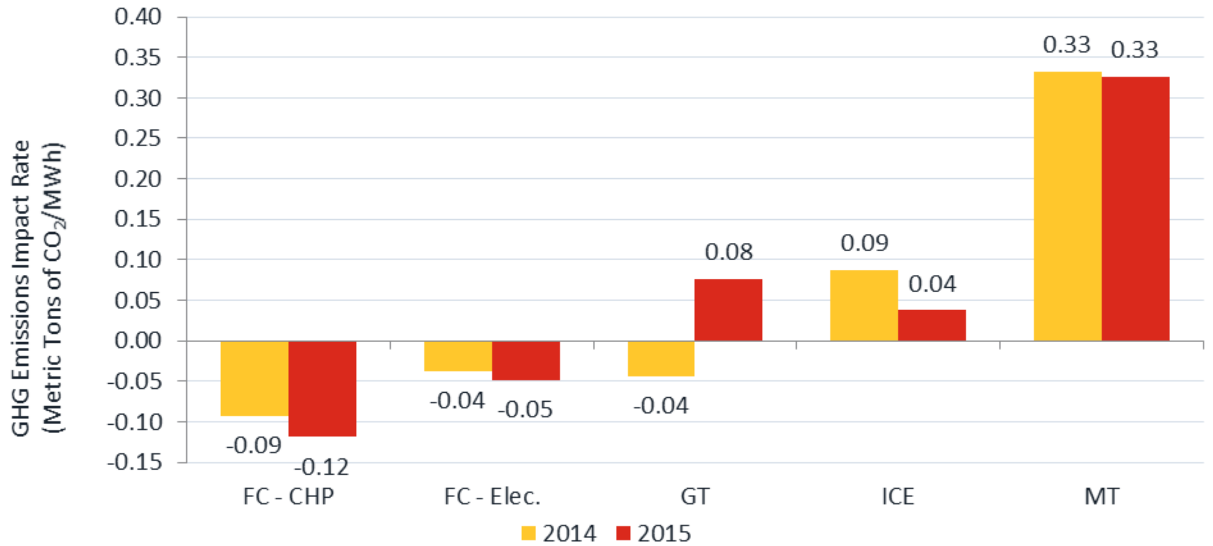
Non-renewable SGIP projects include CHP fuel cells, electric-only fuel cells, gas turbines, internal combustion engines, and microturbines. These projects consume natural gas and generate electricity to serve a customer's load. Non-renewable SGIP projects produce emissions that are proportional to the amount of fuel they consume. In the absence of the program, the customer's electrical load would have been served by the electricity distribution company. Consequently, if SGIP projects only served electrical loads, they would need to generate electricity more cleanly than the avoided marginal grid generator to achieve GHG emission reductions.

SGIP CHP projects are able to recover waste heat and use it to serve on-site thermal loads. The recovered waste heat may be used to serve a customer's heating or cooling needs. In the absence of the SGIP, a heating end use is assumed to be met by a natural gas boiler, and a cooling end use is assumed to be met by an electric chiller. Natural gas boilers generate emissions associated with the combustion of the gas to heat water. The emissions associated with electric chillers are due to the central station plant that would have generated the electricity to run the chiller. Emissions impacts are the difference between SGIP emissions and avoided emissions.

Non-renewable Project Greenhouse Gas Impacts

The GHG performance of non-renewable SGIP projects is summarized in Figure 7-6.

Figure 7-6: Greenhouse Gas Impact Rate by Technology Type and Calendar Year (Non-renewable Fuel)



Non-renewable CHP fuel cells and electric-only fuel cells decreased GHG emissions in 2014 and 2015. Gas turbines decreased emissions in 2014 but saw increased emissions in 2015. Non-renewable internal combustion engines and microturbines increased emissions during 2014 and 2015. It should be noted that Figure 7-6 shows GHG emissions impact rates in metric tons of CO_2 per MWh. To arrive at 2014 or 2015 GHG impacts these rates must be multiplied by the non-renewable electrical generation impact. This is important because while non-renewable microturbines had the largest emissions impact rate during 2014 (0.33 metric tons of CO_2 per MWh), they had the lowest electrical generation impact among non-renewable technologies (48,990 MWh during 2014).

GHG impacts are the net difference between SGIP emissions and total avoided emissions. The individual components contributing to non-renewable emissions impacts for each technology type are listed in Table 7-4 and Table 7-5.

Table 7-4: Non-renewable Greenhouse Gas Impacts by Technology Type (2014)

	Metric Tons of CO_2 per MWh						
Technology Type	SGIP Emissions (A)	Electric Power Plant Emissions (B)	Heating Services (C)	Cooling Services (D)	Total Avoided Emissions (E=B+C+D)	Emissions Impact (F=A-E)	Annual Energy Impact (MWh)
FC – CHP	0.48	0.42	0.15	0.01	0.58	-0.09	60,864
FC – Elec.	0.38	0.42	0.00	0.00	0.42	-0.04	243,057
GT	0.52	0.43	0.11	0.02	0.56	-0.04	199,121
ICE	0.66	0.42	0.13	0.01	0.57	0.09	243,232
MT	0.86	0.42	0.10	0.01	0.53	0.33	48,990

CHP fuel cells and gas turbines have a higher emissions rate than the electrical power plants that they avoid (A > B) but are able to overcome this deficit by recovering useful heat for heating (C) and cooling (D) services. The result is a negative emission impact (F) relative to the conventional energy services baseline. Electric-only fuel cells do not recover useful heat but have a lower emissions rate than the electric power plants they avoid (A < B). Internal combustion engines and microturbines had high emissions rates and did not recover sufficient useful heat to achieve negative GHG impacts.

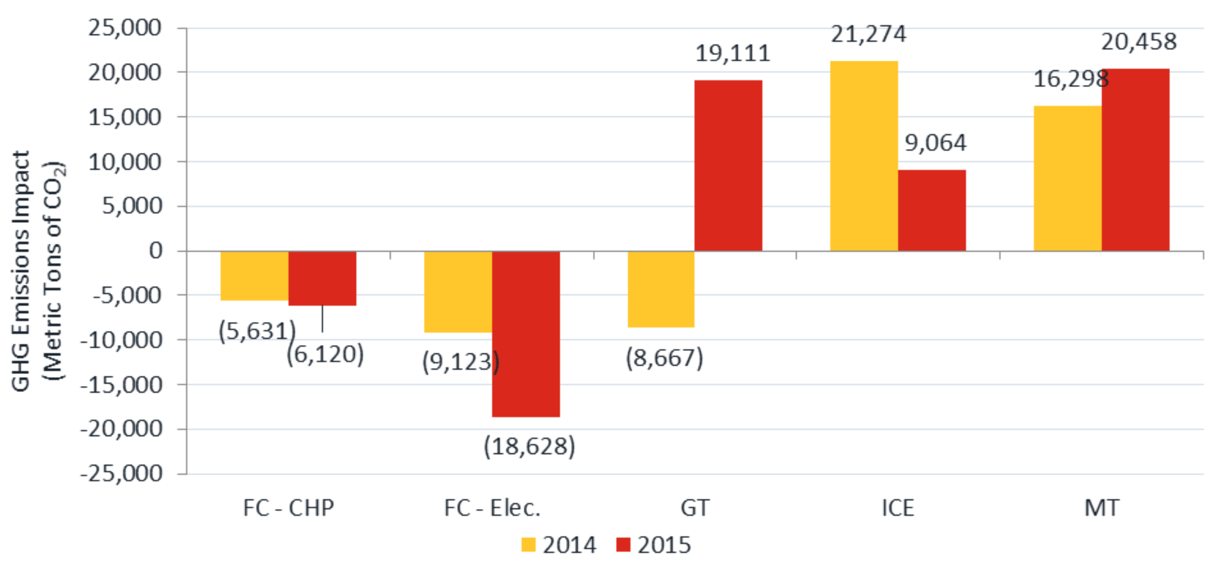
When reviewing SGIP GHG impacts results, it is important to keep in mind that results for technologies are reported in aggregate and are not necessarily indicative of individual project performance or technology potential. Non-renewable internal combustion engines and microturbines are capable of achieving GHG emissions reductions, and some do. However, when viewed as a group, their combined performance resulted in increased GHG emissions.

Table 7-5: Non-renewable Greenhouse Gas Impacts by Technology Type (2015)

Technology Type	Metric Tons of CO_2 per MWh						Annual Energy Impact (MWh)
	SGIP Emissions (A)	Electric Power Plant Emissions (B)	Heating Services (C)	Cooling Services (D)	Total Avoided Emissions (E=B+C+D)	Emissions Impact (F=A-E)	
FC – CHP	0.51	0.42	0.19	0.01	0.62	-0.12	51,637
FC – Elec.	0.37	0.42	0.00	0.00	0.42	-0.05	385,925
GT	0.59	0.42	0.08	0.02	0.51	0.08	251,859
ICE	0.61	0.42	0.13	0.02	0.57	0.04	240,619
MT	0.88	0.42	0.13	0.01	0.55	0.33	62,805

Results for 2015 are similar to 2014 with the exception of gas turbines. The SGIP emissions (A) associated with gas turbines in 2015 were much greater than in 2014. This resulted in a positive emission impact (F) despite avoided electric, heating, and cooling services emissions. The total CO_2 impact of non-renewable projects is shown in Figure 7-7.

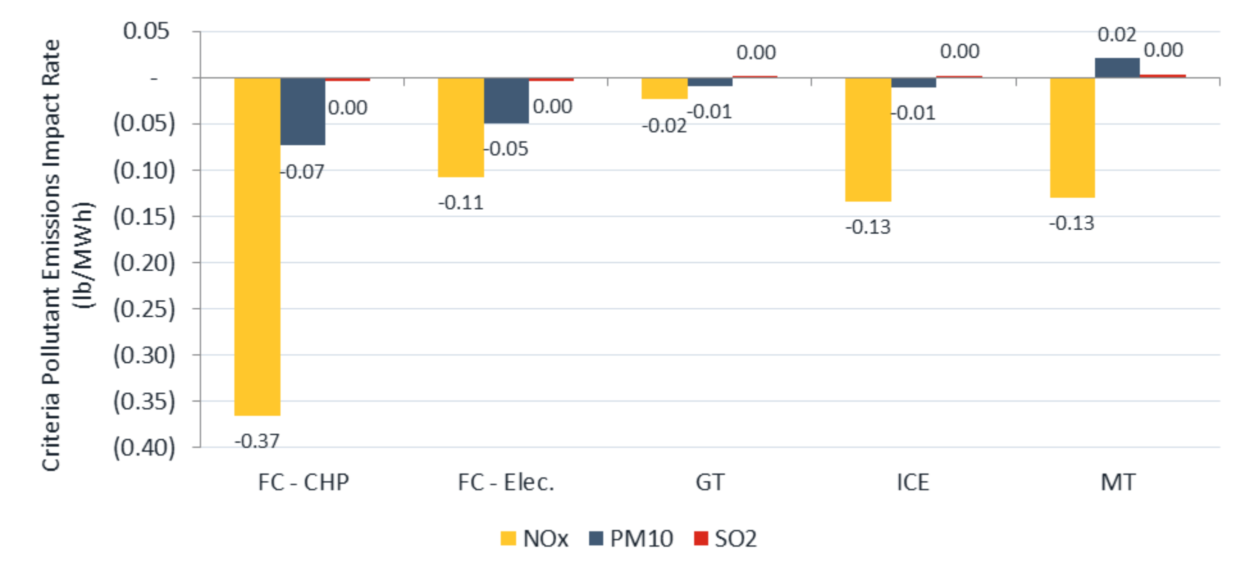
Figure 7-7: Non-renewable Greenhouse Gas Impact by Technology Type (2014 and 2015)



Non-renewable Project Criteria Pollutant Impacts

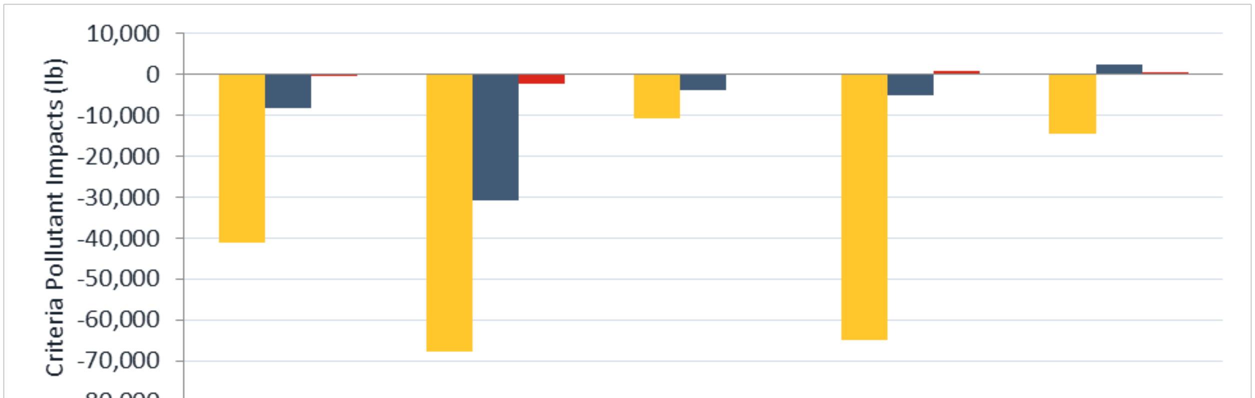
Like GHG emissions, the net impact of criteria air pollutant emissions is proportional to the amount of fuel consumed by the SGIP technology to generate electricity relative to grid sources and the amount of avoided boiler fuel. The criteria pollutant emission performance of non-renewable SGIP projects is summarized in Figure 7-8 for 2014 and 2015.

Figure 7-8: Criteria Pollutant Impact Rate by Technology Type (Non-renewable Fuel, 2014 and 2015)



All technologies supplied with non-renewable fuel decreased NO_X and PM_{10} emissions. SO_2 emissions from technologies supplies with non-renewable fuel were marginal. These results indicate that non-renewable SGIP technologies with high electrical efficiencies and low air pollutant emissions (e.g., fuel cells) generate fewer emissions than the conventional energy services baseline. In addition, SGIP technologies with lower electrical efficiencies but which recovered useful waste heat reduce criteria air pollutants overall. The total criteria pollutant impact for non-renewable projects is shown in Figure 7-9.

Figure 7-9: Criteria Pollutant Impact by Technology Type (Non-renewable Fuel, 2014 and 2015)



	FC - CHP	FC - Elec.	GT	ICE	MT
NOx	(41,156)	(67,701)	(10,719)	(64,959)	(14,538)
PM10	(8,258)	(30,835)	(3,986)	(4,938)	2,289
SO2	(474)	(2,395)	320	908	407

7.3 Renewable Biogas Project Impacts

SGIP renewable biogas projects include CHP fuel cells, electric-only fuel cells, microturbines, and internal combustion engines. Almost 20 percent of the total SGIP rebated capacity is fueled by renewable biogas. Sources of biogas include landfills, wastewater treatment plants (WWTP), dairies, and food processing facilities. Analysis of the emission impacts associated with renewable biogas SGIP projects is more complex than for non-renewable projects. This complexity is due in part to the additional baseline component associated with biogas collection and treatment in the absence of the SGIP project installation. In addition, some projects generate only electricity while others are CHP projects that use waste heat to meet site heating and cooling loads. Consequently, renewable biogas projects can directly impact emissions the same way that non-renewable projects can, but they also include emission impacts caused by the treatment of the biogas in the absence of the program.

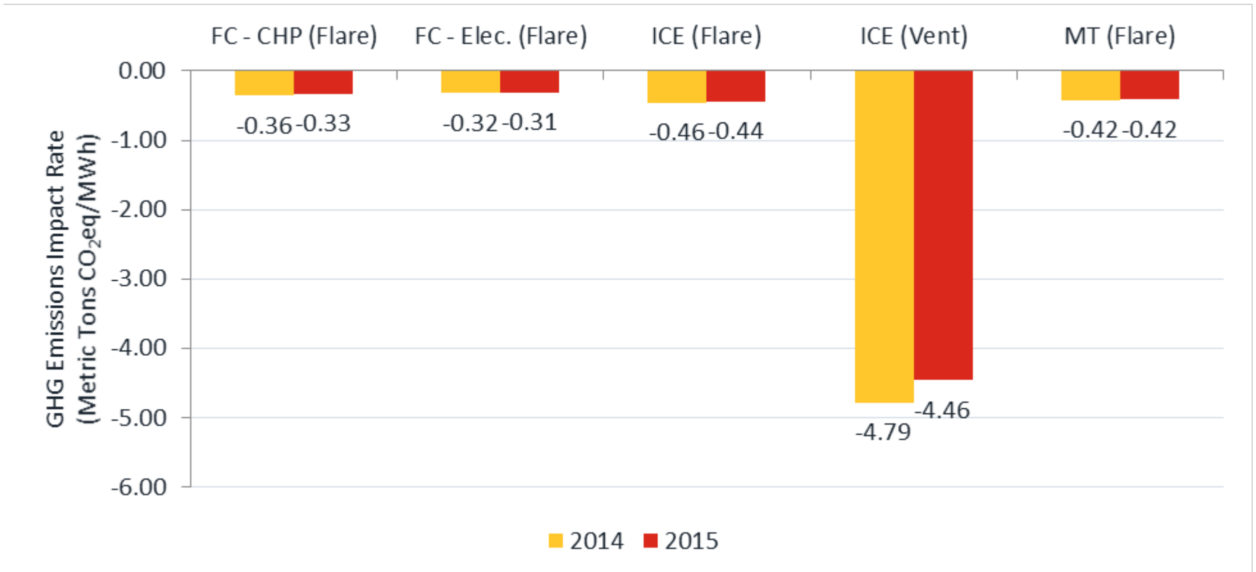
Renewable biogas SGIP projects capture and use biogas that otherwise may have been emitted into the atmosphere (vented) or captured and burned (flared). By capturing and utilizing this gas, emissions from venting or flaring the gas are avoided. The concept of avoided biogas emissions is further explained in Appendix C.

Renewable Biogas Project Greenhouse Gas Impacts

When reporting emissions impacts from different types of greenhouse gases, total GHG emissions are reported in terms of metric tons of CO_2 equivalent so that direct comparisons can be made across technologies and energy sources. On a per mass unit basis, the global warming potential of CH_4 is 21 times that of CO_2. The biogas baseline estimates of vented emissions (CH_4 emissions from renewable SGIP facilities) are converted to CO_2eq by multiplying the metric tons of CH_4 by 21. In this section, CO_2eq emissions are reported if projects with a biogas venting baseline are included, otherwise; CO_2 emissions are reported.

The GHG performance of renewable biogas SGIP projects is summarized in Figure 7-10 by technology type and biogas baseline for 2014 and 2015. CHP fuel cells, electric-only fuel cells, internal combustion engines, and microturbines were deployed in locations that would otherwise have flared biogas. Internal combustion engines were the only technology deployed at locations such as dairies that would otherwise have vented biogas.

Figure 7-10: Renewable Biogas Greenhouse Gas Impact Rates by Technology and Biogas Baseline Type (2014 and 2015)



All renewable biogas technologies reduced GHG emissions regardless of the biogas baseline. Technologies with flaring biogas baselines achieved reductions between 0.31 and 0.46 metric tons of CO_2 per MWh. Internal combustion engines with venting biogas baselines achieved GHG reductions that were an order of magnitude greater at 4.46 to 4.79 metric tons of CO_2eq per MWh. The individual components contributing to renewable emissions impacts for each technology and biogas baseline are listed in Table 7-6 and Table 7-7.

Table 7-6: Renewable Biogas Greenhouse Gas Impacts by Technology and Biogas Baseline Type (2014)

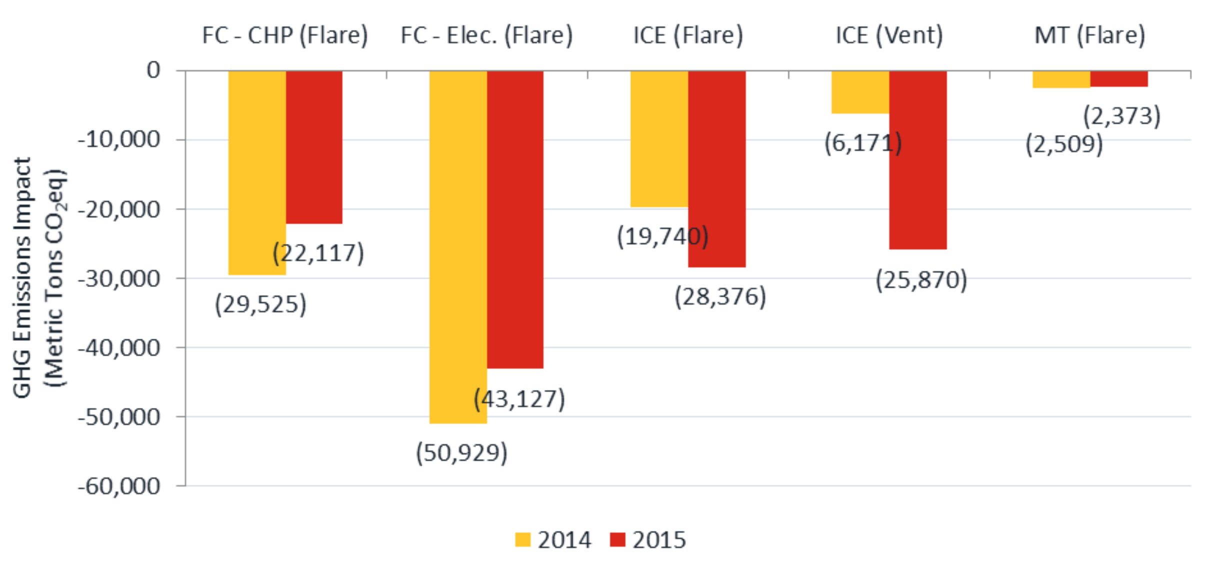
Technology Type	Metric Tons of CO_2 per MWh						Annual Energy Impact (MWh)
	SGIP Emissions (A)	Electric Power Plant Emissions (B)	Heating Services (C)	Biogas Treatment (D)	Total Avoided Emissions (E=B+C+D)	Emissions Impact (F=A-E)	
FC – CHP (Flare)	0.48	0.42	0.00	0.42	0.85	-0.36	81,790
FC – Elec. (Flare)	0.38	0.42	0.00	0.29	0.71	-0.32	157,369
ICE (Flare)	0.66	0.42	0.04	0.66	1.11	-0.46	43,121
ICE (Vent)	0.66	0.42	0.00	5.03	5.45	-4.79	1,289
MT (Flare)	0.86	0.42	0.00	0.86	1.28	-0.42	5,975

Table 7-7: Renewable Biogas Greenhouse Gas Impacts by Technology and Biogas Baseline Type (2015)

Technology Type	Metric Tons of CO_2 per MWh						Annual Energy Impact (MWh)
	SGIP Emissions (A)	Electric Power Plant Emissions (B)	Heating Services (C)	Biogas Treatment (D)	Total Avoided Emissions (E=B+C+D)	Emissions Impact (F=A-E)	
FC – CHP (Flare)	0.51	0.42	0.00	0.41	0.83	-0.33	67,350
FC – Elec. (Flare)	0.37	0.42	0.00	0.26	0.68	-0.31	138,569
ICE (Flare)	0.61	0.42	0.02	0.61	1.05	-0.44	63,997
ICE (Vent)	0.61	0.41	0.00	4.66	5.07	-4.46	5,799
MT (Flare)	0.88	0.42	0.00	0.88	1.29	-0.42	5,698

The total CO_2eq impact of renewable biogas projects is shown in Figure 7-11.

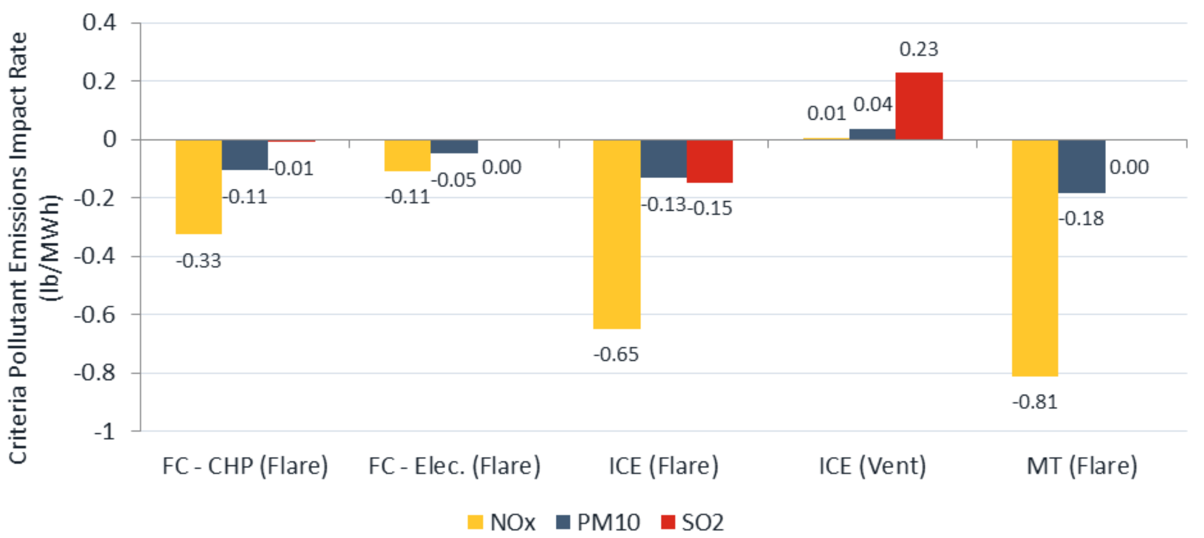
Figure 7-11: Renewable Biogas Greenhouse Gas Impact by Technology and Biogas Baseline Type (2014 and 2015)



Renewable Biogas Project Criteria Pollutant Impacts

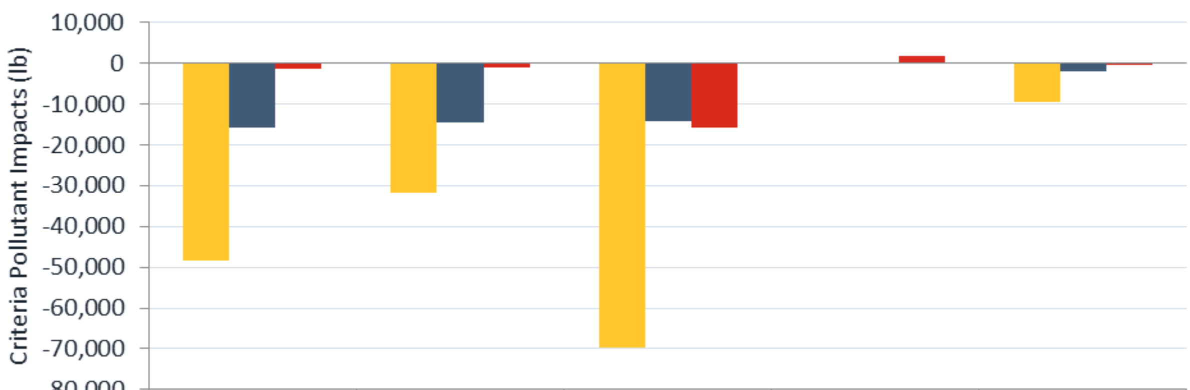
The criteria pollutant emission performance of renewable biogas SGIP projects is summarized in Figure 7-12. All technologies with flaring biogas baseline reduce criteria pollutant impacts due to avoided emissions from the flare and from the grid baseline. Internal combustion engines with venting baselines do not reduce criteria pollutants since the methane is only converted into criteria pollutants after the combustion process. In the baseline, the vented biogas remains as methane.

Figure 7-12: Criteria Pollutant Impact Rates by Technology Type and Biogas Baseline (2014 and 2015 Combined)



The total criteria pollutant impact for renewable biogas projects is shown in Figure 7-13.

Figure 7-13: Criteria Pollutant Impact by Technology Type and Biogas Baseline (2014 and 2015 Combined)



	FC - CHP (Flare)	FC - Elec. (Flare)	ICE (Flare)	ICE (Vent)	MT (Flare)
NOx	(48,525)	(31,657)	(69,633)	49	(9,472)
PM10	(15,894)	(14,413)	(14,220)	258	(2,119)
SO2	(1,407)	(1,124)	(15,892)	1,623	(53)

7.4 Wind and Pressure Reduction Turbine Project Impacts

Wind turbine and pressure reduction turbine (PRT) projects do not consume any type of fuel and do not recover waste heat. Their emissions reduction rates (both CO_2 and criteria pollutants) are equal to the emissions rate of the grid as described in Appendix C and Appendix D. The individual components contributing to wind and PRT greenhouse gas emissions impacts are listed in Table 7-8 and Table 7-9.

Table 7-8: Wind and Pressure Reduction Turbine Greenhouse Gas Impacts (2014)

Technology Type	Metric Tons of CO_2 per MWh				Annual Energy Impact (MWh)
	SGIP Emissions (A)	Electric Power Plant Emissions (B)	Total Avoided Emissions (C=B)	Emissions Impact (D=A-C)	
PRT	0.00	0.43	0.43	-0.43	3,016
WD	0.00	0.42	0.42	-0.42	49,867

Table 7-9: Wind and Pressure Reduction Turbine Greenhouse Gas Impacts (2015)

Technology Type	Metric Tons of CO_2 per MWh				Annual Energy Impact (MWh)
	SGIP Emissions (A)	Electric Power Plant Emissions (B)	Total Avoided Emissions (C=B)	Emissions Impact (D=A-C)	
PRT	0.00	0.42	0.42	-0.42	4,865
WD	0.00	0.41	0.41	-0.41	50,509

7.5 Build Margin Comparison

In D. 15-11-026 (November 19, 2015), the CPUC revised the GHG emission factor to determine eligibility to participate in the SGIP pursuant to Public Utilities Code Section 379.6(b)(2) as amended by SB 861. Subsequently, the CPUC directed Itron to incorporate the methodology discussion in this Decision into the 2014-2015 SGIP Impact Evaluation Report. This section compares the greenhouse gas impacts discussed previously to the “build margin” scenario proposed by the CPUC.

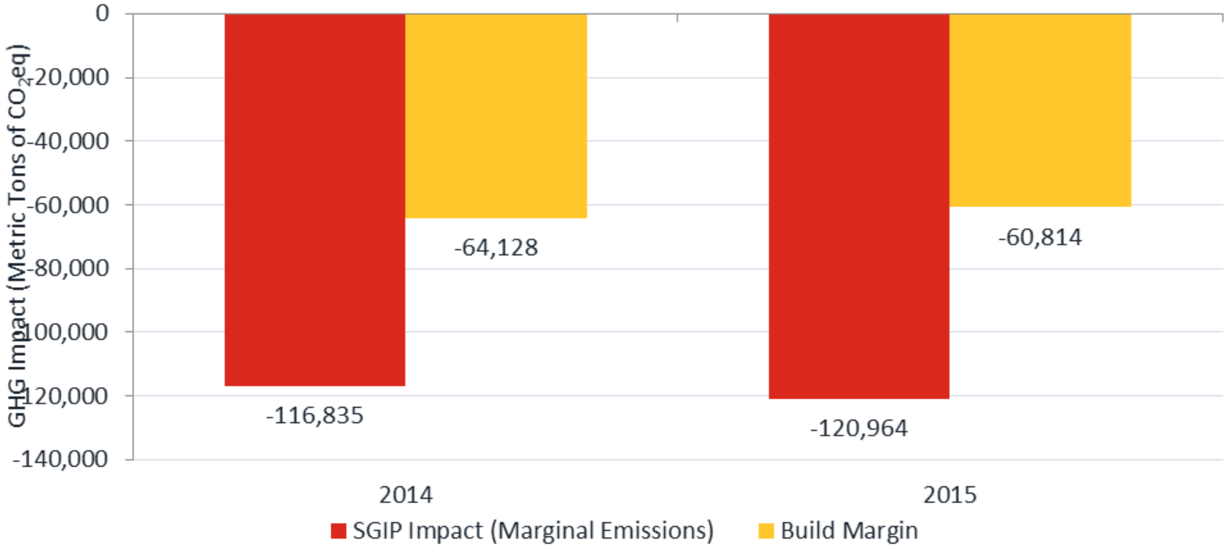
This Impact Evaluation report has adopted a methodology originally developed by Energy and Environmental Economics (E3) for treating GHG emissions avoided by energy efficiency measures. Similar to the logic employed by E3 for energy efficiency measures, we assume that SGIP technologies influence the marginal emissions from the electricity generation system. We assume that electricity generated by SGIP technologies installed on-site avoids the generation of electricity from the last generator to clear the CAISO market. In D. 15-11-026, this effect is called the “operating margin” effect.

D. 15-11-026 agrees that SGIP technologies influence the operating margin but goes on to pose that SGIP technologies also influence the construction of future grid-scale generation technologies. D. 15-11-026 calls this effect the “build margin” effect.

The following section compares the GHG impacts discussed in previous sections to the “build margin” scenario posed by the CPUC. A detailed discussion of both the GHG impact approach and the build margin scenario methodology is found in Appendix C.

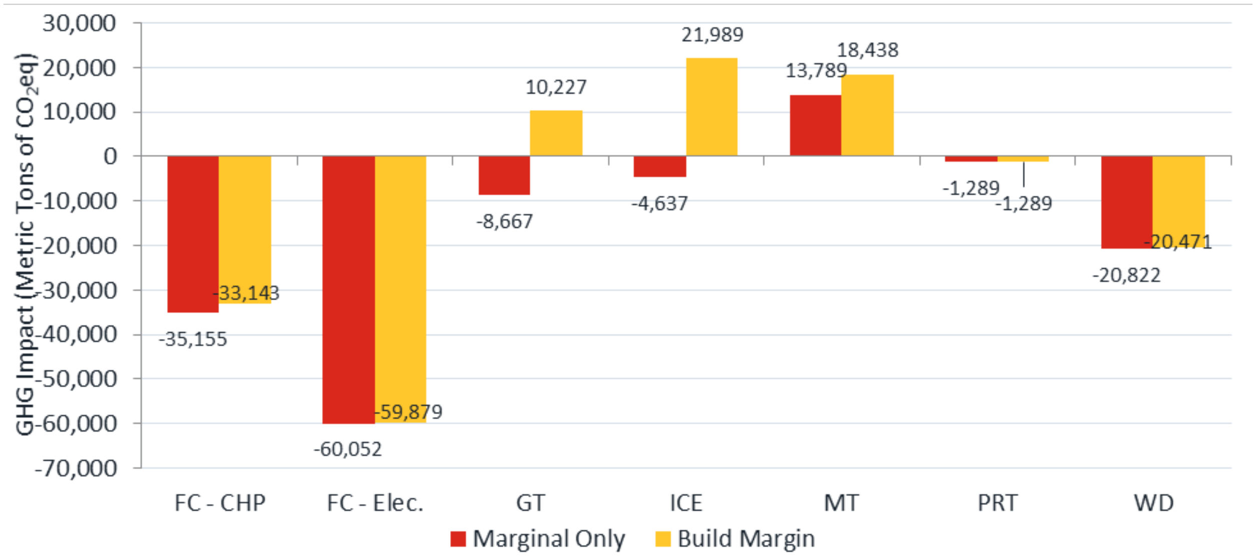
Figure 7-14 compares the total SGIP GHG impact to the build margin scenario.

Figure 7-14: Comparison of SGIP Emission Impact to Build Margin Scenario



The build margin approach assumes that renewable capacity is displaced after a project's fifth year of operation. Consequently, the avoided emissions rate becomes lower for older projects which leads to a reduction in the GHG impact (less benefit). Figure 7-15 compares the 2014 GHG impact to the build margin scenario by technology.

Figure 7-15: Comparison of 2014 GHG Impact to Build Margin Scenario by Technology



Since the build margin effect manifests itself after the fifth year of operation, the impact is more pronounced for technologies that have been in the SGIP for longer periods of time. Gas turbines, internal combustion engines, and microturbines are most affected as they are among the oldest technologies in the program. Fuel cells (CHP and electric-only) and wind turbines have only a modest impact as they are relatively newer technologies. Pressure reduction turbines have no impact since all PRT projects are less than five years old.

7.6 Advanced Energy Storage Project Impacts

The impact of SGIP storage projects on CO_2 emissions depends on two opposing components: 1) the degree to which storage projects are used to move load from higher marginal emissions hours to lower marginal emissions hours, and 2) how much additional electricity is demanded when batteries are added to the grid to compensate for their less-than-perfect roundtrip efficiency. The emissions calculations in this subsection follow the same methodology used for non-AES projects and is described in more detail in Appendix C.

It is important to note that the 2014 – 2015 impacts described here are those that accompany 2015 discharge behavior, and that further incentivizing storage projects to optimize their charging behavior to minimize carbon dioxide emissions could produce different results in the future. Additional thoughts on policy interventions that could achieve this aim were discussed in Section 6. Further, this report does not attempt to quantify any CO_2 benefits flowing from the role of storage projects in grid integration of renewable energy generation resources. This could be an interesting area of analysis in future impact evaluation reports as California continues on the path to a high-renewables future.

Non-residential Projects

2014

The charging behavior shown in Section 6, charging in the evening and overnight, discharging in the middle of the day, combined with an increase in electricity demand as a result of losses, causes an overall increase in emissions of 5.6 metric tons of CO_2 for the two (PBI) projects operating in 2014.

The available sample of two 2014 projects was insufficiently robust to scale these results to population impacts.

2015

To determine the extent to which storage projects operating in 2015 moved load from higher to lower marginal emissions hours, we compared the aggregate net discharge for each hour in the day to the marginal emissions rate in that same hour. See Figure 7-16 and Figure 7-17, which show the correlation between these two variables for PBI and non-PBI non-residential projects, respectively. Note that net **discharging is shown as positive values in green** and **charging as negative values in red**.

Figure 7-16: Marginal Emissions Compared to Aggregate Discharge (Charge), PBI Projects, 2015

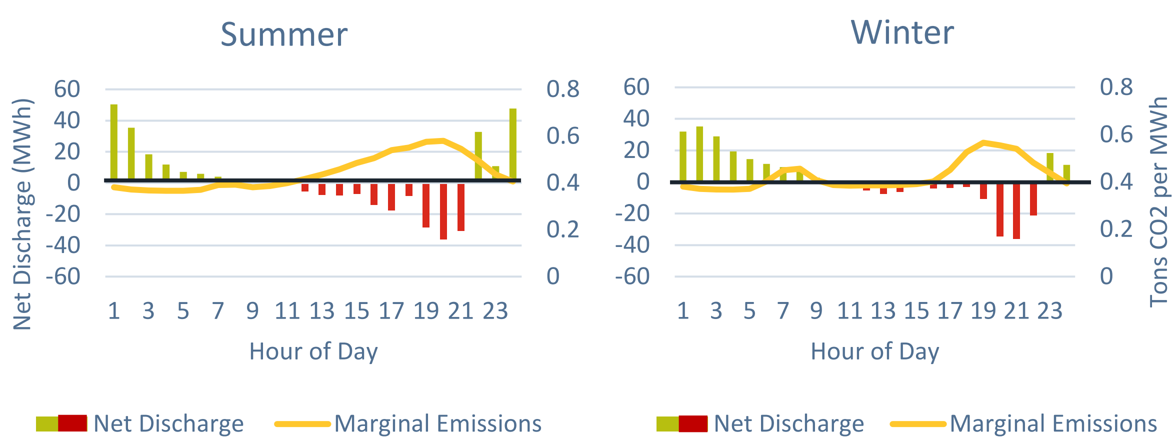


Figure 7-17: Marginal Emissions Compared to Aggregate Discharge (Charge), Non-PBI Non-residential Projects, 2015

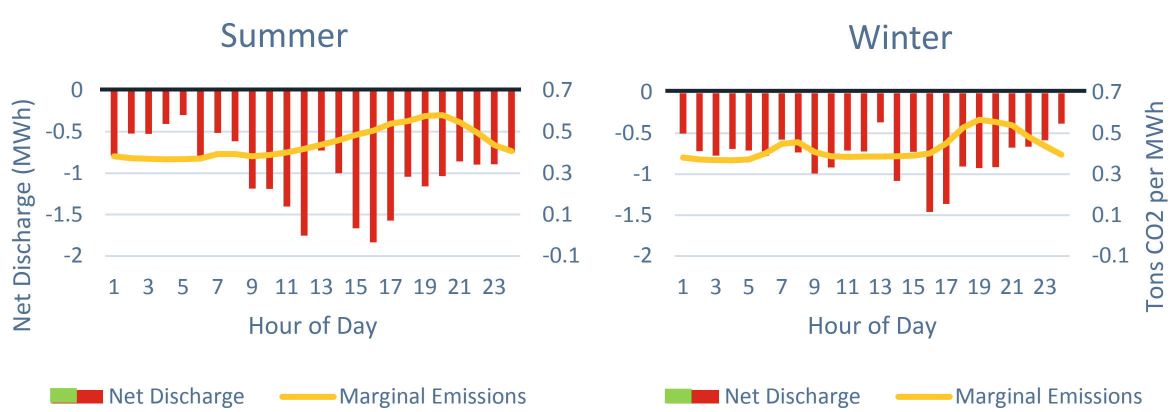


Figure 7-16 shows a strong correlation between discharge timing and marginal emissions for the PBI projects: on average, load is clearly being removed from higher-emitting hours and being shifted to lower-emitting hours. For the non-PBI projects (Figure 7-17), such behavior is not so clear. In fact, non-PBI non-residential storage projects seem to have been, on net, charging during all peak marginal emissions hours in 2015, moving load from lower emitting hours to higher emitting hours. This is partially due to efficiency losses, which we will explore in more detail.

Beyond timing of storage dispatch, another key driver of marginal emissions is that batteries are not 100% efficient. This means that when using storage, more electricity will need to be generated to meet the same amount of electricity demand at a site. This battery inefficiency combined with the fact that charging dispatch timing varies significantly across non-PBI projects means that non-PBI, non-residential storage projects, taken together, display net charging in all hours.

Combining 2015 storage dispatch behavior, storage inefficiencies, and the timing of marginal emissions, we find that both PBI and non-PBI non-residential SGIP storage projects increased CO_2 emissions in 2015. Despite being charged at times when marginal emissions were low, project inefficiencies meant that the 21 observed PBI projects increased emissions by 13 metric tons of CO_2 in 2015. Emissions increases from the 94 observed non-PBI non-residential projects were even more significant, since they were charging during high marginal emissions hours: these 94 projects increased emissions by 19 metric tons of CO_2 in 2015. These results are illustrated in Figure 7-18 and Figure 7-19. Table 7-10 through Table 7-13 summarize the information in these figures. These results only reflect observed AES dispatch: different dispatch algorithms, potentially driven by different incentives could have substantially different results.

Figure 7-18: Total Emissions from Charging and Discharging, PBI Projects, 2015

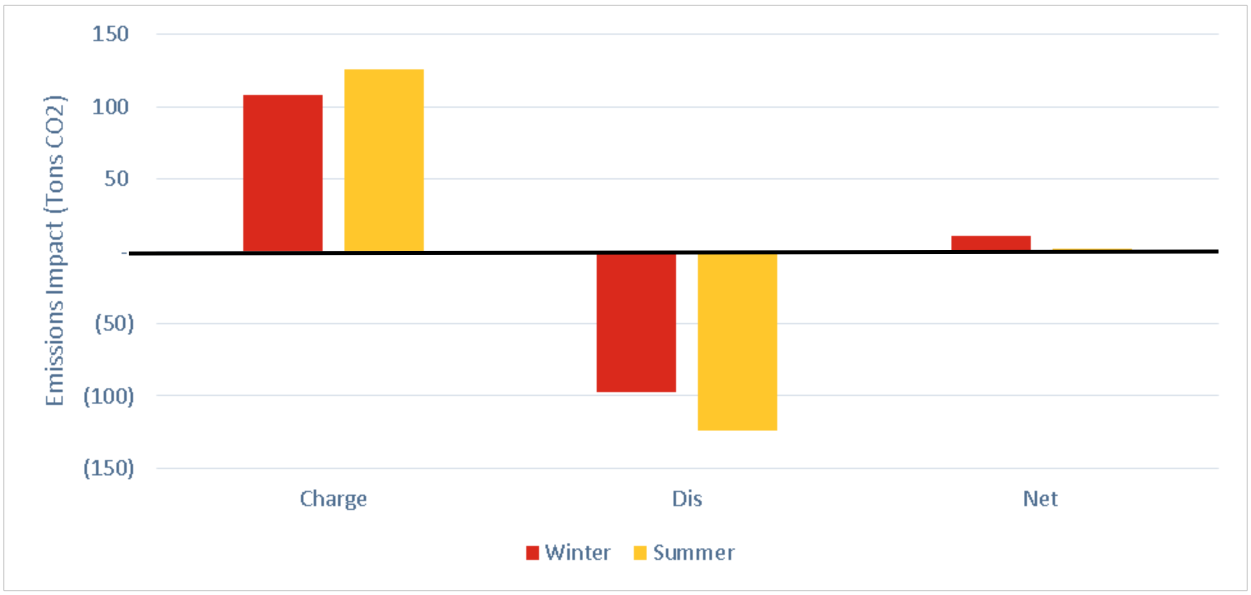


Table 7-10: Emissions Summary from Charging, Observed PBI Projects, 2015

	Summer	Winter
MWh	309	266
Metric tons of CO_2	126	108
Metric tons / MWh	0.41	0.41

Table 7-11: Emissions Summary from Discharging, Observed PBI Projects, 2015

	Summer	Winter
MWh	246	210
Metric tons of CO_2	-124	-97
Metric tons / MWh	-0.50	-0.46

Figure 7-19: Total Emissions from Charging and Discharging, Non-PBI Non-residential Projects, 2015

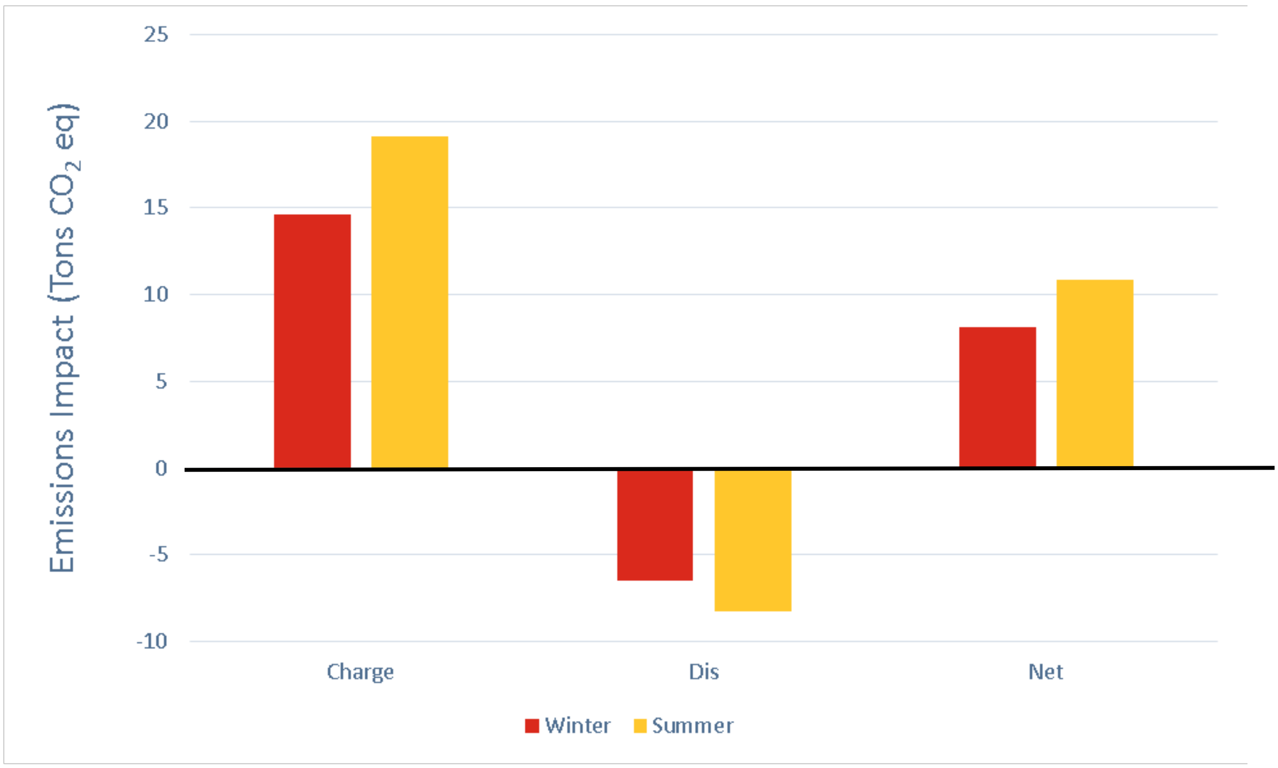


Table 7-12: Emissions Summary from Charging, Observed Non-PBI Non-residential Projects, 2015

	Summer	Winter
MWh	43	35
Metric tons of CO_2	19	15
Metric tons / MWh	0.44	0.42

Table 7-13: Emissions Summary from Discharging, Observed Non-PBI Non-residential Projects, 2015

	Summer	Winter
MWh	20	16
Metric tons of CO_2	-6	-8
Metric tons / MWh	-0.42	-0.41

Extending Sample to Population

Similar to the process used in Section 6 for system peak impacts, we estimated program-wide CO_2 emissions impacts. We created a distribution of emissions per kW of de-rated capacity, defined as in Section 6, for each project, and then calculated a corresponding average program-wide emissions statistic. Program-wide CO_2 emissions impacts for PBI and non-PBI non-residential storage projects are summarized below in Table 7-14.

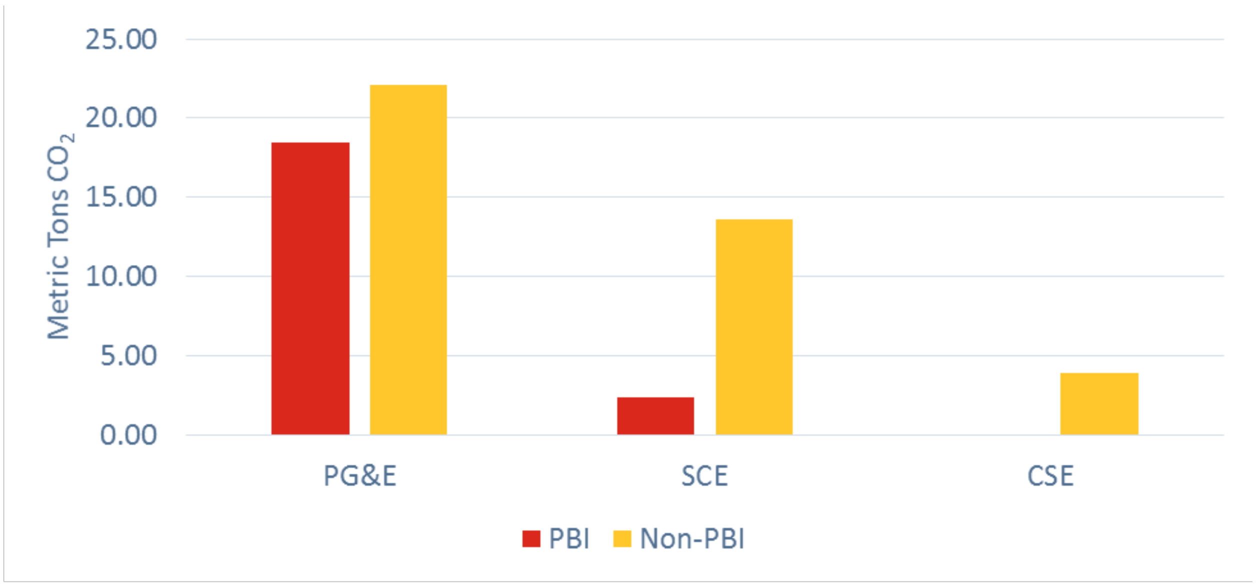
There are significant differences in the amount of storage capacity installed in each PA territory. Recall from Section 6 that there is far more SGIP PBI storage capacity installed in PG&E's territory than SCE's territory. We would therefore expect greater CO_2 impacts in PG&E than SCE. To measure CO_2 impacts on an apples-to-apples basis, we used the same methodology as we applied in Section 6 for coincident peak impacts: we normalized tons of CO_2 by the average de-rated capacity rebated. These figures are shown in parentheses in Table 7-14. For non-PBI projects, there is no significant deviation in this statistic across program administrators. For PBI projects, however, we see that PG&E projects are having a larger GHG contribution per MW of rebated capacity than SCE: PG&E (.003) displays nearly 3 times the emissions per kW de-rated capacity compared to SCE. Again, given such small sample sizes and wide variance, confidence and precision associated with these statistics is low. While one subclass, the aggregate non-PBI subclass, has a precision[2] within 10% using a 90% confidence level, only two other subclasses display 20% precision under an 80% confidence level.

[2] Precision is defined as the ratio of margin of error to sample average, presented in percentage terms.

Table 7-14: Program-Wide Emissions Estimates (tons CO_2) for PBI and Non-PBI projects, 2015[3]

Program administrator	PBI				Non-PBI			
	PG&E	SCE	CSE	Total	PG&E	SCE	CSE	Total[45]
Metric tons CO_2 (parentheses show normalized per rebated kW)	18.5 (0.0031)	2.4 (0.0011)	N/A	21.2 (0.0025)	22.1 (0.017)	13.6 (0.0018)	3.9 (0.0017)	39.0 (0.0017)

Figure 7-20: Program-Wide Emissions Estimates (metric tons CO_2) Across All Non-residential Storage Projects, by Program Administrator, 2015



Given these aggregate dispatch patterns, we were able to infer the theoretical average roundtrip efficiency value needed for the non-residential storage projects to produce carbon neutral impacts if dispatched as observed in 2015. For the PBI projects, these range from 80% (Summer) to 89% (Winter), as shown in Table 7-15. Different dispatch patterns could yield higher or lower RTE's needed to achieve GHG-neutrality or reduction.

3 Note that the PA-level estimates are based on distributions of only the given PA's customers, whereas the Total estimates aggregate all customers across PAs. Thus, these distributions have different variance with different sample sizes, so we do not expect the sum of the estimates by PA to necessarily equal the Total estimate.

4 This is the only subclass of systems that achieves 10% precision around the mean using a 90% confidence interval.

5 Note that the PA-level estimates are based on distributions of only the given PA's customers, whereas the program level estimates aggregate all customers across PAs. Consequently, these distributions have different variances with different sample sizes, leading to different population-level estimates.

Assuming 2015 dispatch patterns, the non-PBI non-residential projects, in aggregate, would increase total emissions even if they were perfectly efficient (100% RTE). This is because, in aggregate, these projects see a higher average emissions rate in the hours that they are charging than those when they are discharging. Recall that there are two issues contributing to the net increase in carbon emissions for the non-PBI data: "poorly timed" charging (the projects charge on average in higher marginal emissions hours and discharge on average in lower marginal emissions hours), and roundtrip losses. Thus, even by completely eliminating the roundtrip losses side of the equation, emissions will still increase on net because of the timing of the charging versus discharging.

Table 7-15: Calculating Theoretical Emissions-Breakeven RTE for Non-residential Storage Projects, Assuming 2015 Storage Dispatch Timing

	Average Emissions from Charging (metric tons/MWh)		Average Emissions from Discharging (metric tons/MWh)		Breakeven Round Trip Efficiency	
	Summer	Winter	Summer	Winter	Summer	Winter
PBI Projects	0.41	0.41	-0.50	-0.46	80%	89%
Non-PBI Projects	0.44	0.42	-0.42	-0.41	105%	102%

Table 7-16 summarizes the net CO_2 emissions increase due to AES, by PA. The first two columns show the increase in CO_2 emissions for PBI and non-PBI projects. The third and fourth columns show annual tons of net CO_2 emissions per kW of rebated AES capacity (metric tons/kW).

Table 7-16: Summary of AES Program-wide CO_2 Emission Increases by PA, 2015

Program Administrator	Tons of CO_2 Emitted		CO_2 Emitted (metric tons)/ Rebated Capacity (kW)	
	PBI	Non-PBI	PBI	Non-PBI
PG&E	18.5	22.1	0.003	.017
SCE	2.4	16.6	0.001	.018
CSE	N/A	4.4	N/A	.017
Total	21.2	42.6	0.003	.017

Program Level Comparisons

8

8 PROGRAM LEVEL COMPARISONS

One purpose of an impact evaluation is to note when observed results vary from expected results. Where possible, impact evaluations can also be helpful in making recommendations on corrective actions to bring the program back towards expected results. In this section, we compare impact results on a program level basis to identify possible sources of issues with program results and determine possible corrective actions.

8.1 Pre- and Post-SB 412 Impacts

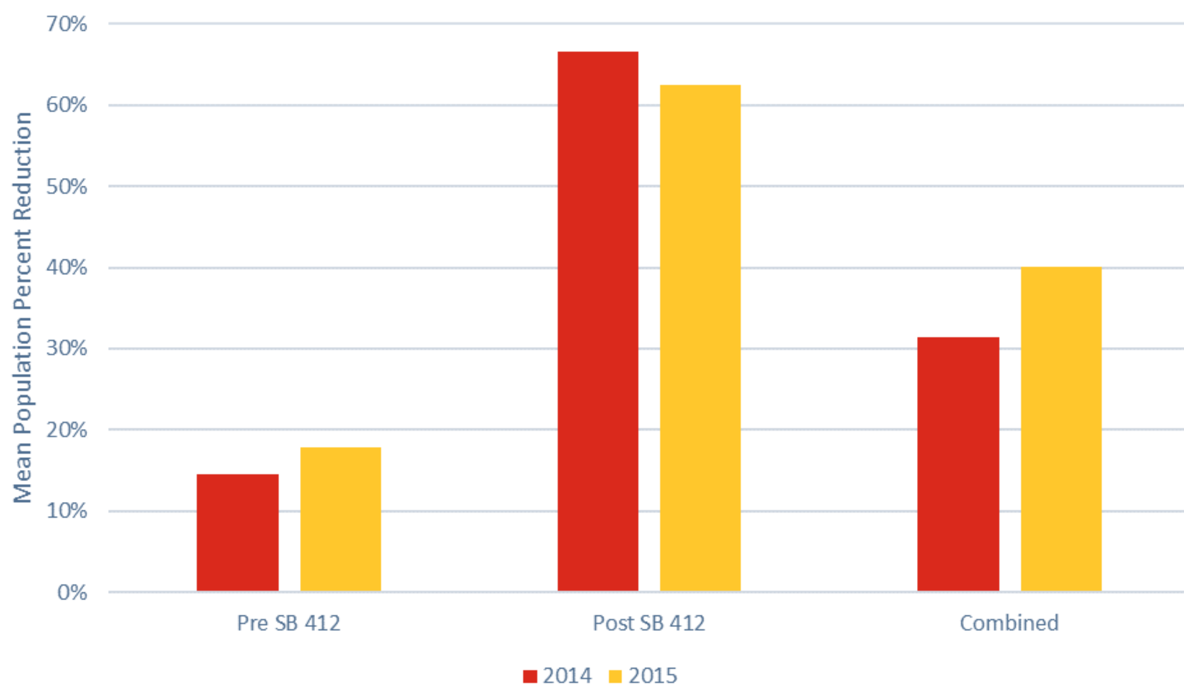
The passage of SB 412 in 2009 resulted in profound changes to the SGIP. Not only did SB 412 refocus the SGIP toward GHG emission reductions, it required fossil fueled combustion technologies to be adequately maintained so they would continue to meet or exceed the established efficiency and emissions standards. However, the classification of SGIP projects into pre-SB 412 and post-SB 412 groups has also led to distinctions in impacts among these groups of projects.

A key metric for operational performance of SGIP technologies is the annual capacity factor. Capacity factor is defined as the amount of energy generated during a given time period divided by the maximum possible amount of energy that could have been generated during that time period. A high capacity factor (near one) for a period indicates that the system is being utilized to its maximum potential. Figure 8-1 shows 2015 annual capacity factors for pre-SB 412 and post-SB 412 non-AES technologies. Generally, post-SB 412 technologies show higher and in some instances, significantly higher annual capacity factors than pre-SB 412 technologies. As pre-SB 412 projects tend to be significantly older than post-SB 412 projects, they can be expected to have more frequent and longer outages; leading to lower annual capacity factors. However, the aging nature of pre-SB 412 projects, with their lower capacity factors also affects other program impacts.

Figure 8-1: 2015 Annual Capacity Factors by Technology and SB 412 Pre/Post

Figure 8-2 presents the aggregate noncoincident customer peak (NCP) demand reduction for the population of non-AES SGIP projects broken out by pre-SB 412 projects versus post-SB 412 projects for both 2014 and 2015. The aggregate NCP demand reductions from post-SB 412 are significantly greater than those from the pre-SB 412 projects. It is likely that more frequent downtime of the older project equipment results in the lower NCP demand reduction associated with the pre-SB 412 projects.

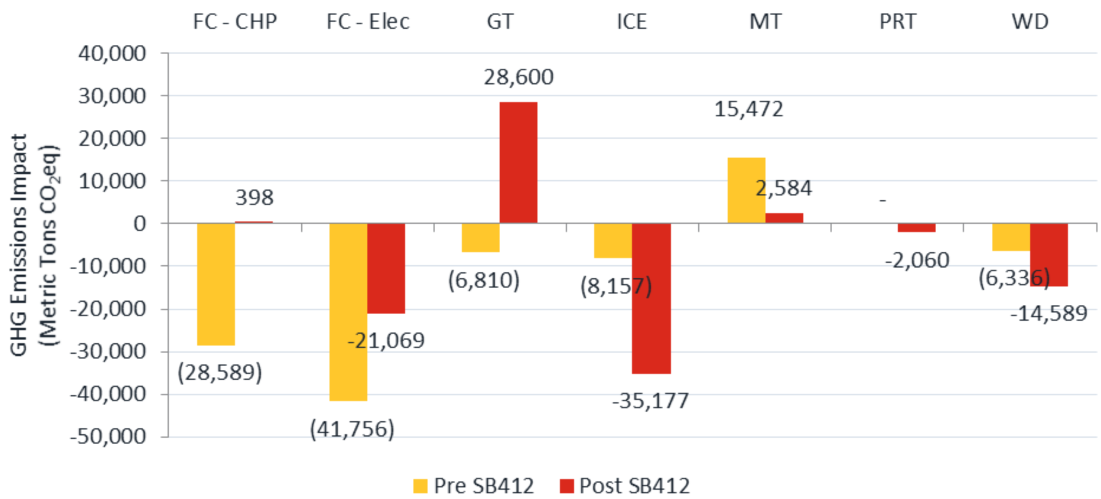
Figure 8-2: Annual NCP Customer Demand Impacts for non-AES Projects; Pre-/Post-SB 412



Because of the importance of GHG emission reductions to the SGIP, we also examined differences in GHG impact between pre and post-SB 412 projects. Figure 8-3 presents a preliminary[1] set of results on GHG impact between pre and post-SB 412 projects.

[1] We have not historically broken out net GHG emission reduction impacts by pre and post-SB 412 categories. In general, when calculating out GHG emission impacts for non-AES technologies, we have assumed projects comply with SGIP requirements and as such have used the same annual capacity factors. We present this preliminary set of results taking into account the difference capacity factors for the pre and post-SB 412 projects but note that a full examination would require additional details on performance that were beyond the scope of this impact evaluation. Note that AES is excluded from this graph since all projects are post-SB 412.

Figure 8-3: 2015 GHG Impact by Technology and Pre-/Post-SB 412 (Preliminary)



For all-electric fuel cells, IC engines and wind energy projects, post-SB 412 projects either have greater net GHG emission reductions than pre-SB 412 projects or at least (in the case of all-electric fuel cells), still maintain a net GHG emission reduction. It is possible that the increased net GHG emission reduction for IC engines is due to the increased number of renewable fuel IC engine projects post-SB 412. Similarly, the lower amount of net GHG emission reduction for all-electric fuel cells for post-SB 412 relative to pre-SB 412 projects is due to the reduced amount of directed biogas for post-SB 412 projects. Post-SB 412 gas turbine projects saw significant increases in emissions impacts due to much lower observed efficiencies among post-SB 412 projects. Regardless of the causes, it appears that there are significant differences in net GHG emission reductions between pre and post-SB 412 projects.

It is apparent that pre-SB 412 projects provide a distinctly different set of impact results from the post-SB 412 projects; and these tend to be tied to the older age of the pre-SB 412 projects or different program requirements. Consequently, as the SGIP moves forward with new projects, retaining pre-SB 412 projects that embed older, non-representative projects could skew the evaluation results.

8.2 Non-AES and AES Impacts

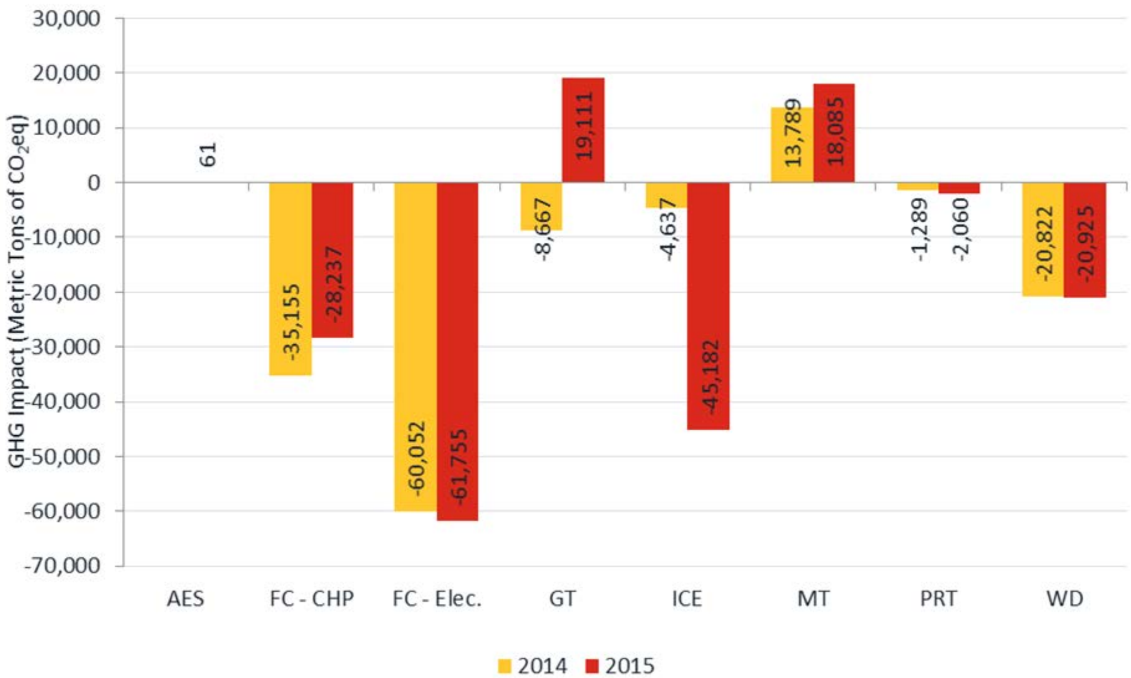
AES technologies have been eligible in the SGIP since Program Year 2008. However, the rapid growth in AES projects and the significant increase in funding for AES makes it important to understand how AES projects compare in performance to non-AES projects. We examine AES and non-AES projects in terms of three of the key program performance metrics: net GHG emission reductions, system peak reduction and aggregate noncoincident customer peak demand reduction.

GHG Emission Reductions for Non-AES vs AES

Figure 8-4 shows the net GHG emission reduction impacts for different SGIP technologies. As pointed out in Section 7, the SGIP overall is reducing GHG emissions. However, as shown in Figure 8-4, the largest net

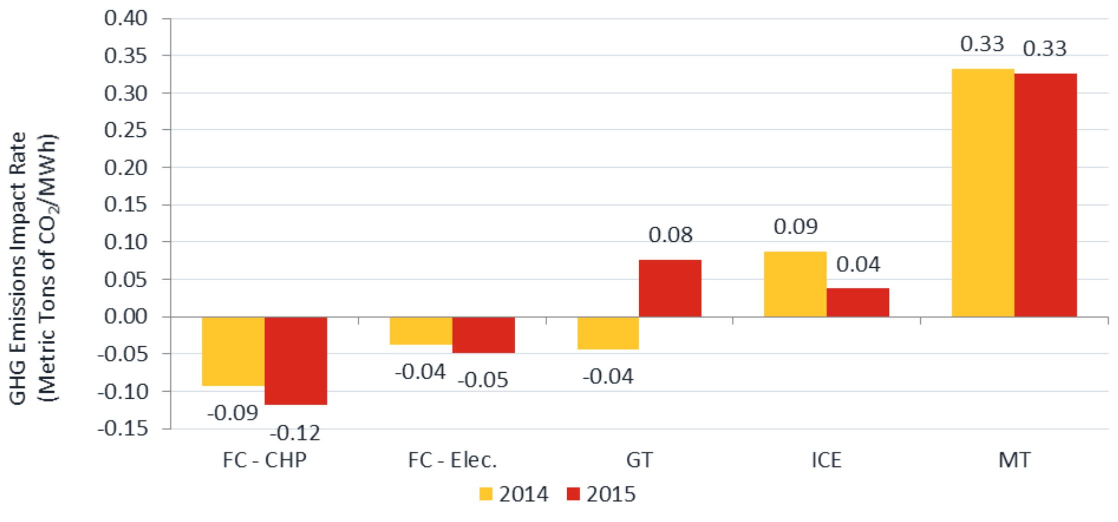
GHG emission reductions are the result of non-AES projects, particularly fuel cell CHP, all-electric fuel cells and IC engines. To some extent, this can be ascribed to the greater total capacity of non-AES projects. In particular, AES projects made up only 4.8% of the SGIP's rebated capacity at the end of 2015.

Figure 8-4: GHG Emission Reductions by Technology



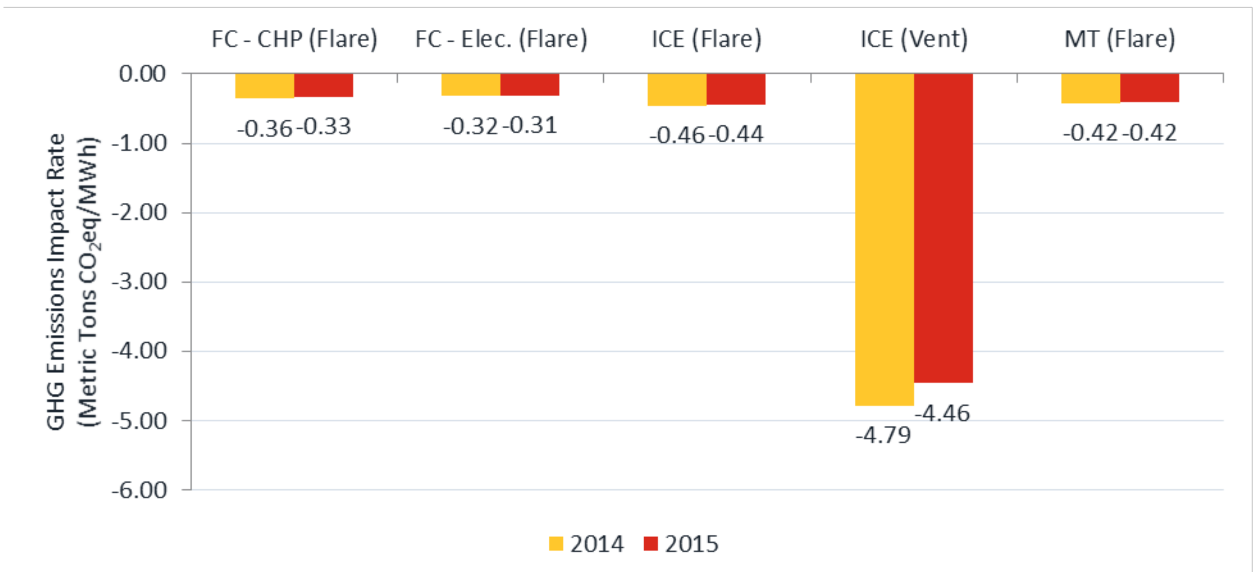
To avoid the bias associated with rebated capacity, we examined the net GHG emission rate impact of non-AES projects versus AES projects. Figure 8-5 shows the GHG impact rate for non-renewable, non-AES projects. In general, the greatest net GHG emission rate reductions occur with fuel cells, whether CHP or all electric. The net reductions range from 0.04 to 0.12 metric tons of CO_2 reduced per MWh.

Figure 8-5: Greenhouse Gas Impact Rate by Technology Type and Calendar Year (Non-renewable Fuel)



However, as we also pointed out in Section 7, renewable fueled projects tended to have the greatest net GHG emission reduction impacts. Figure 8-6 shows the net GHG emission reduction impact for renewable, non-AES projects. All of the renewable, non-AES technologies show net reduction rates ranging in magnitude from 0.32 to 4.79 metric tons of CO_2 reduced per MWh.

Figure 8-6: Renewable Biogas Greenhouse Gas Impact Rates by Technology and Biogas Baseline Type (2014 and 2015)



Lastly, we consider the net GHG emission impact rate for AES. Table 8-1 is a summary of the net GHG emission impact rates for metered non-residential projects. The net GHG emission impact rate is a net increase of 0.07 metric tons of CO_2 generated per MWh discharged.

Table 8-1: Emissions Summary from Discharging, Observed[2] Non-residential Projects, 2015

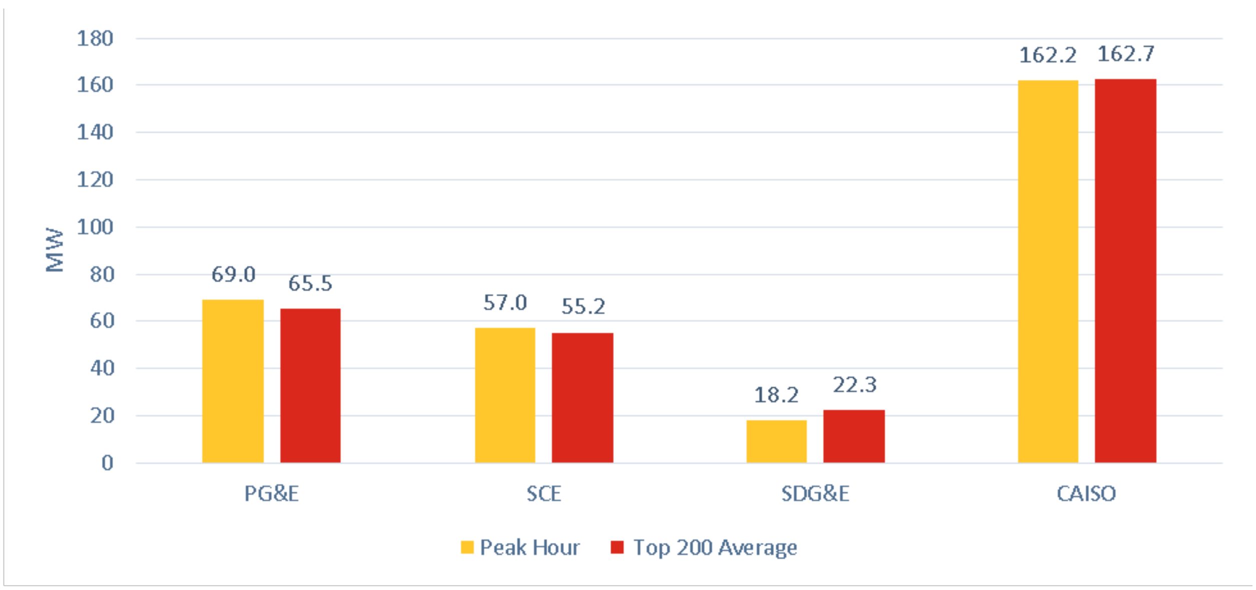
	Summer	Winter
MWh Discharged	266	226
Metric tons of CO_2	+15	+18
Metric tons / MWh	+0.06	+0.08

Based on the net GHG emission impact rates, which remove the bias of total rebated capacity, AES projects show a GHG *increase*. In contrast, many of the non-AES projects show net GHG emission reductions. Moreover, renewable fueled, non-AES projects have a net GHG emission reduction impact rate that has a magnitude anywhere from 5 times to nearly 70 times the GHG emission *increase* impact rate of AES projects. Because AES projects tend to accrue net GHG emission reductions when discharging during peak demand, and there is limited energy discharged during this time, this means there would have to be a substantial increase in effective AES discharge to obtain the equivalent net GHG emission reductions provided by renewable fueled, non-AES projects.

Coincident Peak Demand Reduction for Non-AES vs AES

SGIP was created initially as a peak demand reduction program. From a CAISO or utility perspective, SGIP projects should therefore generate (or in the case of AES, discharge) electricity during system peak hours to help offset the need for utilities to generate power during the peak. Figure 8-7 shows the contribution of non-AES projects during the utility and CAISO top peak hour and the top 200 hours for 2015.

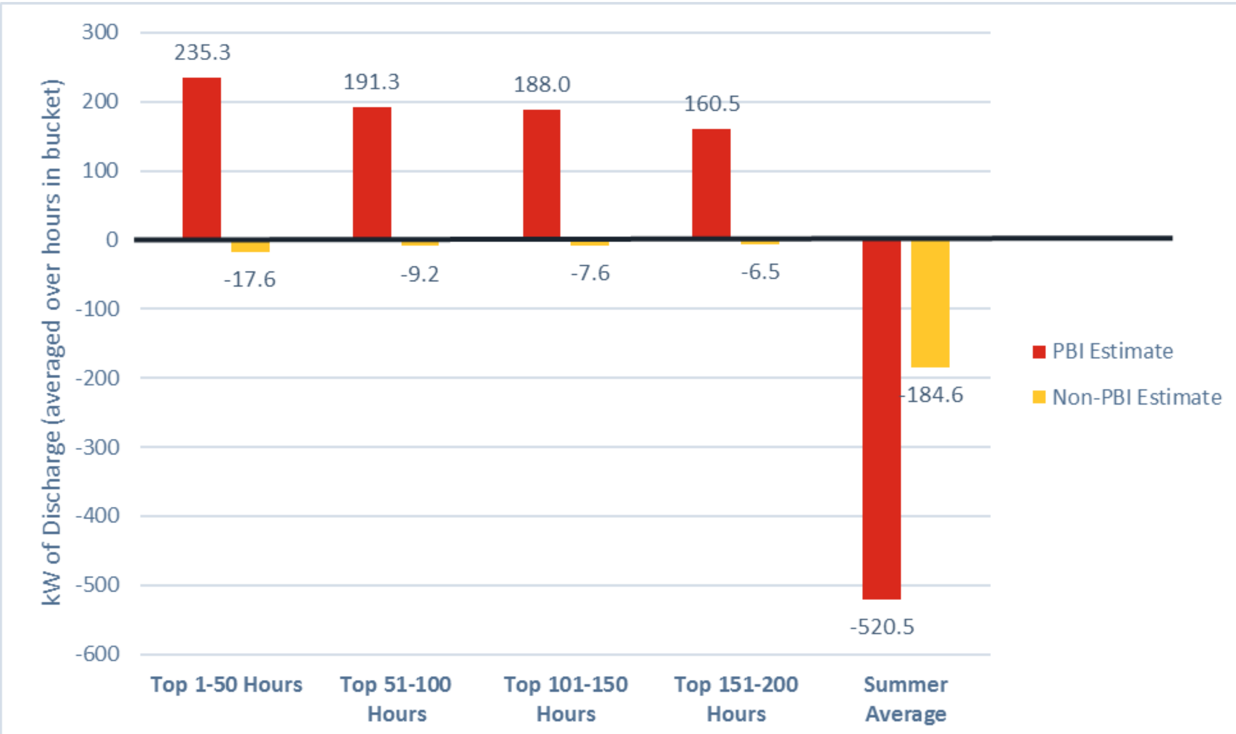
Figure 8-7: 2015 CAISO and IOU Peak and Top 200 Peak Hour Generation for SGIP non-AES Projects



2 Not population, only metered projects

Figure 8-8 is a similar depiction of how AES projects contribute to the coincident CAISO top peak and top 200 peak hours for 2015.

Figure 8-8: Estimate of Population-Level System Peak Impacts, Compared to Summer Average, Non-Residential Storage Projects, 2015

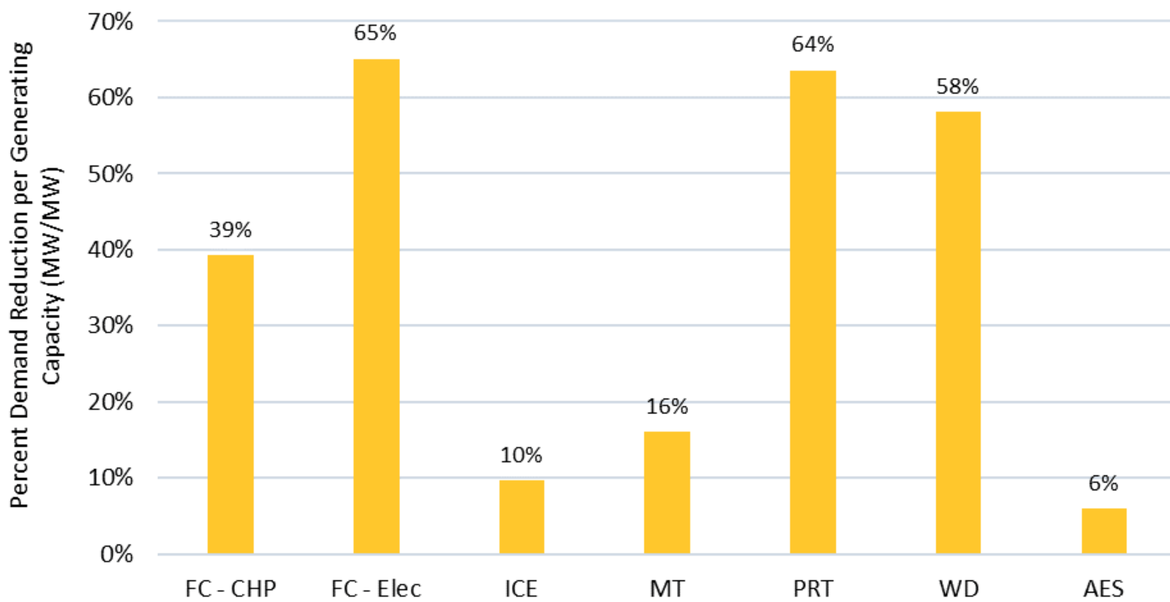


Both figures present total contributions in the case of non-AES in MW and for AES in kW. However, AES projects only make up 4.2% of the total rebated capacity of the SGIP. Therefore, to compare these coincident peak demand impacts, we place these on a per MW of rebated capacity basis. At the end of 2015, non-AES projects represented approximately 419 MW of rebated capacity, whereas AES projects represented approximately 21 MW of rebated capacity. If we only look at the CAISO peak hour impact, the contribution of non-AES projects is, on average approximately 0.39 MW of peak contribution/MW of rebated capacity (i.e., 162.7 MW of peak/419 MW of rebated capacity). In comparison, the contribution of AES projects is approximately 0.01 MW of peak contribution/ MW of rebated capacity (i.e., 235 kW of peak/21 MW of rebated capacity). These are approximations and more detailed analysis based on additional data is needed to fully examine coincident peak comparisons. However, based on the data available and how AES projects are currently operated, it appears that AES projects provide significantly less coincident peak demand relief than their non-AES counterparts on a rebated capacity basis.

Noncoincident Customer Peak Demand Reduction for Non-AES vs AES

SB 861 requires that the CPUC evaluate the SGIP impact on aggregate noncoincident customer peak demand. In essence, this requirement examines the value of an SGIP project to the host customer. Because the SGIP represents only 0.5% of California's total in-state generation capacity, the ability of the SGIP to influence the state's total peak demand is limited. However, because each SGIP project can represent a significant portion of the host customer's peak demand, the aggregate noncoincident customer peak demand impact of SGIP can have much more effect on individual customers. Figure 8-9 shows the aggregate noncoincident customer peak demand reduction impacts of AES projects versus non-AES projects. However, in order to reduce bias associated with comparing older aged projects to newer projects, we examine only post-SB 412 non-AES project impacts.

Figure 8-9: Aggregate Noncoincident Customer Peak Demand Reduction in 2015 for Non-AES (Post-SB 412) and AES Projects



Based on the available data and how AES projects are currently operated, post-SB 412 non-AES projects provide greater peak demand relief to customers than AES projects. In fact, most of the non-AES technologies, except for IC engines and microturbines, show significantly higher aggregate noncoindent customer peak demand reduction than AES. However, normalizing reductions on a per rebated kW basis could be argued to not be fully equitable between non-AES and AES technologies since AES projects are rated on the 2-hour discharge capability. Therefore, AES cannot be reasonably expected to achieve peak reductions near 100% unless the customer peak is very short. Nevertheless, more than a single digit percent reduction should be obtainable with more optimal discharge. Moreover, the intent of AES operation should be focused on helping to achieve peak demand relief for both utilities and customers, which requires a fundamentally different approach from requiring more than a 2-hour discharge capability.

Arguably, this data is limited and if more customer demand data were available and could be matched to AES charge/discharge data and non-AES project generation data, the results could be different. Nonetheless, policy makers who are evaluating performance of the SGIP and deciding how to structure the SGIP moving forward have not even had this information available to them prior to this impact evaluation.

8.3 GHG Impact Estimates and GHG Build Margin-Based Estimates

SB 412 refocused the SGIP such that a primary goal of the program is to achieve net GHG emission reductions. In Decision (D.) 15-11-026 (November 19, 2015), the California Public Utilities Commission (CPUC) revised the GHG emission factor to determine eligibility to participate in the Self-Generation Incentive Program (SGIP) pursuant to Public Utilities Code Section 379.6(b)(2) as amended by Senate Bill (SB) 861. Subsequently, the CPUC directed Itron to incorporate the methodology discussion in this Decision into the 2014-2015 SGIP Impact Evaluation Report. The build margin approach assumes that renewable capacity is displaced after a project's fifth year of operation. Consequently, the avoided emissions rate becomes lower for older projects, which leads to a reduction in the GHG impact (less benefit). Figure 8-10 shows the comparison of the net GHG emission reduction impact using an approach that does not take into account the build margin and an approach that incorporates the build margin.

Figure 8-10: Comparison of SGIP Emission Impact to Build Margin Scenario

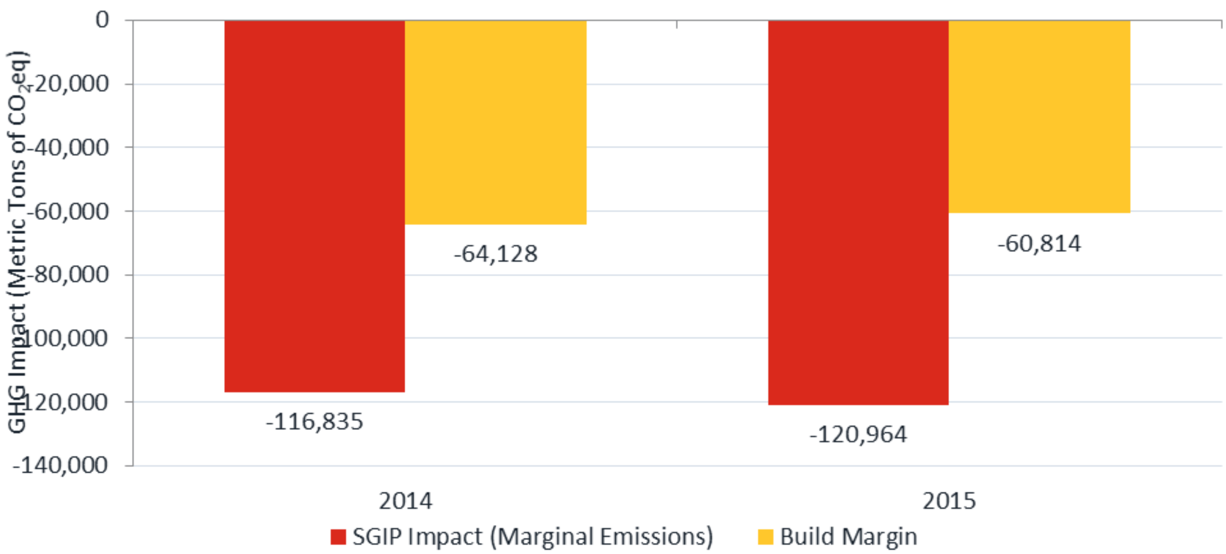
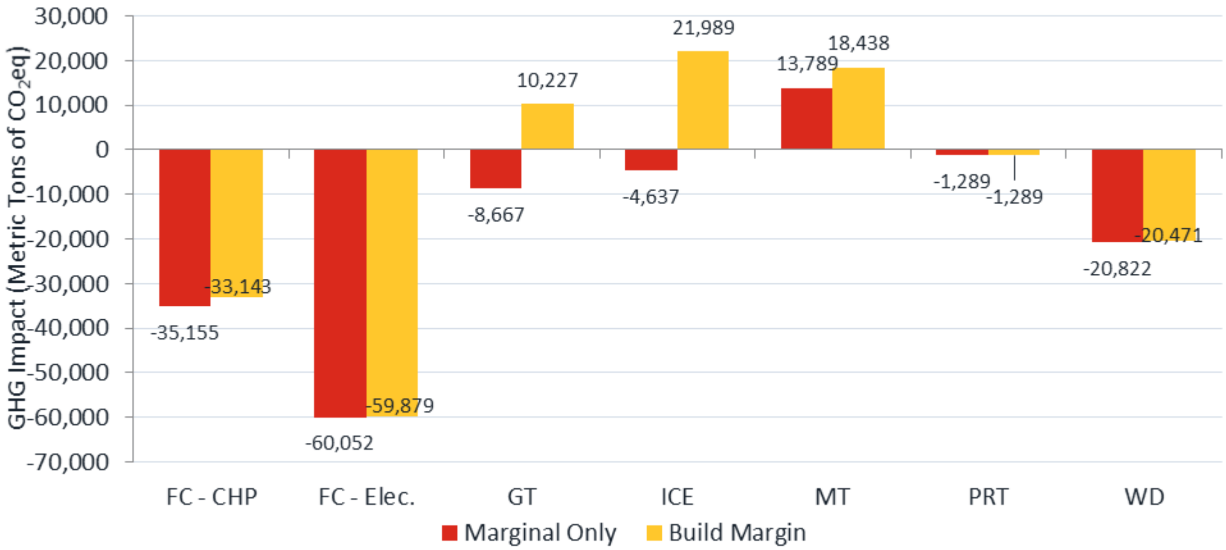


Figure 8-11 further breaks down the comparison of net GHG emissions using the "marginal only" versus "build margin" approaches at the technology level.

Figure 8-11: Comparison of 2014 GHG Impact to Build Margin Scenario by Technology



Overall, the effect of taking the build margin into account is an effective lowering of the SGIP's ability to lower net GHG emissions. However, as we pointed out in Section 7, because the build margin effect manifests itself after the fifth year of operation, the impact is more pronounced for technologies that have been in the SGIP for longer periods of time. Moving forward, if the SGIP is evaluated using on post-SB 412 projects to ensure an "apples to apples" comparison of technologies with similar ages, this essentially eliminates use of the build margin approach for pre-SB 412 projects until 2017-2018. As noted at the very start of Section 8, we examined the impact of pre and post-SB 412 projects on net GHG emission reductions. As depicted in Figure 8-3, the overall impact of eliminating pre-SB 412 projects and hence the build margin, is that the SGIP still is an overall GHG emissions reducing program.

Appendix A

APPENDIX A PROGRAM STATISTICS

This appendix provides detailed Self-Generation Incentive Program (SGIP) statistics beyond the tables and figures included in Section 3.

A.1 Program Statistics at End of 2015

By the end of 2015, the SGIP had paid incentives to 1144 projects representing almost 443.1 MW of rebated capacity. Table A-1 shows counts and rebated capacities of completed projects for each Program Administrator (PA).

Table A-1: Project Counts and Rebated Capacity by Program Administrator

Program Administrator	Project Count	Rebated Capacity (MW)	Percent of Rebated Capacity
CSE	127	44.8	10.2%
PG&E	612	188.9	42.9%
SCE	233	99	22.5%
SCG	172	107.4	24.4%
Total	***1,144***	***440.2***	***100%***

* CSE = Center for Sustainable Energy, PG&E = Pacific Gas & Electric, SCE = Southern California Edison, SCG = Southern California Gas Company

The SGIP provides incentives for a variety of different technologies. Table A-2 shows project counts and rebated capacities of completed projects by technology type.

Table A-2: Project Counts and Rebated Capacity by Technology Type

Technology Type	Project Count	Rebated Capacity (MW)	Percent of Rebated Capacity
Advanced Energy Storage	343	21.3	4.8%
Fuel Cell – CHP	121	37.0	8.4%
Fuel Cell - Electric Only	215	98.5	22.4%
Gas Turbine	11	44.3	10.1%
Internal Combustion Engine	277	178.3	40.5%
Microturbine	150	31.4	7.1%
Pressure Reduction Turbine	2	1.1	0.2%
Wind Turbine	25	28.3	6.4%
Total	***1,144***	***440.2***	***100%***

Beginning in program year (PY) 2011, the SGIP implemented an incentive structure where projects 30 kW and larger will receive half of their incentive payment upfront and the remainder of the incentive during the first five years of operation. This mechanism is known as a Performance Based Incentive (PBI). Paid projects are classified as having a capacity incentive or a PBI incentive. Table A-3 shows project counts and rebated capacities of completed projects by technology type and incentive payment mechanism.

Table A-3: Project Counts and Rebated Capacity by Technology Type and Payment Mechanism

System Type	Capacity Incentive		PBI Incentive	
	MW	Count	MW	Count
Advanced Energy Storage	5.3	314	16.0	29
Fuel Cell – CHP	33.8	116	3.2	5
Fuel Cell – Electric Only	41.2	90	57.3	125
Gas Turbine	30.1	9	14.2	2
Internal Combustion Engine	156.5	256	21.8	21
Microturbine	25.6	142	5.8	8
Pressure Reduction Turbine	-	-	1.1	2
Wind Turbine	13.3	17	15.0	8
Total	***305.9***	***944***	***134.3***	***200***

In an effort to recognize significant changes in program policy, this report further classifies projects as Pre-SB 412 and Post-SB 412 based on their program year. Paid projects that applied to the SGIP during PY01-PY10 are classified as Pre-SB 412. Paid projects that applied during or after PY11 (regardless of their incentive payment mechanism) are classified as Post-SB 412. This classification scheme is intended to allow comparisons between the two groups to identify changes in project performance. Table A-4 shows project counts and rebated capacities of paid projects by technology type and Pre-/post-SB 412 status.

Table A-4: Project Counts and Rebated Capacity by Technology Type and Pre-/Post-SB 412 Status

System Type	Pre-SB 412		Post-SB 412	
	MW	Count	MW	Count
Advanced Energy Storage	1.6	2	19.7	341
Fuel Cell - CHP	33.7	110	3.3	11
Fuel Cell - Electric Only	40.7	89	57.8	126
Gas Turbine	30.1	9	14.2	2
Internal Combustion Engine	156.5	256	21.8	21
Microturbine	25.6	142	5.8	8
Pressure Reduction Turbine	-	-	1.1	2
Wind	13.3	15	15.1	10
Total	***301.5***	***623***	***138.7***	***521***

Table A-5 shows that SGIP projects are powered by a variety of renewable and non-renewable energy sources. The majority of SGIP projects are powered by non-renewable fuels such as natural gas. On-site biogas projects typically use biogas derived from landfills or anaerobic digestion processes that convert biological matter to a renewable fuel source. Anaerobic digesters are used at dairies, wastewater treatment plants, or food processing facilities to convert wastes from these facilities to biogas. Directed biogas projects purchase biogas fuel that is produced at a location other than the project site. The 'Other' energy source group includes advanced energy storage, wind turbine, and pressure reduction turbine projects. There is one pressure reduction turbine project completed in the SGIP. This project is installed at a water treatment plant and is powered by water from a nearby lake.

Table A-5: Project Counts and Rebated Capacity by Technology Type and Energy Source

System Type	Energy Source	Project Count	Rebated Capacity (MW)	Percent of Rebated Capacity
Advanced Energy Storage	None	343	21.3	4.8%
Fuel Cell - CHP	Non-Renewable	100	18.0	4.1%
	Biogas (Onsite Blended)	14	11.9	2.7%
	Biogas (Onsite Only)	1	0.3	0.1%
	Biogas (Directed)	6	6.9	1.6%
Fuel Cell - Electric Only	Non-Renewable	157	73.8	16.8%
	Biogas (Directed)	58	24.7	5.6%
Gas Turbine	Non-Renewable	11	44.3	10.1%
Internal Combustion Engine	Non-Renewable	235	147.9	33.6%
	Biogas (Onsite Blended)	15	13.1	3.0%
	Biogas (Onsite Only)	27	17.2	3.9%
Microturbine	Non-Renewable	122	25.3	5.7%
	Biogas (Onsite Blended)	4	1.0	0.2%
	Biogas (Onsite Only)	24	5.2	1.2%
Pressure Reduction Turbine	Other	2	1.1	0.2%
Wind Turbine	Other	25	28.3	6.4%
Total		***1,144***	***440.2***	***100%***

Combined heat and power (CHP) projects can recover useful heat to serve heating loads such as process hot water or cooling loads by use of an absorption chiller. The useful heat end use has important implications for natural gas distribution impacts and consequently greenhouse gas emissions impacts. Table A-6 summarizes the useful heat end uses observed in the SGIP.

Table A-6: Project Counts and Capacities by Useful Heat End Use

Useful Heat End Use	Project Count with Useful Heat Recovery	Rebated Capacity with Useful Heat Recovery (MW)	Percent of Rebated Capacity with Useful Heat Recovery*
Cooling Only	43	41.5	15.1%
Heating Only	393	161.1	58.5%
Cooling + Heating	92	72.8	26.4%
Total	***528***	***275.4***	***100%***

* Total project count and rebated capacity in this table excludes advanced energy storage, electric-only fuel cell, pressure reduction turbine, and wind projects.

By the end of 2015, the SGIP paid or reserved over $660 million in incentives. Eligible costs reported by applicants surpassed $2.3 billion. Table A-7 shows the breakdown of incentives paid by the SGIP and costs reported by applicants for each technology type. The leverage ratio, calculated as the ratio of SGIP participant investment to SGIP incentives, is one financial measure of the SGIP's effectiveness in accelerating development of markets for distributed energy resources.

Table A-7: Incentives Paid, Reported Costs, and Leverage Ratio by Technology Type

System Type	Rebated Capacity (MW)	SGIP Incentive (Nominal $MM)	Eligible Costs (Nominal $ MM)	Leverage Ratio
Advanced Energy Storage	21.3	37.6	77.8	1.07
Fuel Cell - CHP	37.0	113.4	285.2	1.51
Fuel Cell - Electric Only	98.5	317.5	1,121.4	2.53
Gas Turbine	44.3	8.4	119.2	13.23
Internal Combustion Engine	178.3	126.0	465.2	2.69
Microturbine	31.4	27.4	117.0	3.27
Pressure Reduction Turbine	1.1	1.3	4.7	2.58
Wind Turbine	28.3	33.9	113.7	2.35
Total	***440.2***	***665.6***	***2,304.2***	***2.46***

SGIP projects are electrically interconnected to load serving entities that are either investor owned (IOU) or municipal utilities. Table A-8 shows each PA's rebated capacity by electric utility type and technology type. Over 93% of rebated capacity was interconnected to investor owned electric utilities.

Table A-8: Electric Utility Type by Program Administrator and Technology Type

Program Administrator / Electric Utility Type		Rebated Capacity (MW)								
		Advanced Energy Storage	Fuel Cell - CHP	Fuel Cell - Electric Only	Gas Turbine	Internal Combustion Engine	Microturbine	Pressure Reduction Turbine	Wind	All Projects
CSE	IOU	0.6	8.1	7.8	13.7	11.3	1.9	0.5	1.0	***44.8***
	Municipal	-	-	-	-	-	-	-	-	***-***
PG&E	IOU	14.0	12.0	46.5	13.6	72.4	14.5	0.6	12.2	***185.8***
	Municipal	0.1	-	1.8	-	1.2	-	-	-	***3.1***
SCE	IOU	6.0	7.0	25.0	-	38.1	7.9	-	15.1	***99.0***
	Municipal	-	-	-	-	-	-	-	-	***-***
SCG	IOU	0.6	4.9	1.0	17.0	52.5	4.9	-	-	***80.9***
	Municipal	0.0	5.0	16.4	-	2.9	2.2	-	-	***26.5***
Total		***21.3***	***37.0***	***98.5***	***44.3***	***178.3***	***31.4***	***1.1***	***28.3***	***440.2***

A.2 Trends in Program Statistics

The date a project is issued its upfront incentive payment is used as a proxy for the date it enters normal operations and begins to accrue impacts. Table A-9 and Table A-10 show project counts and capacities by technology type and upfront payment year. Table A-9 shows annual counts and capacities while Table A-10 shows cumulative counts and capacities.

Table A-9: Project Counts and Rebated Capacity by Technology Type and Upfront Payment Year

Upfront Payment Year / Project Count and Rebated Capacity		Advanced Energy Storage	Fuel Cell - CHP	Fuel Cell - Electric Only	Gas Turbine	Internal Combustion Engine	Microturbine	Pressure Reduction Turbine	Wind	All Projects
2001	Count	-	-	-	-	-	-	-	-	**-**
	Capacity (MW)	-	-	-	-	-	-	-	-	**-**
2002	Count	-	1	-	-	6	3	-	-	***10***
	Capacity (MW)	-	0.2	-	-	4.0	0.3	-	-	***4.4***
2003	Count	-	-	-	-	35	21	-	-	***56***
	Capacity (MW)	-	-	-	-	22.2	2.5	-	-	***24.7***
2004	Count	-	1	-	1	51	25	-	-	***78***
	Capacity (MW)	-	0.6	-	1.4	35.2	3.9	-	-	***41.1***
2005	Count	-	3	-	1	31	33	-	2	***70***
	Capacity (MW)	-	1.8	-	1.2	19.4	5.3	-	1.6	***29.4***
2006	Count	-	7	-	2	62	27	-	-	***98***
	Capacity (MW)	-	4.0	-	9.0	36.3	5.0	-	-	***54.2***
2007	Count	-	2	-	1	23	14	-	-	***40***
	Capacity (MW)	-	1.5	-	1.4	12.7	1.7	-	-	***17.3***
2008	Count	-	6	-	1	20	11	-	-	***38***
	Capacity (MW)	-	3.9	-	4.6	13.5	3.5	-	-	***25.4***
2009	Count	-	3	2	2	9	3	-	2	***21***
	Capacity (MW)	-	2.1	0.7	8.1	4.7	1.7	-	0.3	***17.5***
2010	Count	-	6	6	-	12	3	-	4	***31***
	Capacity (MW)	-	2.0	2.2	-	5.3	0.4	-	2.8	***12.7***

Upfront Payment Year / Project Count and Rebated Capacity		Advanced Energy Storage	Fuel Cell - CHP	Fuel Cell - Electric Only	Gas Turbine	Internal Combustio n Engine	Microturbine	Pressure Reduction Turbine	Wind	All Projects
2011	Count	-	56	39	-	6	1	-	2	***104***
	Capacity (MW)	-	8.1	15.6	-	3.0	0.8	-	2.1	***29.5***
2012	Count	2	24	38	1	1	1	-	4	***71***
	Capacity (MW)	1.6	6.9	20.8	4.4	0.3	0.8	-	3.6	***38.3***
2013	Count	3	5	39	-	1	-	1	6	***55***
	Capacity (MW)	0.3	3.3	17.1	-	1.0	-	0.5	13.4	***35.6***
2014	Count	58	4	24	-	4	6	-	2	***98***
	Capacity (MW)	3.6	0.4	15.1	-	3.0	2.8	-	1.0	***24.9***
2015	Count	280	3	67	2	16	2	1	3	***374***
	Capacity (MW)	16.9	2.4	27.0	14.2	17.9	3.0	0.6	3.6	***85.5***
Total	***Count***	***343***	***121***	***215***	***11***	***277***	***150***	***2***	***25***	***1,144***
	Capacity (MW)	***21.3***	***37.0***	***98.5***	***44.3***	***178.3***	***31.4***	***1.1***	***28.3***	***440.2***

Table A-10: Cumulative Project Counts and Rebated Capacity by Technology Type and Upfront Payment Year

Upfront Payment Year / Cumulative Project Count and Rebated Capacity		Advanced Energy Storage	Fuel Cell - CHP	Fuel Cell - Electric Only	Gas Turbine	Internal Combustion Engine	Microturbine	Pressure Reduction Turbine	Wind	All Projects
2001	Count	0	0	0	0	0	0	0	0	***0***
	Capacity (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	***0.0***
2002	Count	0	1	0	0	6	3	0	0	***10***
	Capacity (MW)	0.0	0.2	0.0	0.0	4.0	0.3	0.0	0.0	***4.4***
2003	Count	0	1	0	0	41	24	0	0	***66***
	Capacity (MW)	0.0	0.2	0.0	0.0	26.1	2.7	0.0	0.0	***29.1***
2004	Count	0	2	0	1	92	49	0	0	***144***
	Capacity (MW)	0.0	0.8	0.0	1.4	61.3	6.6	0.0	0.0	***70.1***
2005	Count	0	5	0	2	123	82	0	2	***214***
	Capacity (MW)	0.0	2.6	0.0	2.6	80.7	11.9	0.0	1.6	***99.5***
2006	Count	0	12	0	4	185	109	0	2	***312***
	Capacity (MW)	0.0	6.5	0.0	11.6	117.0	16.9	0.0	1.6	***153.7***
2007	Count	0	14	0	5	208	123	0	2	***352***
	Capacity (MW)	0.0	8.0	0.0	13.0	129.7	18.6	0.0	1.6	***170.9***
2008	Count	0	20	0	6	228	134	0	2	***390***
	Capacity (MW)	0.0	11.9	0.0	17.6	143.1	22.0	0.0	1.6	***196.4***
2009	Count	0	23	2	8	237	137	0	4	***411***
	Capacity (MW)	0.0	14.0	0.7	25.7	147.8	23.7	0.0	1.9	***213.9***
2010	Count	0	29	8	8	249	140	0	8	***442***
	Capacity (MW)	0.0	16.0	2.9	25.7	153.1	24.1	0.0	4.7	***226.6***
2011	Count	0	85	47	8	255	141	0	10	***546***
	Capacity (MW)	0.0	24.0	18.5	25.7	156.1	24.9	0.0	6.8	***256.0***
2012	Count	2	109	85	9	256	142	0	14	***617***
	Capacity (MW)	1.6	30.9	39.2	30.1	156.5	25.6	0.0	10.3	***294.3***
2013	Count	5	114	124	9	257	142	1	20	***672***

Upfront Payment Year / Cumulative Project Count and Rebated Capacity		Advanced Energy Storage	Fuel Cell - CHP	Fuel Cell - Electric Only	Gas Turbine	Internal Combustion Engine	Microturbine	Pressure Reduction Turbine	Wind	All Projects
	Capacity (MW)	1.9	34.2	56.4	30.1	157.4	25.6	0.5	23.7	***329.9***
2014	Count	63	118	148	9	261	148	1	22	***770***
	Capacity (MW)	4.5	34.6	71.4	30.1	160.4	28.4	0.5	24.7	***354.8***
2015	Count	343	121	215	11	277	150	2	25	***1144***
	Capacity (MW)	21.3	37.0	98.5	44.3	178.3	31.4	1.1	28.3	***440.2***

A project's program year is used to determine what program rules and policies are applicable to it. Table A- 11 and Table A-12 list project counts and rebated capacities by program year and technology type for projects paid on or before December 31, 2015. Table A- 11 shows annual counts and capacities. Table A-12 shows cumulative counts and capacities.

Table A- 11: Project Counts and Rebated Capacity by Technology Type and Program Year

Program Year / Project Count and Rebated Capacity		Advanced Energy Storage	Fuel Cell - CHP	Fuel Cell - Electric Only	Gas Turbine	Internal Combustion Engine	Microturbine	Pressure Reduction Turbine	Wind	All Projects
PY01	Count	0	1	0	0	27	21	0	0	***49***
	Capacity (MW)	0.0	0.2	0.0	0.0	14.7	2.8	0.0	0.0	***17.7***
PY02	Count	0	1	0	1	54	17	0	0	***73***
	Capacity (MW)	0.0	0.6	0.0	1.4	36.5	2.9	0.0	0.0	***41.4***
PY03	Count	0	2	0	1	54	40	0	2	***99***
	Capacity (MW)	0.0	0.8	0.0	1.2	37.5	5.0	0.0	1.6	***46.1***
PY04	Count	0	3	0	1	49	30	0	0	***83***
	Capacity (MW)	0.0	2.3	0.0	1.4	24.6	5.7	0.0	0.0	***33.9***
PY05	Count	0	6	0	2	31	14	0	0	***53***
	Capacity (MW)	0.0	3.7	0.0	9.0	22.4	3.1	0.0	0.0	***38.2***
PY06	Count	0	7	0	3	17	13	0	0	***40***
	Capacity (MW)	0.0	5.1	0.0	12.7	11.2	4.1	0.0	0.0	***33.1***
PY07	Count	0	2	1	1	24	7	0	2	***37***
	Capacity (MW)	0.0	0.8	0.4	4.4	9.6	2.1	0.0	1.2	***18.4***
PY08	Count	0	6	0	0	0	0	0	1	***7***
	Capacity (MW)	0.0	0.6	0.0	0.0	0.0	0.0	0.0	0.2	***0.9***
PY09	Count	1	18	8	0	0	0	0	3	***30***
	Capacity (MW)	1.0	7.3	2.7	0.0	0.0	0.0	0.0	1.6	***12.6***
PY10	Count	1	64	80	0	0	0	0	7	***152***
	Capacity (MW)	0.6	12.4	37.6	0.0	0.0	0.0	0.0	8.6	***59.2***
PY11	Count	15	3	19	0	1	1	0	5	***44***
	Capacity (MW)	0.2	0.8	12.2	0.0	0.7	0.7	0.0	10.5	***25.1***
PY12	Count	147	6	39	2	15	7	2	3	***221***
	Capacity (MW)	6.3	0.5	17.3	14.2	20.2	5.1	1.1	3.6	***68.1***

Program Year / Project Count and Rebated Capacity		Advanced Energy Storage	Fuel Cell - CHP	Fuel Cell - Electric Only	Gas Turbine	Internal Combustion Engine	Microturbine	Pressure Reduction Turbine	Wind	All Projects
PY13	Count	50	2	28	0	2	0	0	2	***84***
	Capacity (MW)	5.2	2.0	18.2	0.0	0.4	0.0	0.0	1.0	***26.9***
PY14	Count	125	0	39	0	2	0	0	0	***166***
	Capacity (MW)	7.8	0.0	9.0	0.0	0.3	0.0	0.0	0.0	***17.1***
PY15	Count	4	0	1	0	1	0	0	0	***6***
	Capacity (MW)	0.3	0.0	1.1	0.0	0.3	0.0	0.0	0.0	***1.6***
Total	***Count***	***343***	***121***	***215***	***11***	***277***	***150***	***2***	***25***	***1144***
	Capacity (MW)	***21.3***	***37.0***	***98.5***	***44.3***	***178.3***	***31.4***	***1.1***	***28.3***	***440.2***

Table A-12: Cumulative Project Counts and Rebated Capacity by Technology Type and Program Year

Program Year / Cumulative Project Count and Rebated Capacity		Advanced Energy Storage	Fuel Cell - CHP	Fuel Cell - Electric Only	Gas Turbine	Internal Combustion Engine	Microturbine	Pressure Reduction Turbine	Wind	All Projects
PY01	Count	0	1	0	0	27	21	0	0	**49**
	Capacity (MW)	0.0	0.2	0.0	0.0	14.7	2.8	0.0	0.0	**17.7**
PY02	Count	0	2	0	1	81	38	0	0	**122**
	Capacity (MW)	0.0	0.8	0.0	1.4	51.3	5.7	0.0	0.0	**59.1**
PY03	Count	0	4	0	2	135	78	0	2	**221**
	Capacity (MW)	0.0	1.6	0.0	2.6	88.8	10.7	0.0	1.6	**105.2**
PY04	Count	0	7	0	3	184	108	0	2	**304**
	Capacity (MW)	0.0	3.8	0.0	4.0	113.3	16.3	0.0	1.6	**139.1**
PY05	Count	0	13	0	5	215	122	0	2	**357**
	Capacity (MW)	0.0	7.5	0.0	13.0	135.7	19.5	0.0	1.6	**177.3**
PY06	Count	0	20	0	8	232	135	0	2	**397**
	Capacity (MW)	0.0	12.6	0.0	25.7	146.9	23.6	0.0	1.6	**210.5**
PY07	Count	0	22	1	9	256	142	0	4	**434**
	Capacity (MW)	0.0	13.4	0.4	30.1	156.5	25.6	0.0	2.9	**228.9**
PY08	Count	0	28	1	9	256	142	0	5	**441**
	Capacity (MW)	0.0	14.0	0.4	30.1	156.5	25.6	0.0	3.1	**229.8**
PY09	Count	1	46	9	9	256	142	0	8	**471**
	Capacity (MW)	1.0	21.3	3.1	30.1	156.5	25.6	0.0	4.7	**242.3**
PY10	Count	2	110	89	9	256	142	0	15	**623**
	Capacity (MW)	1.6	33.7	40.7	30.1	156.5	25.6	0.0	13.3	**301.5**
PY11	Count	17	113	108	9	257	143	0	20	**667**
	Capacity (MW)	1.8	34.5	52.9	30.1	157.1	26.4	0.0	23.7	**326.6**
PY12	Count	164	119	147	11	272	150	2	23	**888**

Program Year / Cumulative Project Count and Rebated Capacity		Advanced Energy Storage	Fuel Cell - CHP	Fuel Cell - Electric Only	Gas Turbine	Internal Combustion Engine	Microturbine	Pressure Reduction Turbine	Wind	All Projects
	Capacity (MW)	8.1	35.0	70.2	44.3	177.3	31.4	1.1	27.3	**394.7**
PY13	Count	214	121	175	11	274	150	2	25	**972**
	Capacity (MW)	13.3	37.0	88.4	44.3	177.7	31.4	1.1	28.3	**421.6**
PY14	Count	339	121	214	11	276	150	2	25	**1138**
	Capacity (MW)	21.1	37.0	97.4	44.3	178.0	31.4	1.1	28.3	**438.6**
PY15	Count	343	121	215	11	277	150	2	25	**1144**
	Capacity (MW)	21.3	37.0	98.5	44.3	178.3	31.4	1.1	28.3	**440.2**

Table A 13 lists incentives, total eligible costs, and leverage ratios by program year and technology type.

Table A-13: Incentives, Costs, and Leverage Ratio by Program Year and Technology Type

Program Year / Incentive, Cost, and Leverage (MM Nominal $)		Advanced Energy Storage	Fuel Cell - CHP	Fuel Cell - Electric Only	Gas Turbine	Internal Combustion Engine	Microturbine	Pressure Reduction Turbine	Wind	All Projects
PY01	Incentive	0.00	0.50	0.00	0.00	9.04	2.22	0.00	0.00	11.76
	Cost	0.00	3.60	0.00	0.00	30.71	8.14	0.00	0.00	42.45
	Leverage	N/A	6.20	N/A	N/A	2.40	2.67	N/A	N/A	2.61
PY02	Incentive	0.00	1.50	0.00	0.81	20.67	2.33	0.00	0.00	25.31
	Cost	0.00	4.26	0.00	3.73	81.12	8.41	0.00	0.00	97.53
	Leverage	N/A	1.84	N/A	3.61	2.92	2.61	N/A	N/A	2.85
PY03	Incentive	0.00	3.38	0.00	1.00	21.54	4.78	0.00	2.63	33.33
	Cost	0.00	7.28	0.00	4.69	81.33	17.41	0.00	5.38	116.09
	Leverage	N/A	1.16	N/A	3.69	2.78	2.64	N/A	1.04	2.48
PY04	Incentive	0.00	5.58	0.00	1.00	16.86	5.07	0.00	0.00	28.51
	Cost	0.00	16.97	0.00	7.18	61.53	17.50	0.00	0.00	103.19
	Leverage	N/A	2.04	N/A	6.18	2.65	2.45	N/A	N/A	2.62
PY05	Incentive	0.00	7.89	0.00	1.05	12.13	2.85	0.00	0.00	23.92
	Cost	0.00	22.46	0.00	13.30	53.58	11.62	0.00	0.00	100.96
	Leverage	N/A	1.85	N/A	11.64	3.42	3.08	N/A	N/A	3.22
PY06	Incentive	0.00	19.46	0.00	1.80	6.96	3.28	0.00	0.00	31.50
	Cost	0.00	37.43	0.00	29.57	29.78	14.08	0.00	0.00	110.86
	Leverage	N/A	0.92	N/A	15.43	3.28	3.29	N/A	N/A	2.52
PY07	Incentive	0.00	2.00	1.00	0.60	6.61	2.02	0.00	1.84	14.07
	Cost	0.00	4.47	3.85	1.38	34.30	7.88	0.00	6.35	58.24
	Leverage	N/A	1.24	2.85	1.30	4.19	2.90	N/A	2.46	3.14

Program Year / Incentive, Cost, and Leverage (MM Nominal $)		Advanced Energy Storage	Fuel Cell - CHP	Fuel Cell - Electric Only	Gas Turbine	Internal Combustion Engine	Microturbine	Pressure Reduction Turbine	Wind	All Projects
PY08	Incentive	0.00	2.78	0.00	0.00	0.00	0.00	0.00	0.26	3.03
	Cost	0.00	5.98	0.00	0.00	0.00	0.00	0.00	0.35	6.33
	Leverage	N/A	1.16	N/A	N/A	N/A	N/A	N/A	0.34	1.09
PY09	Incentive	2.00	23.54	11.50	0.00	0.00	0.00	0.00	2.41	39.45
	Cost	6.49	62.49	30.51	0.00	0.00	0.00	0.00	5.14	104.62
	Leverage	2.25	1.65	1.65	N/A	N/A	N/A	N/A	1.14	1.65
PY10	Incentive	1.20	40.02	159.16	0.00	0.00	0.00	0.00	12.08	212.47
	Cost	5.17	90.73	387.27	0.00	0.00	0.00	0.00	33.46	516.62
	Leverage	3.30	1.27	1.43	N/A	N/A	N/A	N/A	1.77	1.43
PY11	Incentive	0.52	1.81	33.57	0.00	1.63	0.44	0.00	9.47	47.44
	Cost	0.88	7.18	153.22	0.00	2.55	2.83	0.00	40.36	207.02
	Leverage	0.69	2.96	3.56	N/A	0.57	5.50	N/A	3.26	3.36
PY12	Incentive	12.66	1.11	46.30	2.11	29.35	4.42	1.31	3.75	101.02
	Cost	22.33	5.26	204.06	59.32	78.90	29.14	4.70	17.07	420.77
	Leverage	0.76	3.72	3.41	27.09	1.69	5.59	2.58	3.55	3.17
PY13	Incentive	9.23	3.86	43.58	0.00	0.21	0.00	0.00	1.44	58.31
	Cost	17.01	17.12	225.28	0.00	1.80	0.00	0.00	5.57	266.77
	Leverage	0.84	3.44	4.17	N/A	7.70	N/A	N/A	2.87	3.16
PY14	Incentive	11.65	0.00	19.78	0.00	0.46	0.00	0.00	0.00	31.88
	Cost	25.29	0.00	102.09	0.00	5.17	0.00	0.00	0.00	132.55
	Leverage	1.17	N/A	4.16	N/A	10.34	N/A	N/A	N/A	3.16
PY15	Incentive	0.38	0.00	2.03	0.00	0.56	0.00	0.00	0.00	2.98
	Cost	0.69	0.00	12.31	0.00	4.41	0.00	0.00	0.00	17.40

Program Year / Incentive, Cost, and Leverage (MM Nominal $)		Advanced Energy Storage	Fuel Cell - CHP	Fuel Cell - Electric Only	Gas Turbine	Internal Combustio n Engine	Microturbin e	Pressure Reduction Turbine	Wind	All Projects
	Leverage	0.79	N/A	5.06	N/A	6.81	N/A	N/A	N/A	4.85
Total	***Incentive***	***37.65***	***113.43***	***317.55***	***8.37***	***126.01***	***27.41***	***1.31***	***33.88***	***665.61***
	Cost	***77.85***	***285.22***	***1121.41***	***119.17***	***465.18***	***117.02***	***4.70***	***113.67***	***2304.22***
	Leverage	***1.07***	***1.51***	***2.53***	***13.23***	***2.69***	***3.27***	***2.58***	***2.35***	***2.46***

Appendix B

APPENDIX B ENERGY IMPACTS ESTIMATION METHODOLOGY AND RESULTS

This appendix provides additional detail about the metered data and the ratio estimation methodology used to quantify the energy impacts of the Self-Generation Incentive Program (SGIP) in this evaluation report. This appendix also includes energy and peak demand impacts detail not shown in Section 5.

- Estimation Methodology
    - Data Processing and Validation
    - Operations Status Survey
    - Ratio Estimation
- Energy Impacts
- Coincident Demand Impacts

B.1 Estimation Methodology

Estimation of energy impacts relies on large data sets of metered actual electrical generation, fuel consumption and heat recovery. We use these data to estimate electrical generation, fuel consumption and heat recovery where we have no metered data that passes quality control validation. We multiply sums of metered impacts taken for a particular type of system over a particular period by of time by the ratio of sums of capacities without valid data to those with valid metered data. The impact estimate then is the sum of the metered and the estimated impact.

Data Processing and Validation

Descriptions of the metered electricity generation, fuel consumption, and useful heat recovery data that are the basis of this impacts evaluation are presented below

Electric Net Generation Output (NGO) Data

Metered electric NGO data provide information on the amount of electricity generated by SGIP projects net of ancillary loads such as pumps and compressors. These data are typically kWh recorded at 15-minute intervals but sometimes are at hourly or longer intervals or are average kW over the interval.

Electric NGO data are collected from a variety of sources, including meters installed by Itron and its subcontractors under the direction of the PAs, and meters installed by project hosts, applicants, electric utilities, and third parties. Because many different meters are in use among the many different providers, these electric NGO data arrive in a wide variety of data formats. Some formats require extensive processing to be associated with the correct project and put into a format common to all projects.

During processing to the common format, all electric NGO data pass through a rigorous quality control review. Only data that pass the review are accepted for use in this evaluation. Key factors in the review are system capacity, unit count, and technology. Some technologies can generate farther above nameplate capacity for longer periods than other technologies. Some technologies can generate at lower capacity factor for longer periods than other technologies. In addition, some fuel cells may consume substantial electricity during standby.

Fuel Consumption Data

Fuel consumption data are used in this impacts evaluation to determine system efficiencies and to estimate greenhouse gas (GHG) emission impacts. To date, fuel consumption data collection activities have focused exclusively on consumption of natural gas by SGIP projects. In the future, it may also be necessary to monitor consumption of gaseous renewable fuel (i.e., biogas) to more accurately assess the impacts of SGIP projects using blends of renewable and non-renewable fuels.

Fuel consumption data used in this impacts evaluation are obtained mostly in units of standard cubic feet or therms from natural gas metering systems installed on SGIP projects by natural gas distribution companies, SGIP participants, or by third parties. Itron reviews fuel consumption data and documents their bases prior to processing the data into a common data format and unit of kBtu LHV.

During processing of fuel consumption data, they are merged with electric NGO data for quality control reviews. The fuel data are examined for reasonableness of electrical conversion efficiency for the technology over the course of multiple hours or days. In cases where validity checks fail, data providers are contacted to further refine the basis of data, otherwise data are ignored as unrepresentative. In some cases, it is determined the data are for a host customer's entire facility rather than from metering dedicated to the SGIP project.

Some fuel consumption data arrive already merged with NGO data but most fuel consumption data arrive in various formats and intervals much greater than one hour (e.g., in daily or monthly intervals). These longer interval data enable calculation of monthly and annual efficiencies but are not used to estimate performance for shorter intervals.

Useful Heat Recovery Data

Useful heat recovery is the thermal energy captured by heat recovery equipment and used to satisfy heating and/or cooling loads at the SGIP project site. Useful heat recovery data are used to assess overall efficiencies of SGIP projects and to estimate avoided baseline natural gas use. This avoided use is used in calculation of GHG emission impact estimates where it reduces net emissions.

Heat recovery data are collected from metering systems installed by Itron as well as metering systems installed by applicants, hosts, and third parties. Because many different meters are in use among the many different providers, these heat data arrive in a wide variety of data formats. Some formats require extensive processing to be associated with the correct project and put into a format common to all projects. Heat data may arrive in units of Btu or as flow with associated high and low temperatures. In the latter case, heat exchanger and fluid properties are identified in calculation of useful recovered kBtu.

Over the course of the SGIP, the approach for collecting useful heat recovery data has changed. Useful heat recovery data collection historically has involved installation of invasive monitoring equipment (i.e., insertion-type flow meters). Many third parties had this type of equipment installed at the time the SGIP project was commissioned, either as part of their contractual agreement with a third-party vendor or as part of an internal process/energy monitoring plan. In numerous cases, Itron obtains useful heat recovery data metered by others in an effort to minimize both the cost and disruption of installing useful heat recovery monitoring equipment. The majority of useful heat recovery data for years 2003 and 2004 were obtained in this manner.

Itron began installing useful heat recovery metering in the summer of 2003 for SGIP projects that were included in the sample design but for which data were not available. As the useful heat recovery data collection effort grew, it became clear that we could no longer rely on data from third party or host customer metering. In numerous instances, agreements and plans concerning these data did not yield valid data for analysis. Uninterrupted collection and validation of useful heat recovery data was labor-intensive and required examination of the data by more expert staff, thereby increasing costs. In addition, reliance on useful heat recovery data collected by SGIP host customers and third parties created evaluation schedule impacts and other risks that more than outweighed the benefits of not having to install new metering.

In mid-2006, Itron responded to the useful heat recovery data issues by changing the approach to collection of useful heat recovery data. We continued to collect useful heat recovery data from program participants in those instances where valid data could be obtained easily and reliably. For all other projects selected for metered data collection, we installed useful heat recovery metering systems ourselves. These systems utilized non-invasive components such as ultrasonic flow meters, clamp-on temperature sensors, and wireless, cellular-based communications to reduce the time and disruption of the installations and to increase data communication reliability. The increase in equipment costs was offset by the decrease in installation time and a decrease in maintenance problems.

Operations Status Survey

Using a short phone survey, we collected categorical operating status data on systems for which no metered data are available and that are not already known to be permanently retired. Completed surveys allow classification of system-months as offline or online. For offline system-months, we estimated impacts using a zero ratio estimator. For online system months, we estimated impacts using a ratio estimator developed from similar systems whose metered data indicate they were online that same month. Some surveys identify systems as being permanently retired. We identify a best estimate of retirement date in the survey and estimate impacts from that date forward using a zero ratio estimator.

Operating status surveys are conducted only with contacts familiar with the operational status of the unmetered system. The operating status survey identifies most recently known system contacts that may include system, hosts, applicants, or former data providers. Contact information from PA system lists, inspection reports, or site visit summaries are used. When these contacts are out of date, contact information may be sought from internet sources.

Ratio Estimation

Non-AES Project Approach

An overview of the ratio estimation methodology was included in Section 4. The strata included in the ratio analysis for electricity generation values were presented in Table 4-1, and are also listed below:

1. Technology type
2. Operational status

3. Program incentive structure (pre-SB 412 and post-SB 412)
4. Warranty status (under corresponding handbook)
5. Fuel type
6. Capacity size category
7. PA

The ratio estimation methodology works well when metered data are available in each stratum. In a limited number of cases, lack of metered data for certain strata necessitated use of more general strata. For these estimates the criteria of matching hours and/or project characteristics is relaxed. The relaxation begins with inclusion of other hours, daytime or night, from the same date. If fewer than five projects have metered data during those hours, the relaxation continues to any hours on the same date. If still fewer than five projects have metered data during that date, the hours are allowed to include the same hour in similar days, weekend or weekday, of the same week. The hours included continue to expand ultimately to include the entire month. If still fewer than five projects have metered data in that month, systems with a different PA are allowed and the hours then are contracted to the same hour on weekends or weekdays in that month. The cycle of expansion of allowed hours then repeats. All estimates include the same technology type and warranty status.

AES Projects Sample to Population Scaling Methodology

To scale sample data results up to the population level, the following calculation was performed to determine the weight of each individual system within the sample.

$$w_i^a = C_i^a \cdot \frac{\sum_{j=1}^{Na} C_j^a}{\sum_{k=1}^{na} C_k^a}$$

Where:

wia = weight of system 'i' in sample with technology type 'a'

Cxa = capacity (in Kw) of system 'x' with technology type 'a'

Na = number of systems in population with technology type 'a'

na = number of systems in sample with technology type 'a'

In English, we multiply the capacity of the system we are weighing by the total size (in kW) of all systems within the population with the same technology type, and divide by the total size (in kW) of all systems within the sample of the same technology type. This is known as kW weighting.

The population mean was then estimated as:

$$\bar{X} = \frac{\sum_{i=1}^{n} w_i x_i}{\sum_{i=1}^{n} w_i}$$

With standard deviation:

$$\sigma = \sqrt{\frac{\sum_{i=1}^{n} w_i (x_i - \bar{X})^2}{\sum_{i=1}^{n} w_i}}$$

Where:

x_i = NCP (noncoincident peak demand) for system 'i'

w_i = weight of system 'i'

n = number of systems in sample

B.2 Energy Impacts

The following tables summarize program energy impacts for 2014 and 2015. Some tables include earlier years to demonstrate trends over time.

Table B-1 and Table B-2 list 2014 and 2015 annual electrical energy impact and associated annual capacity factor by technology type.

Table B-1: 2014 Annual Electric Generation and Capacity Factor by Technology Type

Technology Type	Annual Electricity Generated (GWh)	Annual Capacity Factor
Fuel Cell - CHP	142.6	47.3%
Fuel Cell - Electric Only	400.4	70.7%
Gas Turbine	199.1	75.4%
Internal Combustion Engine	287.6	20.6%
Microturbine	55.0	23.1%
Pressure Reduction Turbine	3.02	69.0%
Wind	49.9	23.8%
Total	**1,138**	

Table B-2: 2015 Annual Electric Generation and Capacity Factor by Technology Type

Technology Type	Annual Electricity Generated (GWh)	Annual Capacity Factor
Fuel Cell - CHP	119.0	37.5%
Fuel Cell - Electric Only	524.4	69.9%
Gas Turbine	251.8	75.6%
Internal Combustion Engine	310.4	21.1%
Microturbine	68.5	25.3%
Pressure Reduction Turbine	4.86	60.8%
Wind	50.5	20.4%
Total	**1,329**	

Table B-3 and Table B-4 list 2014 and 2015 annual electrical energy impact and annual capacity factor by technology and fuel category.

Table B-3: 2014 Annual Electric Generation and Capacity Factor by Technology Type and Energy Source

Technology Type	Energy Source	Annual Electricity Generated (GWH)	Annual Capacity Factor
Fuel Cell – CHP	Non-Renewable	60.9	42.4%
	Renewable	81.8	51.8%
Fuel Cell – Electric Only	Non-Renewable	243.0	69.4%
	Renewable	157.4	72.8%
Gas Turbine	Non-Renewable	199.1	75.4%
Internal Combustion Engine	Non-Renewable	243.2	19.4%
	Renewable	44.4	31.1%
Microturbine	Non-Renewable	49.0	25.4%
	Renewable	6.0	13.1%
Pressure Reduction Turbine	Renewable	3.0	69.0%
Wind	Non-Renewable	49.9	23.8%
	Total	**1,138**	

Table B-4: 2015 Annual Electric Generation and Capacity Factor by by Technology Type and Energy Source

Technology Type	Energy Source	Annual Electricity Generated (GWH)	Annual Capacity Factor
Fuel Cell – CHP	Non-Renewable	51.6	32.4%
	Renewable	67.3	42.7%
Fuel Cell – Electric Only	Non-Renewable	385.9	72.2%
	Renewable	138.6	64.1%
Gas Turbine	Non-Renewable	251.8	75.6%
Internal Combustion Engine	Non-Renewable	240.6	18.8%
	Renewable	69.8	36.3%
Microturbine	Non-Renewable	62.8	28.2%
	Renewable	5.7	12.0%
Pressure Reduction Turbine	Renewable	4.9	60.8%
Wind	Non-Renewable	50.5	20.4%
	Total	**1,329**	

Table B-5 lists 2014 annual electrical energy generation by Program Administrator, technology type, and fuel category.

Table B-5: 2014 Annual Electric Generation by Technology Type and Energy Source and Program Administrator

Technology Type / Energy Source		Electric Energy Impact (GWh)				
		Program Administrator				
		CSE	PG&E	SCE	SCG	Total
Fuel Cell – CHP	Non-Renewable	3.1	28.8	7.9	21.1	60.9
	Renewable	35.5	10.1	20.2	16.0	81.8
	All	***38.5***	***38.9***	***28.1***	***37.1***	***142.6***
Fuel Cell – Electric Only	Non-Renewable	20.8	113.5	58.2	50.4	243.0
	Renewable	11.4	79.7	40.3	25.9	157.4
	All	***32.2***	***193.3***	***98.5***	***76.4***	***400.4***
Gas Turbine	Non-Renewable	64.0	10.5	-	124.6	199.1
	All	***64.0***	***10.5***	***-***	***124.6***	***199.1***
Internal Combustion Engine	Non-Renewable	2.2	105.3	43.3	92.5	243.2
	Renewable	4.1	18.8	12.9	8.6	44.4
	All	***6.3***	***124.1***	***56.2***	***101.0***	***287.6***
Microturbine	Non-Renewable	0.9	30.4	4.2	13.5	49.0
	Renewable	0.7	3.7	1.6	-	6.0
	All	***1.6***	***34.0***	***5.8***	***13.5***	***55.0***
Pressure Reduction Turbine	Renewable	3.0	-	-	-	3.0
	All	***3.0***	***-***	***-***	***-***	***3.0***
Wind	Renewable	0.9	15.7	33.2	-	49.9
	All	***0.9***	***15.7***	***33.2***	***-***	***49.9***
Non-Renewable		90.9	288.6	113.6	302.1	***795.2***
Renewable		55.6	128.0	108.2	50.6	***342.4***
Grand Total		***146.5***	***416.5***	***221.9***	***352.7***	***1,137.6***

Table B-6: 2015 Annual Electric Generation by Technology Type, Energy Source, and Program Administrator

Technology Type / Energy Source		Electric Energy Impact (GWh)				
		Program Administrator				Total
		CSE	PG&E	SCE	SCG	
Fuel Cell – CHP	Non-Renewable	2.4	27.5	7.0	14.7	51.6
	Renewable	34.1	7.8	14.9	10.5	67.3
	All	***36.5***	***35.4***	***21.9***	***25.2***	***119.0***
Fuel Cell – Electric Only	Non-Renewable	26.4	191.7	90.4	77.3	385.9
	Renewable	8.1	78.3	32.5	19.7	138.6
	All	***34.5***	***270.0***	***123.0***	***97.0***	***524.4***
Gas Turbine	Non-Renewable	95.7	47.6	-	108.5	251.8
	All	***95.7***	***47.6***	***-***	***108.5***	***251.8***
Internal Combustion Engine	Non-Renewable	1.8	97.1	51.3	90.3	240.6
	Renewable	4.1	36.0	20.5	9.1	69.8
	All	***6.0***	***133.1***	***71.8***	***99.4***	***310.4***
Microturbine	Non-Renewable	0.3	39.4	7.0	16.2	62.8
	Renewable	0.7	2.7	2.3	-	5.7
	All	***0.9***	***42.1***	***9.3***	***16.2***	***68.5***
Pressure Reduction Turbine	Renewable	2.9	1.9	-	-	4.9
	All	***2.9***	***1.9***	***-***	***-***	***4.9***
Wind	Renewable	3.9	21.9	24.7	-	50.5
	All	***3.9***	***21.9***	***24.7***	***-***	***50.5***
Non-Renewable		126.6	403.4	155.7	307.1	***992.7***
Renewable		53.8	148.7	94.9	39.3	***336.7***
Grand Total		***180.4***	***552.1***	***250.6***	***346.4***	***1,329.5***

B.3 Demand Impacts

Plots of IOU peak hour generation from 2003 to 2015 follow for PG&E, SCE and SDG&E. Totals and subtotals by system categories SB 412 PR/POST, fuel category, and technology appear from Figure B-1 to Figure B-12.

Figure B-1: PG&E Peak Hour Generation by Calendar Year

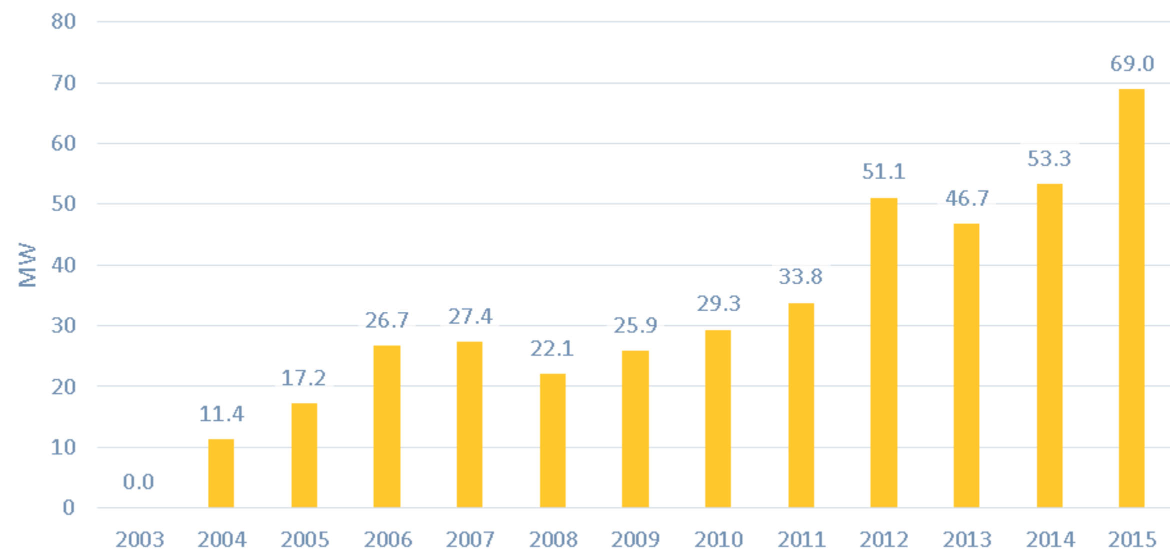


Figure B-2: PG&E Peak Hour Generation by SB 412 PRE/POST

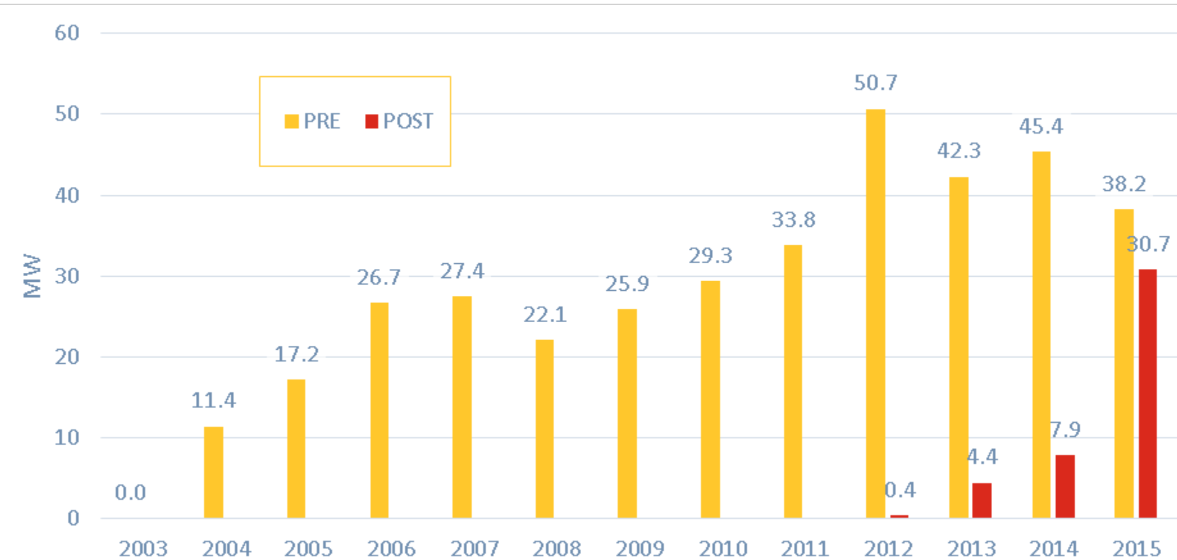


Figure B-3: PG&E Peak Hour Generation by Fuel

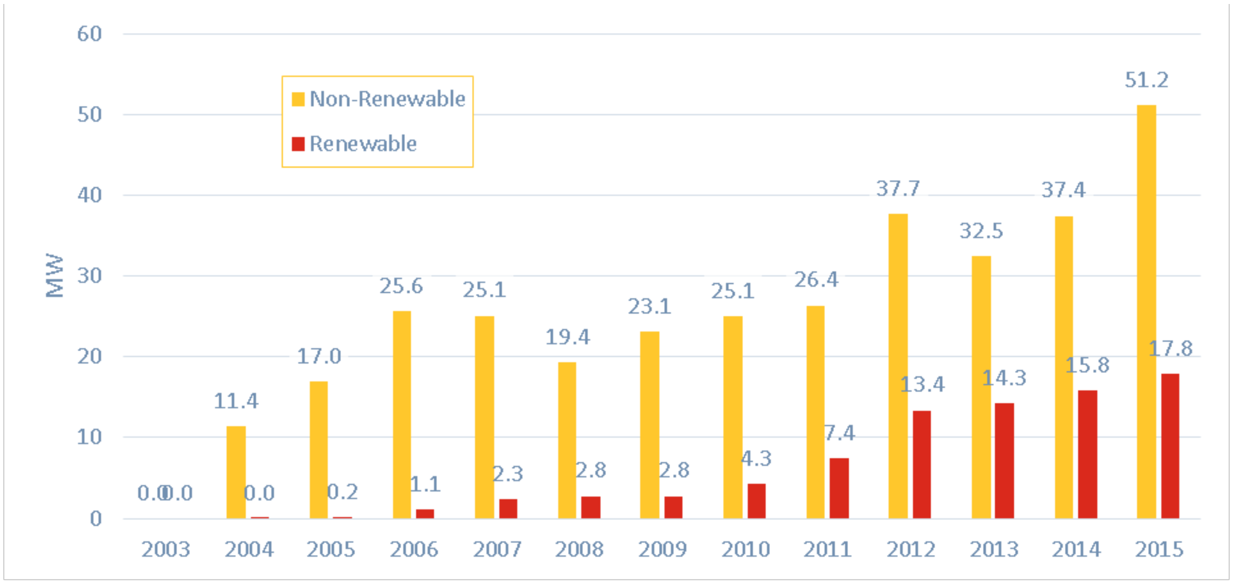


Figure B-4: PG&E Peak Hour Generation by Technology

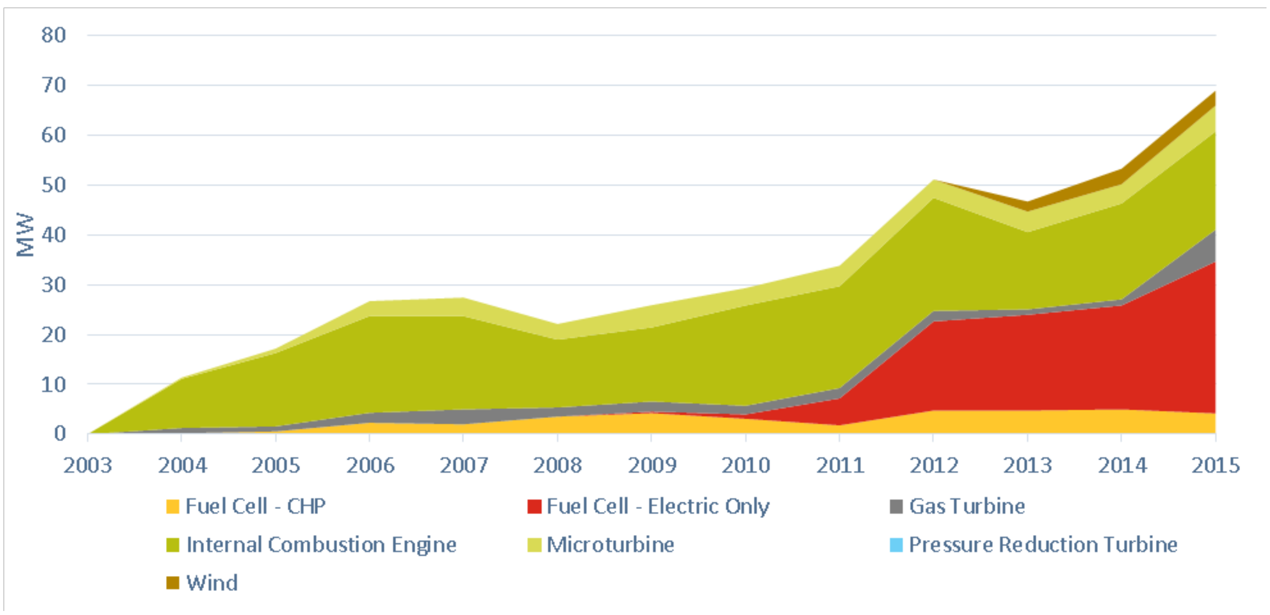


Figure B-5: SCE Peak Hour Generation by Calendar Year

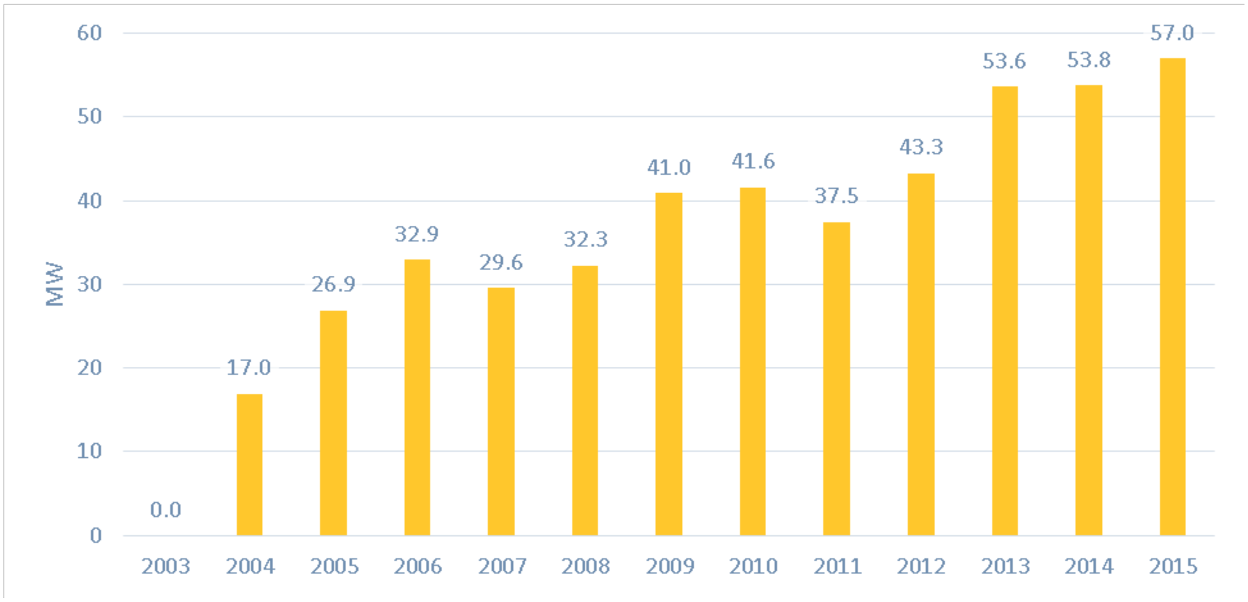


Figure B-6: SCE Peak Hour Generation by SB 412 PRE/POST

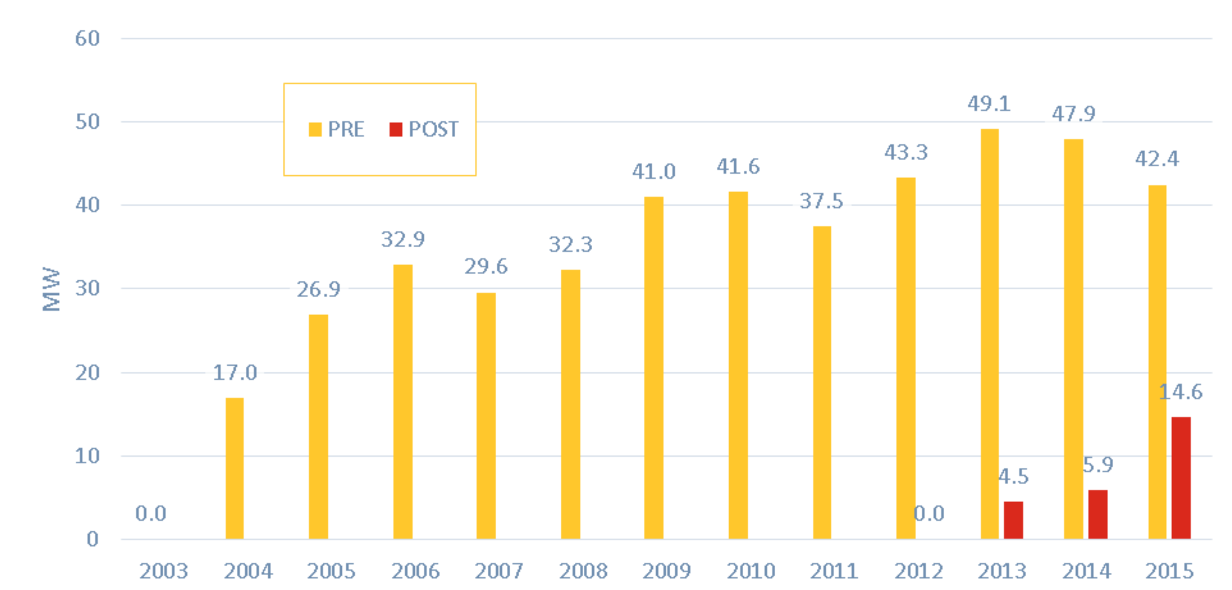


Figure B-7: SCE Peak Hour Generation by Fuel

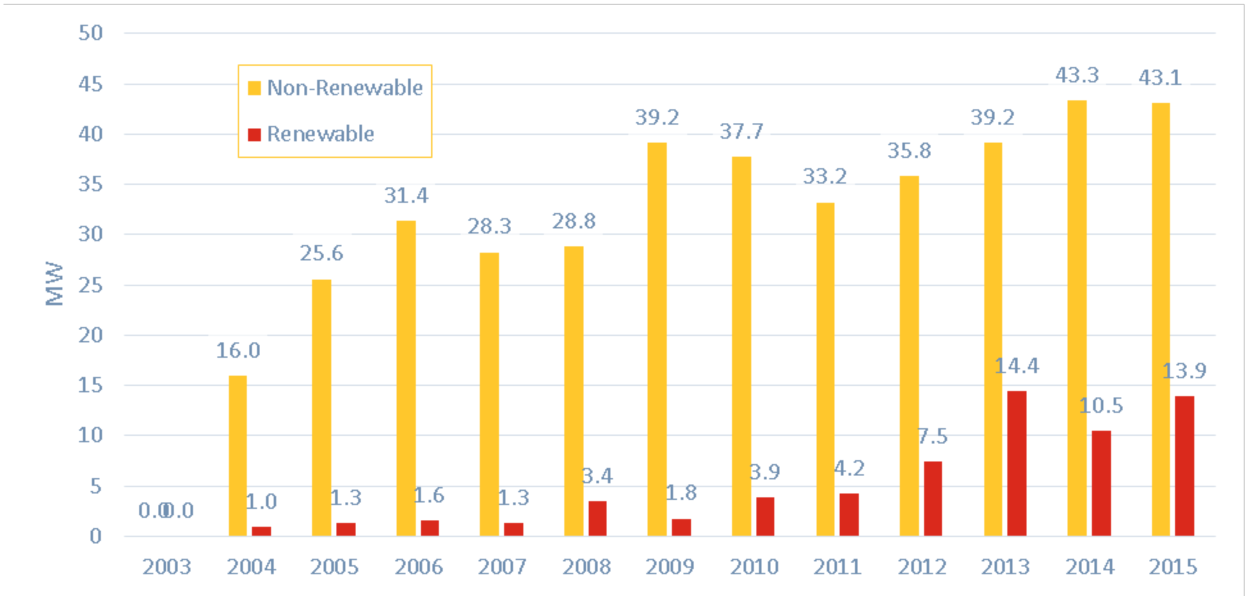


Figure B-8: SCE Peak Hour Generation by Technology

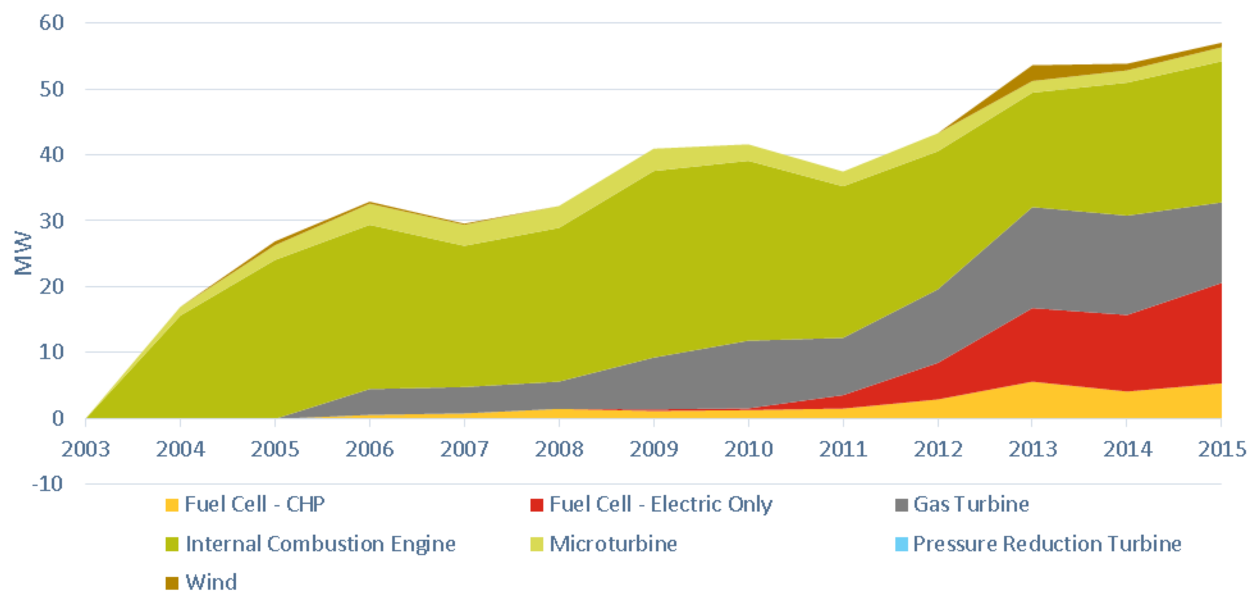


Figure B-9: SDG&E Peak Hour Generation by Calendar Year

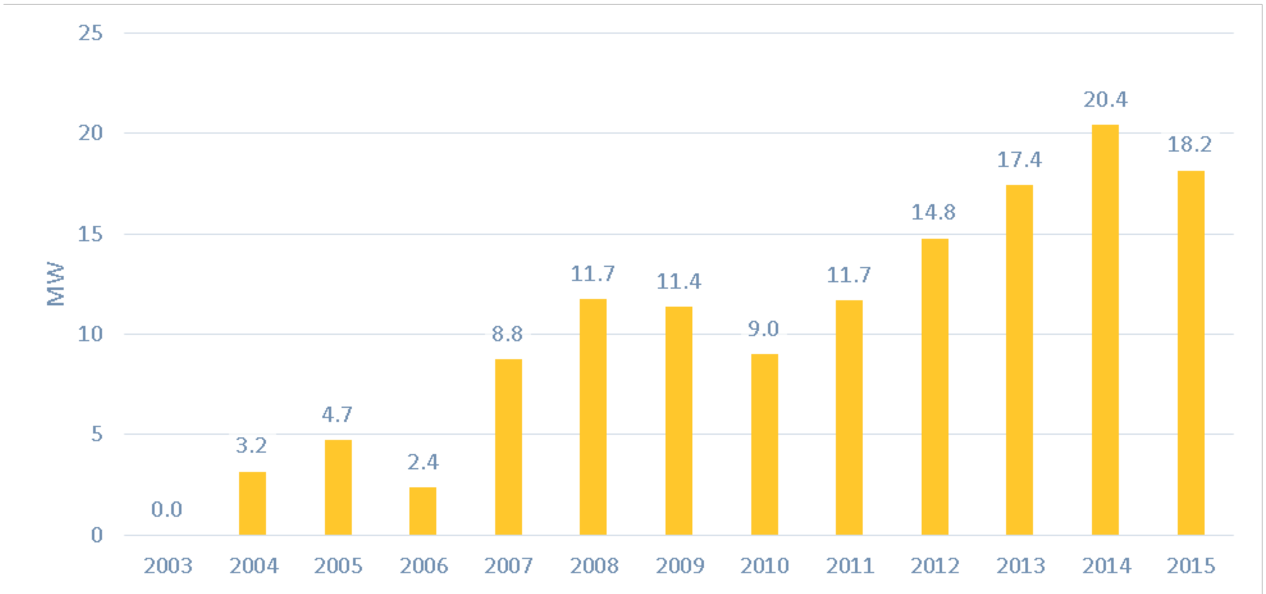


Figure B-10: SDG&E Peak Hour Generation by SB 412 PRE/POST

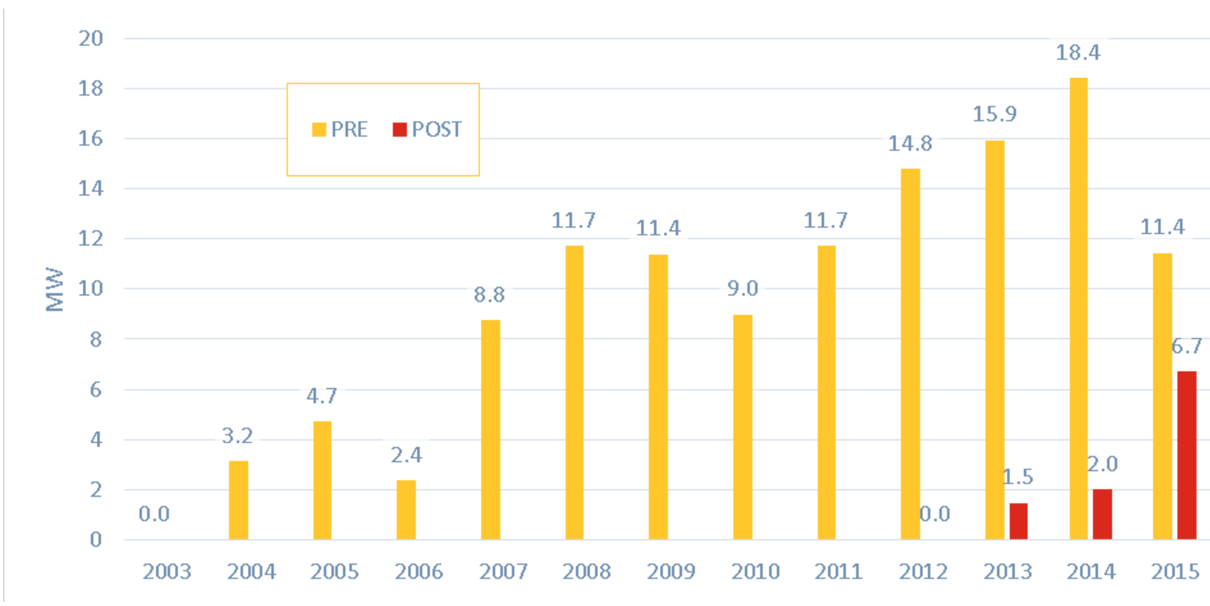


Figure B-11: SDG&E Peak Hour Generation by Fuel

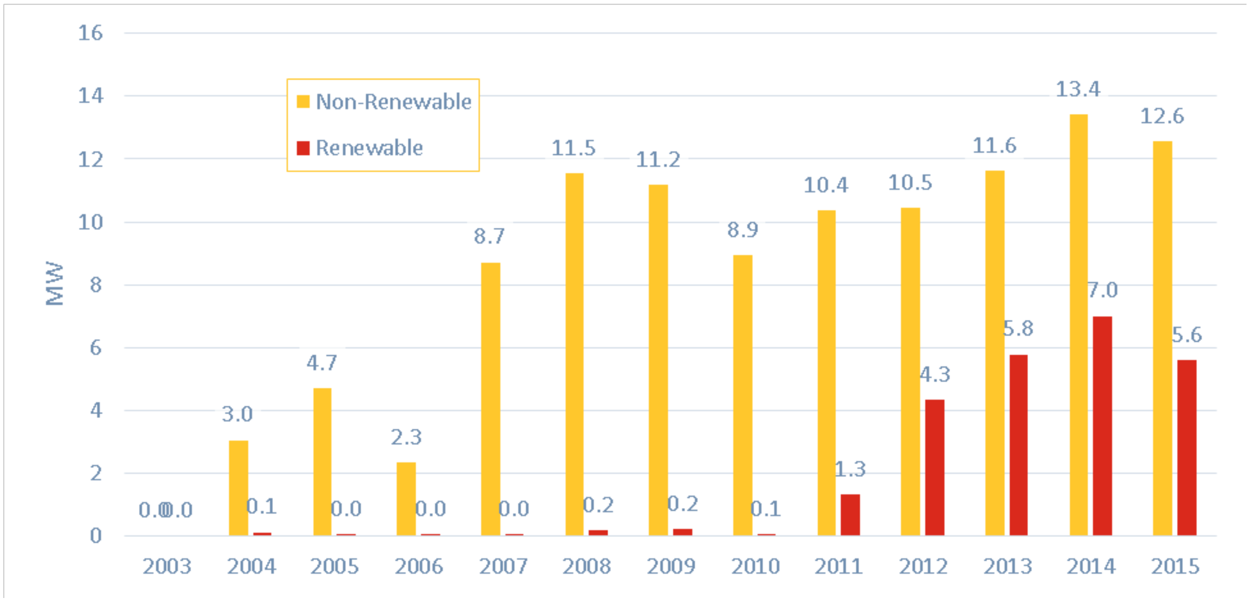


Figure B-12: SDG&E Peak Hour Generation by Technology

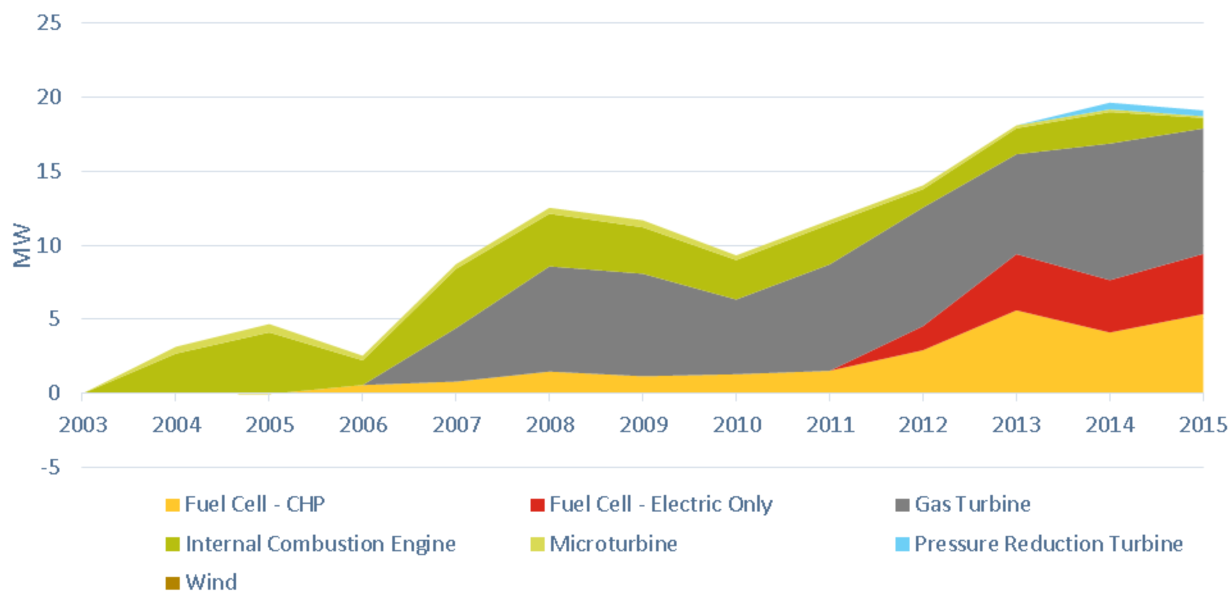


Figure B-13 and Figure B-14 show for 2014 and 2015 respectively the total program generation coincident with the CAISO and IOU peak hours alongside average program generation coincident with the top 200 peak hours.

» Peak hour and top 200 average generation were within 90% of each other in 2015 for CAISO and IOUs

» Peak hour generation overstates average of top 200 hours for PG&E and SCE in 2015

Figure B-13: 2014 CAISO and IOU Peak and Top 200 Peak Hour Generation

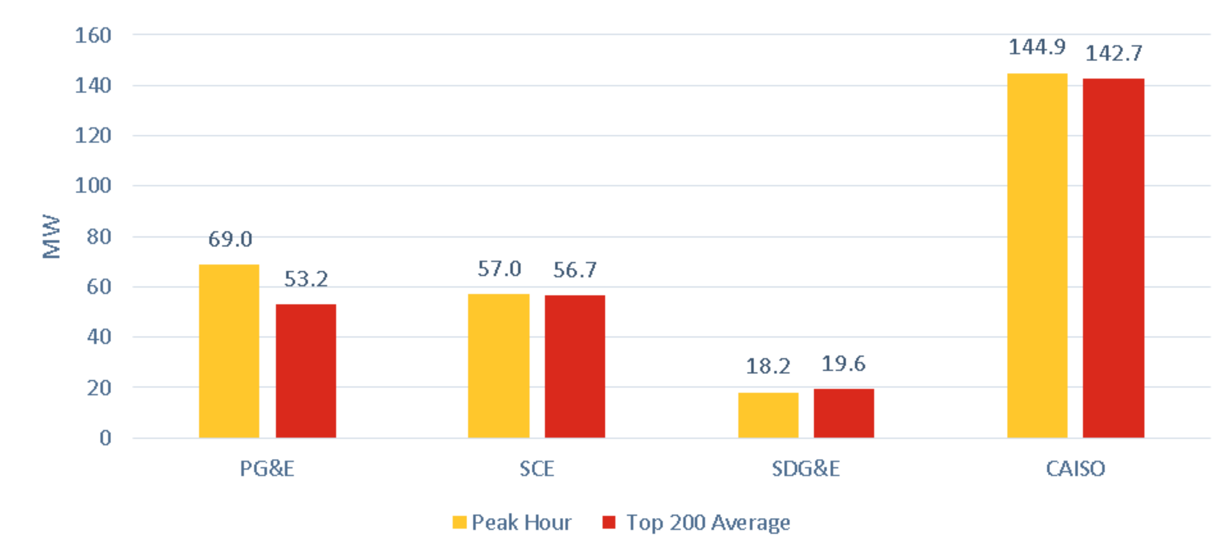
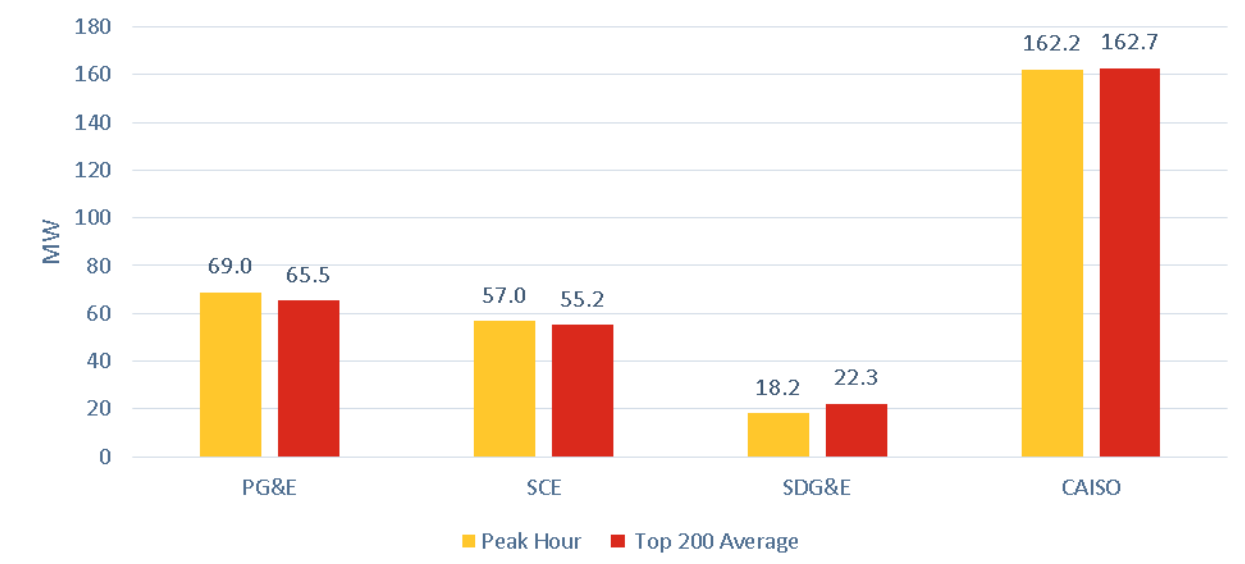
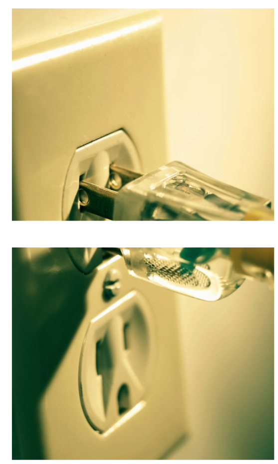


Figure B-14: 2015 CAISO and IOU Peak and Top 200 Peak Hour Generation



Appendix C



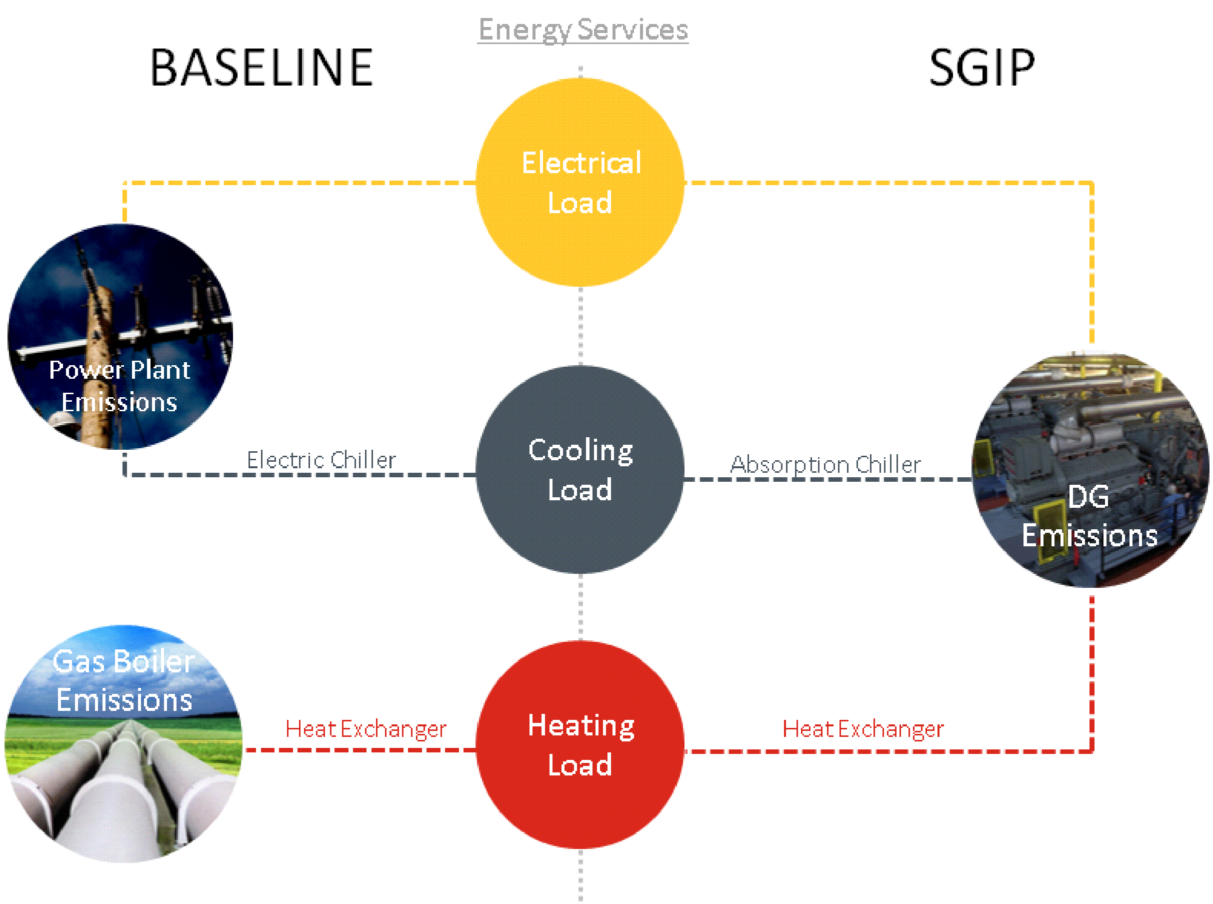
APPENDIX C GREENHOUSE GAS IMPACTS ESTIMATION METHODOLOGY AND RESULTS

This appendix describes the methodology used to estimate the impacts on greenhouse gas (GHG) emissions from the operation of Self-Generation Incentive Program (SGIP) projects. The GHGs considered in this analysis are limited to carbon dioxide (CO_2) and methane (CH_4), as these are the two primary pollutants that are potentially affected by the operation of SGIP projects.

C.1 Overview

Figure C-1 shows each component of the GHG impacts calculation and is described below along with the variable name used in equations presented later.

Figure C-1: Greenhouse Gas Impacts Summary Schematic



Hourly GHG impacts are calculated for each SGIP project as the difference between the GHG emissions produced by the rebated distributed generation (DG) project and baseline GHG emissions. Baseline GHG emissions are those that would have occurred in the absence of the SGIP project. SGIP projects displace baseline GHG emissions by satisfying site electric loads as well as heating/cooling loads, in some cases.

SGIP projects powered by biogas may reduce emissions of CH_4 in cases where venting of the biogas directly to the atmosphere would have occurred in the absence of the SGIP project.

SGIP Project CO_2 Emissions (sgipGHG)

The operation of renewable and non-renewable fueled DG projects (excluding wind and PRT) emits CO_2 as a result of combustion/conversion of the fuel powering the project. Hour-by-hour emissions of CO_2 from SGIP projects are estimated based on their electricity generation and fuel consumption throughout the year.

Electric Power Plant CO_2 Emissions (basePpEngo)

When in operation, power generated by all SGIP projects directly displaces electricity that in the absence of the SGIP would have been generated by a central station power plant to satisfy the site's electrical loads.[1] As a result, SGIP projects displace the accompanying CO_2 emissions that these central station power plants would have released to the atmosphere. The avoided CO_2 emissions for these baseline conventional power plants are estimated on an hour-by-hour basis over all 8,760 hours of the year.[2] The estimates of electric power plant CO_2 emissions are based on a methodology developed by Energy + Environmental Economics, Inc. (E3) and made publicly available on its website as part of its avoided cost calculator.[3]

CO_2 Emissions Associated with Cooling Services (basePpChiller)

SGIP projects delivering recovered heat to absorption chillers are assumed to reduce the need to operate on-site electric chillers using electricity purchased from the utility company. Baseline CO_2 emissions associated with electric chiller operations are calculated based on estimates of hourly chiller operations and on the electric power plant CO_2 emissions methodology described previously.

1 In this analysis, GHG emissions from SGIP projects are compared only to GHG emissions from utility power generation that could be subject to economic dispatch (i.e., central station natural gas-fired combined cycle facilities and simple cycle gas turbine peaking plants). It is assumed that operation of SGIP projects has no impact on electricity generated from utility facilities not subject to economic dispatch. Consequently, comparison of SGIP projects to nuclear or hydroelectric facilities is not made as neither of these technologies is subject to dispatch.

2 Consequently, during those hours when an SGIP project is idle, displacement of CO_2 emissions from central station power plants is equal to zero.

3 Energy + Environmental Economics, Inc. Methodology and Forecasting of Long Term Avoided Costs for the Evaluation of California Energy Efficiency Programs. For the California Public Utilities Commission. October 25, 2004. http://www.ethree.com/CPUC/E3_Avoided_Costs_Final.pdf

CO_2 Emissions Associat7ed with Heating Services (baseBlr)

Recovered useful heat may displace natural gas that would have been used in the absence of the SGIP to fuel boilers to satisfy site heating loads. This displaces accompanying CO_2 emissions from the boiler's combustion process.[4]

CO_2 Emissions from Biogas Treatment (baseBio)

Biogas-powered SGIP projects capture and use CH_4 that otherwise may have been emitted to the atmosphere (vented), or captured and burned, producing CO_2 (flared). A flaring baseline was assumed for all facilities except dairies. Flaring was assumed to have the same degree of combustion as SGIP prime movers.

GHG impacts expressed in terms of CO_2 equivalent (CO_2eq)[5] were calculated by date and time (hereafter referred to as "hour") as:

$$\Delta GHG_{i,h} = sgipGHG_{i,h} - (basePpEngo_{i,h} + basePpChiller_{i,h} + baseBlr_{i,h} + baseBio_{i,h})$$

Where:

» $\Delta GHG_{i,h}$ is the GHG impact for SGIP project *I* for hour *h*
  > Units: Metric Tons CO_2eq / hr

Negative GHG impacts (ΔGHG) indicate reduction in GHG emissions. Not all SGIP projects include all of the above variables. Inclusion is determined by the SGIP DG technology and fuel types and is discussed further in Sections C.2 and C.3. Section C.2 describes GHG emissions from SGIP projects (*sgipGHG*), as well as heating and cooling services associated with combined heat and power (CHP) projects. In Section C.3, baseline GHG emissions are described in detail.

C.2 SGIP Project GHG Emissions (sgipGHG)

SGIP projects that consume natural gas or renewable biogas emit CO_2. CO_2 emission rates for the SGIP projects that use gaseous fuel were calculated as:

$$(CO_2)_T = \left(\frac{3412\ Btu}{kWh}\right)\left(\frac{1}{EFF_T}\right)\left(\frac{1\ ft^3 CH_4}{935\ Btu}\right)\left(\frac{1\ lbmole\ of\ CH_4}{379\ ft^3}\right)\left(\frac{1\ lbmole\ of\ CO_2}{1\ lbmole\ of\ CH_4}\right)\left(\frac{44\ lbs\ of\ CO_2}{1\ lbmole\ of\ CO_2}\right)$$

Where:

» $(CO_2)_T$ is the CO_2 emission rate for technology T.
  > Units: lbs CO_2 / kWh

4 Since virtually all carbon in natural gas is converted to CO_2 during combustion, the amount of CH_4 released from incomplete combustion is considered insignificant and is not included in this baseline component.

5 Carbon dioxide equivalency describes, for a given mixture and amount of greenhouse gas, the amount of CO_2 that would have the same global warming potential (GWP), when measured over a specific time period (100 years). This approach must be used to accommodate cases where the assumed baseline is venting of CH_4 to the atmosphere directly.

- EFF_T is the electrical efficiency of technology T.
  - Value: Measured value, dependent on technology type (see Table C-1)
  - Units: Dimensionless fractional efficiency
  - Basis: Lower heating value (LHV) metered data collected from SGIP projects.

Table C-1: Electrical Efficiency by Technology Type Used for GHG Emissions Calculation

Technology Type (T)	2014 Electrical Efficiency (EFF_T)	2015 Electrical Efficiency (EFF_T)
Fuel Cell – Combined Heat and Power	0.397	0.379
Fuel Cell – Electric Only	0.502	0.519
Gas Turbine	0.372	0.326
Internal Combustion Engine	0.292	0.315
Microturbine	0.224	0.219

The technology-specific emissions rates were calculated to account for CO_2 emissions from SGIP projects. When multiplied by the electricity generated by these projects, the results represent hourly CO_2 emissions in pounds, which are then converted to metric tons, as shown in the equation below.

$$sgipGHG_{i,h} = \left((CO_2)_T \cdot engohr_{i,h}\right)\left(\frac{1\ metric\ ton\ of\ CO_2}{2{,}205\ lbs\ of\ CO_2}\right)$$

Where:

- $sgipGHG_{i,h}$ is the CO_2 emitted by SGIP project *i* during hour *h*.
  - Units: Metric ton / hr
- $engohr_{i,h}$ is the electrical output of SGIP project *i* during hour *h.*
  - Units: kWh
  - Basis: Metered data collected from SGIP projects net of any parasitic losses.

C.3 Baseline GHG Emissions

The following description of baseline operations covers three areas. The first is the GHG emissions from electric power plants that would have been required to operate more in the SGIP's absence. These emissions correspond to electricity that was generated by SGIP projects, as well as to electricity that would have been consumed by electric chillers to satisfy cooling loads discussed in the previous section. Second, the GHG emissions from natural gas boilers that would have operated more to satisfy heating load discussed in the previous section. Third, the GHG emissions corresponding to biogas that would otherwise have been flared (CO_2) or vented in to the atmosphere (CH_4).

Central Station Electric Power Plant GHG Emissions (basePpEngo & basePpChiller)

This section describes the methodology used to calculate CO_2 emissions from electric power plants that would have occurred to satisfy the electrical loads served by the SGIP project in the absence of the program. The methodology involves combining emission rates (in metric tons of CO_2 per kWh of electricity generated) that are service territory- and hour-specific with information about the quantity of electricity either generated by SGIP projects or displaced by absorption chillers operating on heat recovered from SGIP CHP projects.

The service territory of the SGIP project is considered in the development of emission rates by accounting for whether the site is located in Pacific Gas & Electric's (PG&E's) territory (northern California) or in Southern California Edison's (SCE's) or Center for Sustainable Energy's (CSE's) territory (southern California). Variations in climate and electricity market conditions have an effect on the demand for electricity. This in turn affects the emission rates used to estimate the avoided CO_2 release by central station power plants. Lastly, timing of electricity generation affects the emission rates because the mix of high and low efficiency plants differs throughout the day. The larger the proportion of low efficiency plants used to generate electricity, the greater the avoided CO_2 emission rate.

Electric Power Plant CO2 Emissions Rate

The approach used to formulate hourly CO_2 emission rates for this analysis is based on methodology developed by E3 and found in its avoided cost calculation workbook. The E3 avoided cost calculation workbook assumes:

- The emissions of CO_2 from a conventional power plant depend upon its heat rate, which in turn is dictated by the plant's efficiency, and
- The mix of high and low efficiency plants in operation is determined by the price and demand for electricity at that time.

The premise for hourly CO_2 emission rates calculated in E3's workbook is that the marginal power plant relies on natural gas to generate electricity. Variations in the price of natural gas reflect the market demand conditions for electricity. As demand for electricity increases, all else being equal, the price of electricity will rise. To meet the higher demand for electricity, utilities will have to rely more heavily on less efficient power plants once production capacity is reached at their relatively efficient plants. This means that during periods of higher electricity demand, there is increased reliance on lower efficiency plants, which in turn leads to a higher emission rate for CO_2. In other words, one can expect an emission rate representing the release of CO_2 associated with electricity purchased from the utility company to be higher during peak hours than during off-peak hours.

$baseCO_2EF_{r,h}$ is the CO_2 emission rate for region r (northern or southern California) for hour *h.*

Source: Energy + Environmental Economics

Units: Metric tons / kWh

Electric Power Plant Operations Corresponding to Electric Chiller Operation

An absorption chiller may be used to convert heat recovered from SGIP CHP projects into chilled water to serve buildings or process cooling loads. Since absorption chillers replace the use of electric chillers that operate using electricity from a central power plant, there are avoided CO_2 emissions associated with these cogeneration facilities.

$COOLING_{i,h} = CHILLER_i \cdot heathr_{i,h} \cdot COP$

Where:

$COOLING_{i,h}$ is the cooling services provided by SGIP CHP project i for hour h.

Units: MBtu

$CHILLER_i$ is an allocation factor whose value depends on the SGIP CHP project design (i.e., heating only, heating & cooling, or cooling only)

Value: 1, 0.5, or 0. See Table C-2.

Table C-2: Assignment of Chiller Allocation Factor

Project Design	$CHILLER_i$
Heating & Cooling	0.5
Cooling Only	1
Heating Only	0

Units: Dimensionless

Basis: Project design as represented in installation verification inspection report

$heathr_{i,h}$ is the quantity of useful heat recovered for SGIP CHP project *i* for hour *h*.

Units: MBtu

Basis: Metering or ratio analysis depending on availability of useful heat recovery data

COP is the efficiency of the absorption chiller using heat from the SGIP CHP project.

Value: 0.6

Units: $MBtu_{out}$ / $MBtu_{in}$

Basis: Assumed

The electricity that would have been serving an electric chiller in the absence of the cogeneration system was calculated as:

$$chlrElec_{i,h} = COOLING_{i,h} \cdot effElecChlr \cdot \left(\frac{1\ ton \cdot hr\ cooling}{12\ MBtu}\right)$$

Where:

chlrElec$_{i,h}$ is the electricity a power plant would have needed to provide for a baseline electric chiller for SGIP CHP project *i* for hour *h*.

Units: kWh

effElecChlr is the efficiency of the baseline new standard efficiency electric chiller

Value: 0.634

Units: kWh / ton·hr cooling

Basis: assumed

Baseline GHG Emissions from Power Plant Operations

The location- and hour-specific CO_2 emission rate, when multiplied by the quantity of electricity generated for each baseline scenario, estimates the hourly emissions avoided.

$basePpChiller_{i,h} = baseCO_2EF_{i,h} \cdot chlrElec_{i,h}$

$basePpEngo_{i,h} = baseCO_2EF_{i,h} \cdot engohr_{i,h}$

Where:

$basePpChiller_{i,h}$ is the baseline power plant GHG emissions avoided due to SGIP CHP project i delivery of cooling services for hour h.

Units: Metric Ton CO_2 / hr

$basePpEngo_{i,h}$ is the baseline power plant GHG emissions avoided due to SGIP CHP project i electricity generation for hour h.

Units: Metric Ton CO_2 / hr

Boiler GHG Emissions (baseBlr)

A heat exchanger is typically used to transfer useful heat recovered from SGIP CHP projects to building heating loads. The equation below represents the process by which heating services provided by SGIP CHP projects are calculated.

$HEATING_{i,h} = BOILER_i \cdot heathr_{i,h} \cdot effHx$

Where:

$HEATING_{i,h}$ is the heating services provided by SGIP project *i* for hour *h.*

Units: MBtu

$BOILER_i$ is an allocation factor whose value depends on SGIP CHP project design (i.e., heating only, heating & cooling, or cooling only)

Value: 1, 0.5, or 0. See Table C-3.

Table C-3: Assignment of Boiler Allocation Factor

Project Design	$CHILLER_i$
Heating & Cooling	0.5
Cooling Only	0
Heating Only	1

Units: Dimensionless

Basis: Project design as represented in installation verification inspection report

$heathr_{i,h}$ is the quantity of useful heat recovered for SGIP CHP project *i* for hour *h*.

Units: MBtu

Basis: Metering or ratio analysis depending on availability of useful heat recovery data

effHx is the efficiency of the SGIP CHP project's primary heat exchanger

Value: 0.9

Units: Dimensionless fractional efficiency

Basis: Assumed

Baseline natural gas boiler CO_2 emissions were calculated based upon hourly useful heat recovery values for the SGIP CHP project as follows:

$$baseBlr_{i,h} = HEATING_{i,h} \cdot \frac{1}{effBlr} \cdot \left(\frac{1\,ft^3\ of\ CH_4}{935\ Btu}\right)\left(\frac{1{,}000\ Btu}{1\ MBtu}\right)\left(\frac{1\ lbmole\ CO_2}{1\ lbmole\ CH_4}\right)\left(\frac{1\ lbmole\ of\ CH_4}{379\ ft^3\ of\ CH_4}\right)\left(\frac{44\ lbs\ of\ CO_2}{1\ lbmole\ of\ CO_2}\right)\left(\frac{1\ metric\ ton\ CO_2}{2{,}205\ lbs\ CO_2}\right)$$

Where:

$baseBlr_{i,h}$ is the CO_2 emissions of the baseline natural gas boiler for SGIP CHP project *i* for hour *h*

Units: Metric Tons CO_2 / hr

effBlr is the efficiency of the baseline natural gas boiler

Value: 0.8

Units: $MBtu_{out}$ / $MBtu_{in}$

Basis: Previous program cost-effectiveness evaluations.

This equation reflects the ability to use recovered useful heat in lieu of natural gas and, therefore, help reduce CO_2 emissions.

Biogas GHG Emissions (baseBio)

DG projects powered by renewable biogas carry an additional GHG reduction benefit. The baseline treatment of biogas is an influential determinant of GHG impacts for renewable-fueled SGIP projects.

Baseline treatment refers to the typical fate of the biogas in lieu of use for energy purposes (e.g., the biogas could be vented directly to the atmosphere or flared).

There are two common sources of biogas found within the SGIP: landfills and digesters. Digesters in the SGIP to date have been associated with wastewater treatment plants (WWTP), food processing facilities, and dairies. Because of the importance of the baseline treatment of biogas in the GHG analysis, these facilities were contacted in 2009 to more accurately estimate baseline treatment. This resulted in the determination that venting is the customary baseline treatment of biogas for dairy digesters, and flaring is the customary baseline for all other renewable fuel sites. For dairy digesters, landfills, WWTPs, and food processing facilities larger than 150 kW, this is consistent with PY07 and PY08 SGIP impact evaluation reports. However, for WWTPs and food processing facilities smaller than 150 kW, PY07 and PY08 SGIP impact evaluations assumed a venting baseline, whereas in PY09-PY13 impact evaluations the baseline is more accurately assumed to be flaring. Additional information on baseline treatment of biogas per biogas source and facility type is provided below.

For dairy digesters the baseline is usually to vent any generated biogas to the atmosphere. Of the approximately 2,000 dairies in California, conventional manure management practice for flush dairies[6] has been to pump the mixture of manure and water to an uncovered lagoon. Naturally occurring anaerobic digestion processes convert carbon present in the waste into CO_2 and CH_4. These lagoons are typically uncovered, so all CH_4 generated in the lagoon escapes into the atmosphere. Currently, there are no statewide requirements that dairies capture and flare the biogas, although some air pollution control districts are considering anaerobic digesters as a possible Best Available Control Technology (BACT) for volatile organic compounds. This information and the site contacts support a biogas venting baseline for dairies.

For other digesters, including WWTPs and food processing facilities, the baseline is not quite as straightforward. There are approximately 250 WWTPs in California, and the larger facilities (i.e., those that could generate 1 MW or more of electricity) tend to install energy recovery systems; therefore, the baseline assumption for these facilities in past SGIP impact evaluations was flaring. However, in some previous SGIP impact evaluations, it was assumed that most of the remaining WWTPs do not recover energy and flare the gas on an infrequent basis. Consequently, for smaller facilities (i.e., those with capacity less than 150 kW), venting of the biogas (CH_4) was used in PY07 and PY08 SGIP impact evaluations as the baseline. However, all renewable-fueled distributed generation WWTPs and food processing facilities participating in the SGIP that were contacted in 2009 said that they flare biogas, and cited local air and water regulations as the reason. Therefore, flaring was used as the biogas baseline for the PY09-PY13 impact evaluation reports.

Defining the biogas baseline for landfill gas recovery operations presented a challenge in past SGIP impact evaluations. A study conducted by the California Energy Commission in 2002[7] showed that landfills with biogas capacities less than 500 kW would tend to vent rather than flare their landfill gas by a margin of more than three to one. In addition, landfills with over 2.5 million metric tons of waste are required to

6 Most dairies manage their waste via flush, scrape, or some mixture of the two processes. While manure management practices for any of these processes will result in CH_4 being vented to the atmosphere, flush dairies are the most likely candidates for installing anaerobic digesters (i.e., dairy biogas projects).

7 California Energy Commission. Landfill Gas-to-Energy Potential in California. 500-02-041V1. September 2002. http://www.energy.ca.gov/reports/2002-09-09_500-02-041V1.PDF

collect and either flare or use their gas. Installation verification inspection reports and renewable-fueled DG landfill site contacts verified that they would have flared their CH_4 in the absence of the SGIP. Therefore, the biogas baseline assumed for landfill facilities is flaring of the CH_4.

In CPUC Decision 09-09-048 (September 24, 2009), eligibility for renewable fuel use incentives was expanded to include "directed biogas" projects. Deemed renewable fuel use projects, directed biogas projects are eligible for higher incentives under the SGIP. Directed biogas projects purchase biogas fuel that is produced at another location. The procured biogas is processed, cleaned-up, and injected into a natural gas pipeline for distribution. Although the purchased gas is not likely to be delivered and used at the SGIP renewable fuel use project, directed biogas projects are treated in the SGIP as renewable fuel use projects.

For directed biogas projects where the biogas is injected into the pipeline outside of California, information on the renewable fuel baseline was not available.[8] To establish a directed biogas baseline the following assumptions were made:

- The renewable fuel baseline for all directed biogas projects is flaring biogas[9], and
- Seventy-five percent of the energy consumed by directed biogas SGIP projects on an energy basis (the minimum amount of biogas required to be procured by a directed biogas project) is assumed to have been injected at the biogas source.

If a directed biogas project is known to have not received any directed biogas during the reporting period, the biogas baseline is set to zero. The GHG emissions characteristics of biogas flaring and biogas venting are very different and, therefore, are discussed separately below.

GHG Emissions of Flared Biogas

CH_4 is naturally created in landfills, wastewater treatment plants, and dairies. If not captured, the methane escapes into the atmosphere contributing to GHG emissions. Capturing the CH_4 provides an opportunity to use it as a fuel. When captured CH_4 is not used to generate electricity or satisfy heating or cooling loads, it is burned in a flare.

In situations where flaring occurs, baseline GHG emissions comprise CO_2 only. The flaring baseline was assumed for the following types of biogas projects:

- Facilities using digester gas (with the exception of dairies),
- Landfill gas facilities, and
- Projects fueled by directed biogas.

The assumption is that the flaring of CH_4 would have resulted in the same amount of CO_2 emissions as occurred when the CH_4 was captured and used in the SGIP project to produce electricity.

8 Information on consumption of directed biogas at SGIP projects is based on invoices instead of metered data.

9 From a financial feasibility standpoint, directed biogas was assumed to be procured only from large biogas sources, such as large landfills. In accordance with Environmental Protection Agency (EPA) regulations for large landfills, these landfills would have been required to collect the landfill gas and flare it. As a result, the basis for directed biogas projects was assumed to be flaring.

$$baseBio_{i,h} = sgipGHG_{i,h}$$

GHG Emissions of Vented Biogas

CH_4 capture and use at renewable fuel use facilities where the biogas baseline is venting avoids release of CH_4 directly into the atmosphere. The venting baseline was assumed for all dairy digester SGIP projects. Biogas consumption is typically not metered at SGIP projects. Therefore, CH_4 emission rates were calculated by assuming an electrical efficiency.

$$CH_4EF_T = \left(\frac{3{,}412\ Btu}{kWh}\right)\left(\frac{1}{EFF_T}\right)\left(\frac{1\ ft^3\ of\ CH_4}{935\ Btu}\right)\left(\frac{1\ lbmole\ of\ CH_4}{379\ ft^3\ of\ CH_4}\right)\left(\frac{16\ lbs\ of\ CH_4}{lbmole\ of\ CH_4}\right)\left(\frac{454\ grams}{lb}\right)$$

Where:

CH_4EF_T is the CH_4 capture rate for SGIP projects of technology T

Units: grams / kWh

EFF_T is the electrical efficiency of technology T.

Value: Dependent on technology type (see Table C-1)

Units: Dimensionless fractional efficiency

Basis: Lower heating value (LHV). Metered data collected from natural gas CHP projects.

The derived CH_4 emission rates (CH_4EF_T) are multiplied by the total electricity generated from the SGIP renewable fuel use project to estimate baseline CH_4 emissions.

$$baseBioCH_{4i,h} = CH_4EF_T \cdot engohr_{i,h} \cdot \left(\frac{1\ lb}{454\ grams}\right)\left(\frac{1\ metric\ ton}{2{,}205\ lbs}\right)$$

The avoided metric tons of CH_4 emissions were then converted to metric tons of CO_2eq by multiplying the avoided CH_4 emissions by 21, which represents the global warming potential of CH_4 (relative to CO_2) over a 100-year time horizon.

$$baseBio_{i,h} = baseBioCH_{4i,h} \cdot \left(\frac{21\ metric\ tons\ CO_2}{1\ metric\ ton\ CH_4}\right)$$

C.4 Build Margin Baseline Discussion

In Decision (D.) 15-11-026 (November 19, 2015), the California Public Utilities Commission (CPUC) revised the GHG emission factor to determine eligibility to participate in the Self-Generation Incentive Program (SGIP) pursuant to Public Utilities Code Section 379.6(b)(2) as amended by Senate Bill (SB) 861. Subsequently, the CPUC directed Itron to incorporate the methodology discussion in this Decision into the 2014-2015 SGIP Impact Evaluation Report. This section describes the implementation of the revised GHG eligibility criteria in parallel to the impact methodology used to estimate GHG emissions. In particular, the

GHG build margin approach does not replace the GHG estimates developed in the impact analysis approach but instead provides a way to compare the GHG emissions estimated with the build margin against the GHG eligibility criteria.

Overview

Traditionally, the SGIP Impact Evaluation reports have adopted a methodology originally developed by Energy and Environmental Economics (E3) for treating GHG emissions avoided by energy efficiency measures. Similar to the logic employed by E3 for energy efficiency measures, we assume that SGIP technologies influence the marginal emissions from the electricity generation system. We assume that electricity generated by SGIP technologies installed on-site avoids the generation of electricity from the last generator to clear the CAISO market. The characteristics of this marginal generator are based on market prices for electricity and natural gas during the period in question. High electricity prices imply that a low-efficiency (high emissions) natural gas plant is able to clear the market and is therefore on the margin. Moderately low electricity prices imply that a high-efficiency (low emissions) natural gas combined-cycle plant is on the margin. Extremely low or negative electricity prices imply that renewables (zero emissions) are on the margin and therefore are being avoided by SGIP generation. In D. 15-11-026 this effect is called the "operating margin" effect.

D. 15-11-026 agrees that SGIP technologies influence the operating margin but goes on to pose that SGIP technologies also influence the construction of future grid-scale generation technologies. D. 15-11-026 calls this effect the "build margin" effect. Section 3.1.2 of D. 15-11-026 states:

"… the Commission assumed SGIP projects would avoid the need for new generation, meaning that the Commission found that SGIP projects affect the build margin and avoid the need for utilities to procure new renewable capacity as well as new fossil-fired capacity."

The following sections describe how we propose to incorporate this build margin approach as a parallel approach to the historical method for calculating GHG emissions into the 2014-2015 impact evaluation report.

Assumptions

Itron's adoption of the build margin approach will borrow heavily from the assumptions made in D. 15-11-026. However, note that the purpose of D. 15-11-026 is to establish eligibility criteria for SGIP projects. This inherently requires a forward-looking approach that makes assumptions about performance and system degradation. An impact evaluation is traditionally backward-looking in that it summarizes past performance and has the benefit of relying on actual performance data. The assumptions made in this document may differ from those made in D. 15-11-026 when performance assumptions are replaced with actual operational data. Below we highlight some of the areas where Itron's assumptions deviate from D. 15-11-026.

Operating Margin Calculation

When quantifying the operating margin emissions, D. 15-11-026 relies on literature values for typical natural gas plant efficiencies and the fraction of time that high efficiency combined cycle gas plants are on the margin relative to low efficiency simple cycle gas plants. The following values are used in the decision:

» High efficiency heat rate: 7,205 Btu/kWh
» Low efficiency heat rate: 10,268 Btu/kWh
» Peaker plant weighting factor: 10%

The methodology used in the 2014-2015 Impact Evaluation Report will continue to rely on the market price shapes approach to quantify the operating margin effect for the following reasons:

» Relying on the market price approach provides an 8,760 hourly dataset of emissions rates, rather than a single average emissions rate. This allows us to more accurately quantify impacts for technologies that only operate during particular hours of the year. It also allows us to quantify the impacts of advanced energy storage.
» The market price approach accounts for hours of over-generation where renewable may be on the margin. The approach in D. 15-11-026 assumes natural gas is always on the margin.

SGIP Performance Over Time

D. 15-11-026 makes several assumptions about the performance of SGIP projects over time. These assumptions are necessary because by their nature eligibility criteria must be developed before projects are operational. The SGIP Impact Evaluation Report relies on actual SGIP project performance and therefore does not need to make assumptions about the useful life of projects or the degradation rate.

Build Margin Assumptions

In Section 3.1.2.1 of D. 15-11-026, the CPUC states:

> *In order to account for both types of avoided generation effects while balancing the need for an acceptable level of administrative complexity, we adopt a methodology that assigns equal weight to the short-term and long-term effects over a ten-year time span. In effect, this assumes that SGIP projects have an operating margin effect during the first five years of operations, and a build margin effect thereafter.*

The methodology used in the 2014-2015 Impact Evaluation Report will also assume that the build margin effect manifests itself after five years. However, unlike D. 15-11-026, we will not assume that the effects have equal weight. Instead, we will assume that the operational margin effect is effective from a project's inception in perpetuity and the build margin effect is in place after five years.

D. 15-11-026 also assumes that the percentage of capacity not built as part of the build margin effect is correlated to the California Renewable Portfolio Standard (RPS). The Decision relies on an average RPS portfolio requirement for project years 6 – 10. The approach in the 2014-2015 Impact Report will rely on the actual RPS procurement achieved during 2014 and 2015, based on data from the California Energy Commission (CEC).

Methodology Summary

Operating Margin Component

The operating margin component of the calculation is based on actual 8,760 hourly CO_2 emission rates developed by E3 using market price shapes. The hourly emission rates will be developed for the specific reporting year. SGIP impact evaluations traditionally evaluate performance during a particular calendar year. This is a departure from traditional energy efficiency evaluations that assess performance of projects completed during a particular program year, quantify first-year impacts and use those to estimate lifetime impacts.

The operating margin component of the GHG calculation is:

$$CO_2\ Metric\ Tons_{Operating} = Marginal\ Emissions\ Rate\ \frac{Metric\ Tons}{MWh} \cdot SGIP\ Generation\ MWh$$

Where:

$Marginal\ Emissions\ Rate\ \frac{Metric\ Tons}{MWh}$: Is the marginal emissions rate for a particular hour developed by E3 based on market heat rates.

$SGIP\ Generation\ MWh$: Is the electrical generation of an SGIP project during a particular hour.

The total marginal emissions from a project are calculated as the sum of all hourly avoided CO_2 emissions.

Build Margin Component

The premise of the build margin component is that because of the SGIP, utilities can avoid the construction of new generating capacity, and that a fraction of said capacity would have been zero-emissions renewables. The renewable fraction is correlated to the RPS. To reflect this reduction in renewable capacity, we will modify the hourly marginal emissions rate beginning on the first hour of a project's sixth year in operation. The build margin modified is one minus the RPS percentage applicable the year the project was completed:

$$Build\ Margin\ Modifier = (1 - RPSpct)$$

Where:

$RPSpct$: Is the renewable portfolio standard achieved during the calendar year in question, based on data from the CEC RPS tracking website.

Combined Approach

The hourly avoided electric grid emissions for any SGIP project *(p)* during any hour *(h)* for projects in operational years 1-5 are calculated as:

$$Avoided\ Grid\ GHG_{p,h} = \ SGIP\ Generation\ MWh_{p,h} \cdot \ Marginal\ Emissions\ Rate_h\ \frac{Metric\ Tons}{MWh}$$

Where:

$SGIP\ Generation\ MWH_{p,h}$ is the electrical generation of SGIP project *p* during hour *h*

$Marginal\ Emissions\ Rate_h$ is the marginal emissions rate during hour h

The hourly avoided electric grid emissions for any SGIP project (p) during any hour (h) for projects operating in year six and beyond are calculated as:

$$Avoided\ Grid\ GHG_{p,h} = \left(1 - RPSpct_y\right) SGIP\ Generation\ MWh_{p,h} \cdot Marginal\ Emissions\ Rate_h\ \frac{Metric\ Tons}{MWh}$$

Where:

$RPSpct_y$ is the RPS percentage associated with calendar year y based on data from the CEC RPS tracking.

Summary of GHG Impact Results

Table C-4: GHG Impacts by Technology Type and Energy Source

Technology Type / Energy Source	2014 GHG Impact (Metric Tons CO_2eq)	2015 GHG Impact (Metric Tons CO_2eq)	Overall GHG Impact (Metric Tons CO_2eq)
Fuel Cell – CHP	**-35,155**	**-28,237**	**-63,393**
Non-Renewable	-5,631	-6,120	-11,751
Renewable – Directed	-12,515	-10,517	-23,032
Renewable – Flared	-17,010	-11,600	-28,610
Fuel Cell – Electric Only	**-60,052**	**-61,755**	**-121,806**
Non-Renewable	-9,123	-18,628	-27,750
Renewable – Directed	-50,929	-43,127	-94,056
Gas Turbine	**-8,667**	**19,111**	**10,444**
Non-Renewable	-8,667	19,111	10,444
Internal Combustion Engine	**-4,637**	**-45,182**	**-49,819**
Non-Renewable	21,274	9,064	30,338
Renewable – Flared	-19,740	-28,376	-48,116
Renewable – Vented	-6,171	-25,870	-32,041
Microturbine	**13,789**	**18,085**	**31,873**
Non-Renewable	16,298	20,458	36,756
Renewable – Flared	-2,509	-2,373	-4,882
Pressure Reduction Turbine	**-1,289**	**-2,060**	**-3,350**
Wind	**-20,822**	**-20,925**	**-41,747**

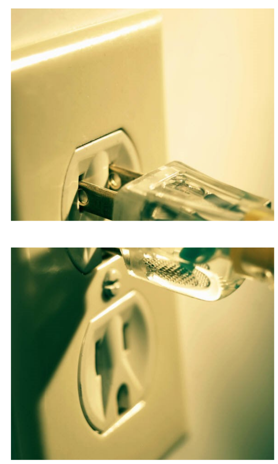
Table C-5: GHG Impacts by Program Administrator and Technology Type

Program Administrator / Technology Type	2014 GHG Impact (Metric Tons CO_2eq)	2015 GHG Impact (Metric Tons CO_2eq)	Overall GHG Impact (Metric Tons CO_2eq)
Center for Sustainable Energy	**-18,830**	**-8,870**	**-27,701**
Fuel Cell – CHP	-11,066	-9,991	-21,057
Fuel Cell – Electric Only	-4,590	-4,095	-8,685
Gas Turbine	57	9,821	9,878
Internal Combustion Engine	-1,536	-1,552	-3,088
Microturbine	-2	-178	-180
Pressure Reduction Turbine	-1,289	-1,251	-2,541
Wind	-404	-1,624	-2,028
Pacific Gas & Electric Company	**-42,483**	**-67,318**	**-109,801**
Fuel Cell – CHP	-8,204	-7,419	-15,623
Fuel Cell – Electric Only	-29,266	-31,907	-61,173
Gas Turbine	-384	7,186	6,803
Internal Combustion Engine	-6,455	-36,928	-42,753
Microturbine	8,383	10,916	19,299
PRT	-	-809	-809
Wind	-6,557	-8,989	-15,546
Southern California Edison	**-40,284**	**-38,192**	**-78,476**
Fuel Cell – CHP	-8,632	-5,699	-14,331
Fuel Cell – Electric Only	-15,596	-15,451	-31,047
Internal Combustion Engine	-2,891	-7,862	-10,753
Microturbine	696	1,132	1,828
Wind	-13,861	-10,313	-24,174
Southern California Gas Company	**-15,237**	**-6,583**	**-21,820**
Fuel Cell – CHP	-7,254	-5,128	-12,382
Fuel Cell – Electric Only	-10,600	-10,302	-20,902
Gas Turbine	-8,340	2,104	-6,237
Internal Combustion Engine	6,245	529	6,774
Microturbine	4,713	6,214	10,926

Table C-6: GHG Impacts by Program Administrator and Energy Source

Program Administrator / Energy Source	2014 GHG Impact (Metric Tons CO_2eq)	2015 GHG Impact (Metric Tons CO_2eq)	Overall GHG Impact (Metric Tons CO_2eq)
Center for Sustainable Energy	**-18,830**	**-8,870**	**-27,701**
Non-Renewable	-537	8,335	7,799
Renewable – Directed	-14,161	-11,851	-26,012
Renewable – Flared	-2,439	-2,479	-4,919
Other	-1,693	-2,875	-4,569
Pacific Gas & Electric Company	**-42,483**	**-67,318**	**-109,801**
Non-Renewable	9,242	9,487	18,729
Renewable – Directed	-25,504	-23,774	-49,278
Renewable – Flared	-13,492	-17,363	-30,855
Renewable – Vented	-6,171	-25,870	-32,041
Other	-6,557	-9,798	-16,355
Southern California Edison	**-40,284**	**-38,192**	**-78,476**
Non-Renewable	1,800	-1,877	-77
Renewable – Directed	-15,288	-11,811	-27,099
Renewable – Flared	-12,936	-14,192	-27,127
Other	-13,861	-10,313	-24,174
Southern California Gas Company	**-15,237**	**-6,583**	**-21,820**
Non-Renewable	3,646	7,940	11,586
Renewable – Directed	-8,491	-6,208	-14,699
Renewable - Flared	-10,392	-8,315	-18,707

Appendix D



APPENDIX D CRITERIA AIR POLLUTANT IMPACTS ESTIMATION IMPACTS ESTIMATION METHODOLOGY AND RESULTS

This appendix describes the methodology used to estimate the impacts of criteria air pollutant emissions from the operation of Self-Generation Incentive Program (SGIP) projects. Criteria air pollutants are those air pollutants having national air quality standards with defined allowable concentrations in ambient air. Criteria air pollutants are carbon monoxide (CO), lead (Pb), oxides of nitrogen (NO_X), ozone (O_3), particulate matter (PM), and sulfur dioxide (SO_2).[1] Ozone is not directly generated by SGIP technologies and therefore ozone impacts are not reported.[2] In addition, there is insufficient information on lead emissions to include an assessment of lead emission impacts. Consequently, criteria air pollutants considered in this analysis are limited to NO_X, SO_2 and particulate matter in the 10 micron size range (PM_{10}).

This appendix is organized in six sections:

- **D.1** provides an overview of the analytic methodology
- **D.2** discusses in detail how NO_X emission rates were developed
- **D.3** discusses in detail how PM_{10} emission rates were developed
- **D.4** discusses in detail how SO_2 emission rates were developed
- **D.5** describes how the emissions rates are implemented into the impacts calculation
- **D.6** presents summary information on criteria air pollutant impacts

D.1 Overview

Criteria air pollutant impacts are estimated using an approach similar to the greenhouse gas (GHG) impacts estimation methodology described in Appendix C. Criteria air pollutant impacts are estimated as the difference between the emissions that occur from operation of SGIP projects and those that would occur from serving electrical, heating, and cooling loads via conventional energy services (i.e., the electricity grid, boilers, and electric chillers) in the absence of the SGIP. The principal difference between the GHG and criteria pollutant impacts methodologies is that the emissions from central station grid generation, boilers, and SGIP generators are not a simple function of the amount of gas consumed. For example, NOX emissions rates are a function of combustion stoichiometry and temperature, which can vary from one internal combustion engine to the next. In addition, post-combustion emission control technologies such as catalysts can significantly impact emissions rates. Emission control requirements can vary by air quality management district (AQMD) and program year (PY). This variability in potential emissions rates necessitates the development of emissions rate estimates that are specific to a given technology, program year, and energy source.

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[1] Environmental Protection Agency, from http://www.epa.gov/air/criteria.html

[2] Ozone or oxidant makes up photochemical smog and NO_X emissions are critical precursors to the formation of oxidant.

The sections below describe the overall approach and assumptions made in estimating emissions rates for each of the criteria air pollutants treated.

D.2 Oxides of Nitrogen (NO_X) Emission Rates

The rate at which NO_X is created is a function of the energy source, the combustion process/chemical reaction, and the type of emissions control technology installed. All fuel-consuming SGIP technologies generate NO_X emissions. Sources of avoided NO_X emissions include central-station grid power plants, natural gas boilers, and biogas flares.

SGIP Project NO_X Emission Rates

NOX emission rates from SGIP projects are based on literature research and personal communications with industry experts conducted by Itron. The amount of NOX produced by each technology type can vary by program year, primary due to changes in air emission requirements imposed by the California Air Resources Board (CARB) and improvements in Best Available Control Technology (BACT). Studies conducted in the 2000 to 2005 timeframe indicated that widespread adoption of distributed generation (DG) technologies could potentially lead to a degradation of air quality due to increased emissions of NO_X from DG systems. Leading into 2000, many of the DG systems operating in California were fueled by diesel and had relatively high NO_X emissions. A 2006 survey of air quality management district regulations on NO_X controls for natural gas-fired reciprocating engines found NO_X requirements ranged from 0.3 lb/MWh in the South Coast AQMD to over 4 lb/MWh. Due to concerns over potential increases in NO_X emissions from DG resources, the Legislature passed Senate Bill 1298 (Bowen/Peace) in September 2000. SB 1298 directed by CARB to develop an air pollution control certification program for DG technologies by January 2003. The CARB certification had a phase-in approach that required increasingly lower NO_X emissions between 2005 and 2007.

Table D-1 lists the NO_X emission rates used to estimate 2014-2015 emissions from SGIP technologies.

Table D-1: NO_X Emission Rates for SGIP Technologies

Technology Type	Program Year	Energy Source	NO_X Emission Rate (Pounds NO_X / MWh)
Fuel Cell – Combined Heat and Power	All	All	0.010
Fuel Cell – Electric Only	All	All	0.002
Gas Turbine	PY01-PY06	All	0.300
	PY07	All	0.070
	PY08-PY15	All	0.070
Internal Combustion Engine / Microturbine	PY01-PY06	All	0.200
	PY07	All	0.135
	PY08-PY15	All	0.070

Due to their chemistry, fuel cells tend to have significantly lower NO_X emissions rates compared to combustion technologies. Prior to PY07, before stringent NO_X control rules went into effect, combustion technologies had the highest NO_X emission rates. All combustion technologies that applied after PY07 are assumed to meet CARB's 0.070 lb / MWh target. During PY07, combustion technologies were eligible for

SGIP incentives if they met the CARB's NOX target either through emission controls or by using a combined heat and power (CHP) offset due to avoided boiler use. Consequently, it cannot be assumed that all PY07 combustion technologies achieved CARB's emissions targets. Instead, PY07 is treated as a transition year for internal combustion engines and microturbines; their average emission rate is assumed to be half way between the PY01-PY06 rate and the CARB 0.070 lb / MWh target. This is a proxy for an assumption that half the projects achieved CARB's target through emissions controls and the other half achieved CARB's target via CHP credits. PY07 gas turbines are assumed to have met CARB's NO_X target using emission controls

Baseline NO_X Emission Rates

Central station power plants and on-site boilers all generate NOX as a result of the combustion of natural gas. Biogas flares also generate NO_X as a result of the combustion of biogas.

Central Station Power Plant NO_X Emission Rates

NOX emissions rates from central station power plants are based on literature research conducted by Itron. Two central station technologies are considered: a new baseload high efficiency combined cycle gas turbine (CCGT), and an old low efficiency simple cycle gas turbine peaker plant. These technologies are considered representative of the best and worst case scenario for marginal emissions. The best and worst case values are then mapped to the best and worst marginal emissions rates. Hourly NO_X emissions rates are interpolated between this maximum and minimum according to the marginal heat rate during any given hour. Table D-2 lists the maximum and minimum NO_X emission rates used to estimate 2014-2015 emissions from baseline central station power plants.

Table D-2: NO_X Emission Rates for Central Station Power Plants

Central Station Marginal Generator	NO_X Emission Rate (Pounds NOX / MWh)
New Baseload Combined Cycle Gas Turbine	0.070
Old Simple Cycle Gas Turbine Peaker	0.246

Boiler and Flare NO_X Emission Rates

NO_X emission rates from natural gas boilers and biogas flares are based on literature research conducted by Itron. In most urban areas in California, air pollution control districts passed regulations in the mid-1990's requiring some form of NO_X control on commercial sized boilers (i.e., boilers in the size range of less than 10 MMBtu heat input up to about 50 MMBtu heat input). In these urban areas (e.g., Bay Area, Southern California, San Diego), the regulations required control of NOX to 30 parts per million by volume (ppmv) at 3% O2. This corresponds to approximately 0.037 lb of NO_X/MMBtu heat input. In non-urban areas of California, boilers were left to meet new source performance standards (NSPS) requirements.

This analysis assumes that two thirds of SGIP projects are in urban areas with the remaining third in non-urban areas and that the average boiler NOX emission rate can be approximated by the following equation:

Table D-3 lists the NO_X emission rates used to estimate 2014-2015 emissions from baseline natural gas boilers and biogas flares.

Table D-3: NO_X Emission Rates For Natural Gas Boilers And Biogas Flares

Baseline Component	NOX Emission Rate (Pounds NO_X / MMBtu)
Natural Gas Boiler	0.088
Biogas Flare	0.056

Venting of biogas to the atmosphere does not produce NO_X, therefore, there is no avoided NO_X component for projects that would have otherwise vented biogas.

D.3 Particulate Matter Emission Rates

Particulate matter is a complex mixture of extremely small particles and liquid droplets. The size of particles is directly linked to their potential for causing health problems. The Environmental Protection Agency (EPA) is concerned about particles that are 10 micrometers in diameter or smaller because those are the particles that generally pass through the throat and nose and enter the lungs. Once inhaled, these particles can affect the heart and lungs and cause serious health effects. As with NO_X, the rate at which PM10 is created is a function of the energy source, the combustion process/chemical reaction, and the types of emissions controls installed. All fuel-consuming SGIP technologies generate PM10 emissions. Sources of avoided PM10 emissions include central-station grid power plants, natural gas boilers, and biogas flares.

SGIP Project PM_{10} Emission Rates

PM_{10} emissions rates from SGIP projects are based on literature research and personal communications with industry experts conducted by Itron staff. Table D-4 lists the PM10 emission rates used to estimate 2014-2015 emissions from SGIP projects.

Table D-4: PM_{10} Emission Rates for SGIP Technologies

Technology Type	Program Year	Energy Source	PM10 Emission Rate (Pounds PM10 / MWh)
Fuel Cell – CHP or Electric Only	All	All	0.00002
Gas Turbine	All	Natural Gas	0.05635
Internal Combustion Engine	All	Natural Gas	0.06006
	All	Biogas	0.06969
Microturbine	All	All	0.08575

As with NO_X, fuel cells have the lowest PM_{10} emissions rates when compared to combustion technologies.

BASELINE PM_{10} EMISSION RATES

Central station power plants and on-site boilers all generate PM_{10} as a result of the combustion of natural gas. Biogas flares also generate PM10 as a result of the combustion of biogas.

Central Station Power Plant PM10 Emission Rates

PM_{10} emissions rates from central station power plants are based on literature research conducted by Itron. Table D-5 lists the PM_{10} emission rates used to estimate 2014-2015 emissions from central station power plants.

Table D-5: PM_{10} Emission Rates for Central Station Power Plants

Central Station Marginal Generator	PM_{10} Emission Rate (Pounds PM_{10} / MWh)
New Baseload Combined Cycle Gas Turbine	0.03000
Old Simple Cycle Gas Turbine Peaker	0.11456

Hourly PM_{10} emission rates from central station power plants are interpolated using the same methodology described above for NO_X emissions.

Boiler and Flare PM_{10} Emission Rates

PM_{10} emission rates from natural gas boilers and biogas flares are based on literature research conducted by Itron. Table D-6 lists the PM_{10} emission rates used to estimate 2014-2015 emissions from natural gas boilers and biogas flares.

Table D-6: PM_{10} Emission Rates for Natural Gas Boilers and Biogas Flares

Baseline Component	PM_{10} Emission Rate (Pounds PM_{10} / MMBtu)
Natural Gas Boiler	0.00773
Biogas Flare	0.01418

Venting of biogas to the atmosphere does not produce PM_{10}, therefore, there is no avoided PM_{10} component for projects that would have otherwise vented biogas.

D.4 Sulfur Dioxide (SO_2) Emission Rates

Sulfur dioxide is one of a group of highly reactive gasses known as "oxides of sulfur." Existing literature on SO_2 emissions from natural gas generation are limited. In general, SO_2 emissions from combustion processes are due to the oxidation of sulfur compounds contained in the fuel. To estimate SO_2 emission rates, reported concentrations of sulfur in the fuel (natural gas or biogas) are used and it is assumed that all of the sulfur in the fuel is converted to SO_2. This provides a conservatively high estimate of SO_2 emissions as not all of the sulfur in the fuel may actually be converted to SO_2.

SGIP PROJECT SO_2 EMISSION RATES

SGIP project energy sources are the primary driver of SO_2 emissions from SGIP projects. The amount of sulfur in biogas is significantly higher than the sulfur content of pipeline quality natural gas. The following sections describe the assumptions employed to arrive at SO_2 emission rates for non-renewable and renewable projects.

SGIP Project SO_2 Emission Rates from Natural Gas

Natural gas contains very low concentrations of sulfur compounds. Gas utilities may add sulfur compounds to odorize the gas for safety purposes. Sulfur compounds typically found in natural gas consist of Tetrahydrothiophene (THT), Tertiary Butyl Mercaptan (TBM), Dimethyl Sulfide (DMS), and Hydrogen Sulfide (H_2S).[3] Both Pacific Gas & Electric Company (PG&E) and Southern California Gas Company (SCG) restrict the amount of sulfur compounds that can be contained in natural gas transported in the natural gas pipelines through Gas Rule 21. Gas Rule 21 limits the amount of sulfur compounds in natural gas to the following levels:

- Total Sulfur: The gas shall contain no more than one grain (17 ppm) of total sulfur per one hundred standard cubic feet.
- Mercaptan Sulfur: The gas shall contain no more than 0.5 grain (8 ppm) of mercaptan sulfur per one hundred standard cubic feet.
- Hydrogen Sulfide: The gas shall contain no more than 0.25 grain (4 ppm) of hydrogen sulfide per one hundred standard cubic feet.

The limits above represent maximum concentrations of sulfur contained in natural gas. PG&E also provides information on representative sulfur concentrations for natural gas during 2013 as shown in Table D-7. In practice, natural gas has lower concentrations of total sulfur. The 2013 average value from all sites of 0.173 grains per hundred standard cubic feet (2.91 ppmv) is used as a representative value of total sulfur contained in natural gas.

Table D-7: Representative Total Sulfur Concentrations in Natural Gas

	Total Sulfur			
	Maximum		Average all Sites	
Quarter in 2013	PPMv	gr/100 SCF	PPMv	gr/100 SCF
Fourth	4.99	0.296	2.62	0.156
Third	5.69	0.338	2.89	0.171
Second	7.33	0.435	3.17	0.188
First	6.71	0.398	2.97	0.176
Average	***6.18***	***0.367***	***2.91***	***0.173***

During combustion, sulfur contained in the fuel is converted to SO_2 in accordance with the following chemical equation:

$S + O_2 \rightarrow SO_2$

[3] From PG&E's Gas Transmission website: http://www.pge.com/pipeline/operations/sulfur/sulfur_info.shtml

Using the representative concentration of sulfur in natural gas and the above chemical equation, SO_2 emission rates in units of pounds of SO_2 per MWh of generated electricity are estimated as follows:[4]

$$SO_{2,T}\frac{lb}{MWh}=\left(\frac{0.00000025\ lb\ S}{scf\ natgas}\right)\cdot\left(\frac{3412\ Btu}{kWh}\right)\cdot\left(\frac{1}{EFF_T}\right)\left(\frac{1\ scf\ natgas}{935\ Btu}\right)\left(\frac{64\ lb\ SO_2}{lbmole\ SO_2}\right)\left(\frac{1\ lbmole\ SO_2}{1\ lbmole\ S}\right)\left(\frac{1\ lbmole\ S}{32\ lb\ S}\right)\left(\frac{1{,}000\ kWh}{1\ MWh}\right)$$

Where EFF_T refers to the electrical efficiency of the technology as defined in Table D-8.

Table D-8: Electrical Efficiency by Technology Type Used for SO_2 Emissions Calculation

Technology Type (T)	2014 Electrical Efficiency (EFF_T)	2015 Electrical Efficiency (EFF_T)
Gas Turbine	0.372	0.326
Internal Combustion Engine	0.291	0.315
Microturbine	0.224	0.219

Table D-9 lists the SO_2 emission rates used to estimate 2013 emissions from SGIP projects fueled by natural gas using the equation above. Note that fuel cells are assumed to have lower tolerances for sulfur and, therefore, the SO_2 emission rates are based on values in the literature.

Table D-9: SO_2 Emission Rates for SGIP Projects Fueled by Natural Gas

Technology Type	Program Year	Energy Source	SO_2 Emission Rate (Pounds SO_2 / MWh)
Fuel Cell – CHP	All	Natural Gas	0.0001
Fuel Cell – Electric Only	All	Natural Gas	0.0001
Gas Turbine	All	Natural Gas	0.0050
Internal Combustion Engine	All	Natural Gas	0.0062
Microturbine	All	Natural Gas	0.0078

SGIP Project SO_2 Emission Rates from Renewable Biogas

Biogas is a mixture of methane, carbon dioxide, water and a variety of other trace compounds. In general, the biogas contains approximately 60 to 70 percent by volume of methane.[5] For the purposes of this analysis, biogas is assumed to have an energy content of approximately 600 Btu per standard cubic foot (Btu/scf). Sulfur compounds are among the different trace gas mixtures found in biogas. Typically, anaerobic processes produce hydrogen sulfide. Concentrations of H_2S can vary significantly from site to site and by resource type (e.g., landfill gas operations versus dairy digesters). For example, H_2S concentrations can range from 500 to over 2,500 ppmv at wastewater treatment plants. However, H_2S poses corrosion issues to most generation equipment and must be reduced through biogas cleaning

4 0.173 grains of sulfur/100 scf is approximately equal to 0.00000025 lbs of sulfur/scf of natural gas

5 http://www.biogas-renewable-energy.info/biogas_composition.html

processes. Based on operational considerations, biogas used in PY01-PY06 internal combustion engines is usually controlled to less than 200 ppmv.[6] For PY01-PY06 internal combustion engines, the sulfur concentration in the biogas is assumed to be a maximum of 200 ppmv. Internal combustion engines deployed after PY07 are required to meet CARB NO_X requirements, which necessitate the use of post-combustion control technologies such as selective catalytic reduction (SCR) systems. SCR systems can be poisoned by even small amounts of sulfur compounds. As a result, sulfur concentrations of 5 ppmv are assumed for PY08-PY13 internal combustion engines to protect post-combustion air pollution control equipment. As with NO_X emissions, PY07 is treated as a transition year for biogas internal combustion engines; the SO_2 emission rate is assumed to be halfway between the PY06 and PY08 emission rate.

The following chemical equation is used for the oxidation of H_2S to SO_2 during combustion of biogas:

$2H_2S + 3O_2 \rightarrow 2H_2O + 2SO_2$

Using the above chemical reaction equation, SO_2 emission rates in units of pounds of SO_2 per MWh of generated electricity from SGIP generators are estimated as follows:

$$SO_{2,T}\frac{lb}{MWh} = \left(\frac{X_T\ scf\ H_2S}{scf\ biogas}\right)\cdot\left(\frac{3412\ Btu}{kWh}\right)\cdot\left(\frac{1}{EFF_T}\right)\left(\frac{1\ scf\ biogas}{600\ Btu}\right)\left(\frac{64\ lb\ SO_2}{lbmole\ SO_2}\right)\left(\frac{1\ lbmole\ SO_2}{1\ lbmole\ H_2S}\right)\left(\frac{1\ lbmole\ H_2S}{379\ scf\ H_2S}\right)\left(\frac{1{,}000\ kWh}{1\ MWh}\right)$$

Where: X_T refers to the volumetric concentration of H_2S in the biogas.

Based on assumed concentrations of sulfur in the fuel and measured electrical efficiencies of SGIP generators, Table D-10 lists SO_2 emission rates for SGIP generators fueled by biogas.

Table D-10: Estimated SO_2 Emission Rates for SGIP Generators Fueled by Biogas

Technology Type	Program Year	Sulfur Content (ppmv)	SO_2 Emission Rate (Pounds SO_2 / MWh)
Fuel Cell – CHP	All	--	0.0001
Internal Combustion Engine	PY01-PY06	200	0.6623
	PY07	--	0.3394
	PY08-PY15	5	0.0166
Microturbine	PY01-PY15	5	0.0209

Fuel cell operations require very low biogas sulfur concentrations. Consequently, the SO_2 emission rate for fuel cells is obtained from the literature.

[6] Department of Ecology, State of Washington, “Technical Support Document for Dairy Manure Anaerobic Digester Systems with Digester Gas Fueled Engine Generators,” March 2012

Baseline SO_2 Emissions Rates

Central Station Power Plant SO_2 Emission Rates

Central station power plant SO_2 emission rates are calculated in the same manner as SGIP generator emissions but assuming different electrical conversion efficiencies (EFF_T). The assumed efficiencies and resulting SO_2 emission rates are listed in Table D-11.

Table D-11: Estimated SO_2 Emission Rates for Central Station Power Plants

Central Station Marginal Generator	Sulfur Content (gr/100 scf)	EFF_T (%)	SO_2 Emission Rate (Pounds SO_2 / MWh)
New Baseload Combined Cycle Gas Turbine	0.173	0.55	0.0033
Old Simple Cycle Gas Turbine Peaker	0.173	0.30	0.0060

Hourly SO_2 emission rates from central station power plants are interpolated using the same methodology described above for NO_X emissions.

Boiler and Flare SO_2 Emission Rates

Natural gas boilers are assumed to have burned gas with total sulfur concentrations of 0.173 grains per 100 scf. Any biogas flares associated with PY01-PY06 internal combustion engines are assumed to have burned biogas with sulfur concentrations of 200 ppmv while all other biogas flares are assumed to have burned biogas with sulfur concentrations of 5 ppmv.

Based on the above assumptions for H_2S concentrations in biogas, the following SO_2 emission rates (in units of pounds of SO_2 per million Btu of fuel input) are obtained for natural gas boilers and biogas flares at SGIP projects that consume biogas.

Table D-12: Estimated SO_2 Emission Rates for Natural Gas Boilers and Biogas Flares

Baseline Component	Underlying Technology Type	Underlying Technology Program Year	PM_{10} Emission Rate (Pounds PM_{10} / MMBtu)
Natural Gas Boiler	All	All	0.0005
Biogas Flare	Internal Combustion Engine	PY01-PY06	0.0855
		PY07	0.0435
		PY08-PY15	0.0014
Biogas Flare	Other Than Internal Combustion Engine	All	0.0014

D.5 Emissions Impact Calculations

Criteria pollutant impacts are calculated as the annual sum of hourly SGIP project emissions minus the annual sum of hourly electric power plant emissions, natural gas boiler emissions, and biogas flare emissions for all projects.

$$\Delta Pollut_{i,h} = sgipPollut_{i,h} - (basePpEngoPollut_{i,h} + basePpChillerPollut_{i,h} + baseBlrPollut_{i,h} + baseBioPollut_{i,h})$$

Where:

$\Delta Pollut_{i,h}$ is the criteria pollutant impact for SIGP project i during hour h

Each component of the criteria pollutant impacts calculation is further described below.

SGIP Project Emissions

The emissions from SGIP project operation are calculated as follows:

$$sgipPollut_{i,h} = engohr_{i,h} \cdot sgipPollutRate_i \cdot \frac{1\ MWh}{1{,}000\ kWh}$$

Where:

$sgipPollut_{i,h}$ is the specific criteria pollutant emitted by SGIP project *i* during hour *h*.

Units: pound / hr

$engohr_{i,h}$ is the electrical output of SGIP project *i* during hour *h.*

Units: kWh

Basis: Metered data collected from SGIP projects net of any parasitic losses.

$sgipPollutRate_i$ is the criteria pollutant emissions rate for SGIP project *i*

Units: pounds / MWh

Basis: As defined in Section D.2 (NO_X), D.3 (PM_{10}), or D.4 (SO_2).

Baseline Power Plant Emissions

The baseline power plant criteria pollutant emission rate, when multiplied by the quantity of electricity generated for each baseline scenario, estimates the hourly emissions avoided from central station power plants.

$basePpChillerPollut_{i,h} = powerPlantPollutRate_h \cdot chlrElec_{i,h} \cdot (1\ MWh/1{,}000\ kWh)$

$basePpEngoPollut_{i,h} = powerPlantPollutRate_h \cdot engohr_{i,h} \cdot (1\ MWh/1{,}000\ kWh)$

Where:

$basePpChillerPollut_{i,h}$ is the baseline power plant criteria pollutant emissions avoided due to SGIP CHP project *i* delivery of cooling services for hour *h*.

Units: pound / hr

$basePpEngoPollut_{i,h}$ is the baseline power plant criteria pollutant emissions avoided due to SGIP CHP project *i* electricity generation for hour *h*.

Units: pound / hr

$powerPlantPollutRate_h$ is the baseline power plant criteria pollutant emissions rate

Units: pound / MWh

Basis: As defined in section D.2 (NO_X), D.3 (PM_{10}), or D.4 (SO_2).

$chlrElec_{i,h}$ is the electricity a power plant would have needed to provide for a baseline electric chiller for SGIP CHP project *i* for hour *h*.

Units: kWh

Basis: Defined in Appendix C

Baseline Boiler Emissions

Baseline natural gas boiler criteria pollutant emissions are calculated based upon hourly useful heat recovery values for the SGIP CHP project as follows:

$$baseBlrPollut_{i,h} = HEATING_{i,h} \cdot \frac{1}{effBlr} \cdot blrPolutRate \cdot \left(\frac{1\ MMBtu}{1{,}000\ MBtu} \right)$$

Where:

$baseBlrPollut_{i,h}$ is the criteria pollutant emissions of the baseline natural gas boiler for SGIP CHP project *i* for hour *h*

Units: pound / hr

$HEATING_{i,h}$ is the heating services provided by SGIP project *i* for hour *h.*

Units: MBtu

effBlr is the efficiency of the baseline natural gas boiler

Value: 0.8

Units: $MBtu_{out}$ / $MBtu_{in}$

Basis: Previous program cost-effectiveness evaluations.

$baseBlrPollut_{i,h}$ is the criteria pollutant emissions rate of baseline natural gas boilers

Units: pound / MWh

Basis: As defined in section D.2 (NO_X), D.3 (PM_{10}), or D.4 (SO_2).

Biogas Flaring Emissions

The criteria pollutant emissions due to the flaring of biogas are calculated as follows:

$$baseBioPollut_{i,h} = engohr_{i,h} \cdot \frac{1}{EFF_T} \cdot flarePollutRate_i \cdot \left(\frac{1\ MMBtu}{1{,}000\ MBtu} \right)$$

Where:

$baseBioPollut_{i,h}$ is the criteria pollutant emissions of the baseline biogas flare for SGIP CHP project *i* for hour *h*

Units: pound / hr

$flarePollutRate_i$ is the criteria pollutant emissions rate of the baseline biogas flare for SGIP CHP project *i*

Units: pound / MMBtu

Basis: As defined in section D.2 (NO_X), D.3 (PM_{10}), or D.4 (SO_2).

D.6 Summary of Criteria Air Pollutant Impacts Results

Table D-13: Criteria Pollutant Impacts by Technology Type (2014 and 2015)

Technology Type	NO_X Emission Impact (Pounds NO_X)	PM_{10} Emission Impact (Pounds PM_{10})	SO_2 Emission Impact (Pounds SO_2)
Fuel Cell – CHP	-89,681	-24,153	-1,881
Fuel Cell – Electric Only	-99,358	-45,248	-3,519
Gas Turbine	-10,719	-3,986	320
Internal Combustion Engine	-134,543	-18,900	-13,361
Microturbine	-24,010	171	353
Pressure Reduction Turbine	-891	-400	-31
Wind Turbine	-10,801	-4,825	-389
Total	***-370,003***	***-97,341***	***-18,508***

Table D-14: Criteria Pollutant Impacts by Energy Source (2014 and 2015)

Energy Source	NO_X Emission Impact (Pounds NO_X)	PM_{10} Emission Impact (Pounds PM_{10})	SO_2 Emission Impact (Pounds SO_2)
Non - Renewable	-199,072	-45,728	-1,234
Renewable - Onsite	-119,289	-27,898	-15,418
Renewable - Directed	-39,949	-18,491	-1,436
Other	-11,693	-5,225	-420
Total	***-370,003***	***-97,341***	***-18,508***

Appendix E

APPENDIX E SOURCES OF UNCERTAINTY AND RESULTS

This appendix provides an assessment of the uncertainty associated with Self-Generation Incentive Program (SGIP) impacts estimates. Program impacts discussed include those on energy (electricity, fuel, and heat), as well as those on greenhouse gas (GHG) emissions. The principal factors contributing to uncertainty in the results reported for these two types of program impacts are quite different. The treatment of those factors is described below for each of the two types of impacts.

Uncertainty estimates are provided for annual and peak electrical impacts.

E.1 Overview of Energy (Electricity, Fuel, and Heat) Impacts Uncertainty

Electricity, fuel, and useful heat recovery impacts estimates are affected by at least two sources of error that introduce uncertainty into the population-level estimates: measurement error and sampling error. Measurement error refers to the differences between actual values (e.g., actual electricity production) and measured values (i.e., electricity production values recorded by metering and data collection systems). Sampling error refers to differences between actual values and values estimated for unmetered systems. The estimated impacts calculated for unmetered systems are based on the assumption that performance of unmetered systems is identical to the average performance exhibited by groups of similar metered projects. Very generally, the *central tendency* (i.e., an average) of metered systems is used as a proxy for the central tendency of unmetered systems.

The actual performance of unmetered systems is not known, and will never be known. It is, therefore, not possible to directly assess the validity of the assumption regarding identical central tendencies. However, it is possible to examine this issue indirectly by incorporating information about the performance *variability* characteristics of the systems.

Theoretical and empirical approaches exist to assess uncertainty effects attributable to both measurement and sampling error. Propagation of error equations are a representative example of theoretical approaches. Empirical approaches to quantification of impact estimate uncertainty are not grounded on equations derived from theory. Instead, information about factors contributing to uncertainty is used to create large numbers of possible sets of actual values for unmetered systems. Characteristics of the sets of simulated actual values are analyzed. Inferences about the uncertainty in impacts estimates are based on results of this analysis.

For this impacts evaluation an empirical approach known as Monte Carlo Simulation (MCS) analysis was used to quantify impacts estimates uncertainty. The term MCS refers to "the use of random sampling techniques and often the use of computer simulation to obtain approximate solutions to mathematical or physical problems especially in terms of a range of values each of which has a calculated probability of being the solution."[1]

A principle advantage of this approach is that it readily accommodates complex analytical questions. This is an important advantage for this evaluation because numerous factors contribute to variability in impacts estimates, and the availability of metered data upon which to base impact estimates is variable. For example, metered electricity production and heat recovery data are both available for some

[1] Webster's Dictionary.

cogeneration systems, whereas other systems may also include metered fuel consumption, while still others might have combinations of data available.

E.2 Overview of Greenhouse Gas Impacts Uncertainty

Electricity and fuel impacts estimates represent the starting point for the analysis of GHG emission impacts; thus, uncertainty in those electricity and fuel impacts estimates flows down to the GHG emissions impact estimates. However, additional sources of uncertainty are introduced in the course of the GHG emissions impact analysis. GHG emissions impact estimates are, therefore, subject to greater levels of uncertainty than are electricity and fuel impact estimates. The two most important additional sources of uncertainty in GHG emissions impacts are summarized below.

Baseline Central Station Power Plant GHG Emissions

Estimation of GHG emission impacts for each SGIP project involves comparison of emissions of the SGIP project with emissions that would have occurred in the absence of the program. The latter quantity depends on the central station power plant generation technology (e.g., natural gas combined cycle, natural gas turbine) that would have met the participant's electric load if the SGIP project had not been installed. Data concerning marginal baseline generation technologies and their efficiencies (and, hence, GHG emissions factors) were obtained from Energy + Environmental Economics (E3). Quantitative assessment of uncertainty in E3's avoided GHG emissions rates is outside the scope of this SGIP impacts evaluation.

Baseline Biogas Project GHG Emissions

Biomass material (e.g., trash in landfills, manure in dairies) would typically have existed and decomposed (releasing methane (CH_4)), even in the absence of the program. While the program does not influence the existence or decomposition of the biomass material, it may impact whether or not the CH_4 is released directly into the atmosphere. This is critical because CH_4 is a much more active GHG than are the products of its combustion (e.g., CO_2).

The CH_4 disposition baseline assumptions used in this GHG impact evaluation are summarized in Table E-1. A more detailed treatment of biogas baseline assumptions is included in Appendix C.

Table E-1: Methane Disposition Baseline Assumptions for Biogas Projects

Renewable Fuel Facility Type	Methane Disposition Baseline Assumption
Dairy Digester	Venting
Waste Water Treatment	Flaring
Landfill Gas Recovery	
Directed Biogas	

Due to the influential nature of this factor, and given the current relatively high level of uncertainty surrounding assumed baselines, this evaluation continues to incorporate site-specific information about CH_4 disposition into impacts analyses.

E.3 Sources of Data for Uncertainty Analysis

The usefulness of MCS results rests on the degree to which the factors underlying the simulations of actual performance of unmetered systems resemble factors known to influence those SGIP projects for which impacts estimates are being reported. Several key sources of data for these factors are described briefly below.

SGIP Project Information

Basic project identifiers include PA, payment status, project location, technology type, fuel type, and project size. This information is obtained from the statewide database maintained by Energy Solutions on behalf of the Program Administrators (PAs). More detailed project information (e.g., heat exchanger configuration) is obtained from site inspection verification reports developed by the PAs' consultants just prior to issuance of incentive payments.

Metered Data for SGIP Projects

Collection and analysis of metered performance data for SGIP projects is a central focus of the overall program evaluation effort. In the MCS study, the metered performance data are used for two principal purposes:

1. Metered data are used to estimate the actual performance of metered systems. The metered data are not used directly for this purpose. Rather, information about measurement error is applied to metered values to estimate actual values.
2. The variability characteristics exhibited by groups of metered data contribute to development of distributions used in the MCS study. Values from the distributions are randomly picked to estimate the performance of unmetered systems in large numbers of simulation runs to explore the likelihood that actual total performance of groups of unmetered systems deviates by certain amounts from estimates of their performance.

Manufacturer's Technical Specifications

Metering systems are subject to measurement error. The values recorded by metering systems represent very close approximations to actual performance; they are not necessarily identical to actual performance. Technical specifications available for metering systems provide information necessary to characterize the difference between measured and actual performance.

E.4 Uncertainty Analysis Analytic Methodology

The analytic methodology used for the MCS study is described in this section. The discussion is broken down into five steps:

- Ask Question

- Design Study
- Generate Sample Data
- Calculate the Quantities of Interest for Each Sample
- Analyze Accumulated Quantities of Interest

Ask Question

The first step in the MCS study is to clearly describe the question(s) that the MCS study was designed to answer. In this instance, that question is: How confident can one be that *actual* program total impact deviates from *reported* program total impact by less than certain amounts? The scope of the MCS study includes the following program total impacts:

- Program Total Annual Electrical Energy Impacts
- Program Total Coincident Peak Electrical Demand Impacts
- Program Total System Efficiency

Design Study

The MCS study's design determines requirements for generation of sample data. The process of specifying study design includes making tradeoffs between flexibility, accuracy, and cost. This MCS study's tradeoffs pertain to treatment of the dynamic nature of the SGIP and to treatment of the variable nature of data availability. Some of the projects came online during 2015 and, therefore, contributed to energy impacts for only a portion of the year. Some of the projects for which metered data are available have gaps in the metered data archive that required estimation of impacts for a portion of hours during 2014 and 2015. These issues are discussed below.

Sample data for each month of the year could be simulated, and then annual electrical energy impacts could be calculated as the sum of the monthly impacts. Alternatively, sample energy production data for entire years could be generated. An advantage of the monthly approach is that it accommodates systems that came online during 2015, and, therefore, contributed to energy impacts for only a portion of the year. The disadvantage of using monthly simulations is that this approach is 12 times more processor-intensive than an annual simulation approach.

A central element of the MCS study involves generation of actual performance values (i.e., sample data) for each simulation run. The method used to generate these values depends on whether or not the project is metered. However, for many of the SGIP projects, metered data are available for a portion – but not all – of 2014 and 2015. This complicates any analysis that requires classification of projects as either "metered" or "not metered."

An effort was made to accommodate the project status and data availability details described above without consuming considerable time and resources. To this end, two important simplifying assumptions are included in the MCS study design.

1. Each data archive (e.g., electricity, fuel consumption, useful heat recovery) for each month for each project is classified as being either "metered" (at least 90% of any given month's reported impacts are based on metered data) or "unmetered" (less than 90% of any given month's reported impacts are based on metered data) for MCS purposes.

2. An operations status of "Normal" or "Unknown" was assigned to each month for each unmetered system based on a telephone survey of participants.[2]

Generate Sample Data

Actual values for each of the program impact estimates identified above ("Ask Question") are generated for each sample (i.e., "run" or simulation).

If metered data are available for the project, then the actual values are created by applying a measurement error to the metered values. If metered data are not available for the project, the actual values are created using distributions that reflect performance variability assumptions. *A total of 1,000 simulation runs were used to generate sample data.*

Metered Data Available – Generating Sample Data that Include Measurement Error

The assumed characteristics of random measurement-error variables are summarized in Table E-2. The ranges are based on typical accuracy specifications from manufacturers of metering equipment (e.g., specified accuracy of +/- 2%). A uniform distribution with mean equal to zero is assumed for all three measurement types. This distribution implies that any error value within the stated range has an identical probability of occurring in any measurement. This distribution is more conservative than some other commonly assumed distributions (e.g., normal "bell-shaped" curve) because the outlying values are just as likely to occur as the central values.

Table E-2: Summary of Random Measurement Error Variables

Measurement	Range	Mean	Distribution
Electrical Generation	-0.5% to 0.5%	0%	Uniform
Fuel Consumption	-2% to 2%		
Useful Heat Recovered	-5% to 5%		

Metered Data Unavailable – Generating Sample Data from Performance Distributions

In the case of unmetered projects, the sample data are generated by random assignment from distributions of performance values assumed representative of entire groups of unmetered projects. Because measured performance data are not available for any of these projects, the natural place to look first for performance values is similar metered projects.

Specification of performance distributions for the MCS study involves a degree of judgment in at least two areas. The first is in deciding whether or not metered data available for a stratum are sufficient to provide a realistic indication of the distribution of values likely for the unmetered projects. The second is when

[2] This research primarily involved contacting site hosts to determine the operational status of unmetered systems. More details are provided in Appendix B.

metered data available for a stratum are not sufficient in deciding when and how to incorporate the metered data available for other strata into a performance distribution for the data-insufficient stratum.

Table E-3 shows the groups used to estimate the uncertainty in the California Independent System Operator (CAISO) peak hour impact.

Table E-3: Performance Distributions Developed for the 2014 and 2015 CAISO Peak Hour MCS Analysis

Technology Type	Energy Source	PA
Fuel Cell – Combined Heat and Power	Non-Renewable, Renewable	All
Fuel Cell – Electric Only	All	All
Gas Turbine	Non-Renewable[3]	All
Internal Combustion Engine	Non-Renewable, Renewable	All
Microturbine	Non Renewable, Renewable	All
Wind	All	All

Table E-4 shows the groups used to estimate the uncertainty in the yearly energy production. Internal combustion engines, gas turbines, and microturbines are grouped together for the uncertainty analysis of the annual energy production because of the small number of systems within each technology group for which data were available for 90% of each month in the year.

Table E-4: Performance Distributions Developed for the 2014 and 2015 Annual Energy Production MCS Analysis

Technology Type	Energy Source	PA
Fuel Cell – Combined Heat and Power	All	All
Fuel Cell – Electric Only	All	All
Gas Turbine	All	All
Internal Combustion Engine / Microturbine	Non-Renewable, Renewable	All
Pressure Reduction Turbine	All	All
Wind	All	All

Performance distributions were developed for each of the groups in Table E-3 and Table E-4 based on metered data and engineering judgment. In the MCS, a capacity factor is randomly assigned from the performance distribution and sample values are calculated as the product of the capacity factor and system size. All of these performance distributions are shown in Figure E-1 through Figure E-19.

[3] There are no renewable fueled gas turbines in the SGIP as of December 31, 2015

Performance Distributions for Coincident Peak Impacts

Performance distributions used to generate sample data for coincident peak demand impacts are shown in Figure E-1 through Figure E-10. Distributions for unknown operational status are shown in red. Distributions for online operational status are shown in yellow. Operational status online distributions are identical to offline distributions but with no probability at zero capacity factor. Distributions developed for 2015 are shown here as representative; however, a separate set of distributions was used for 2014.

Figure E-1: MCS Distribution-CHP Fuel Cell Coincident Peak Output (Non-Renewable Fuel)

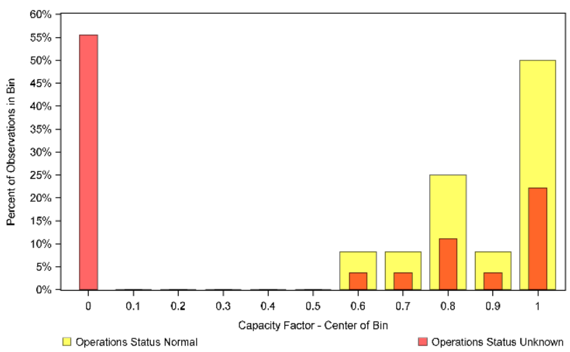


Figure E-2: MCS Distribution-CHP Fuel Cell Coincident Peak Output (Renewable Fuel)

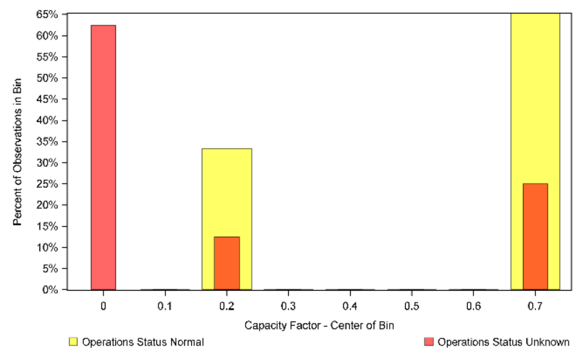


Figure E-3: MCS Distribution-Electric-only Fuel Cell Coincident Peak Output (All Fuel)

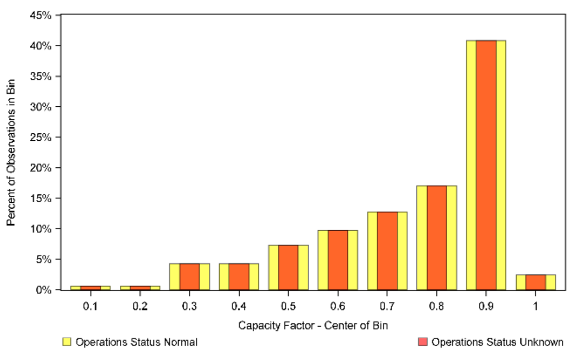


Figure E-4: MCS Distribution-Gas Turbine Coincident Peak Output (Non-Renewable Fuel)

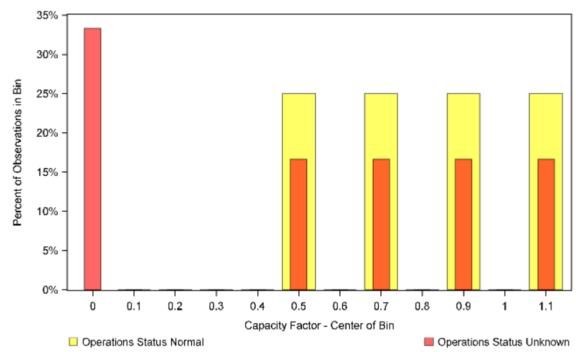


Figure E-5: MCS Distribution-Internal Combustion Engine Coincident Peak Output (Non-Renewable Fuel)

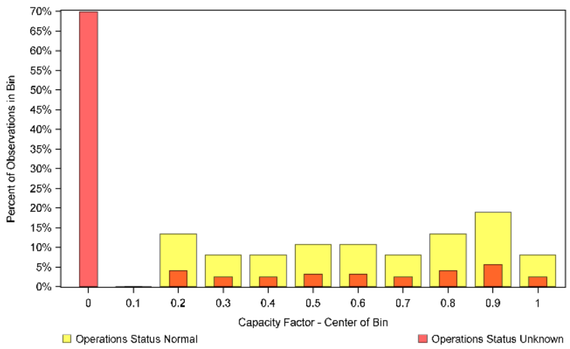


Figure E-6: MCS Distribution-Internal Combustion Engine Coincident Peak Output (Renewable Fuel)

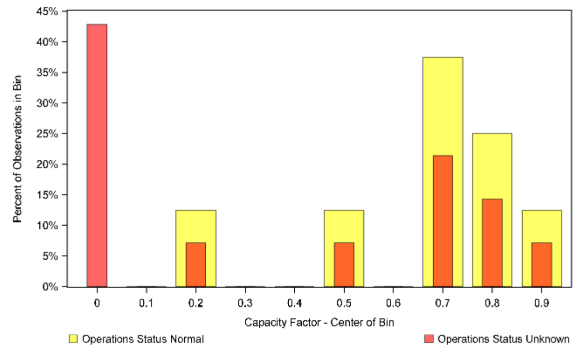


Figure E-7: MCS Distribution-Microturbine Coincident Peak Output (Non-Renewable Fuel)

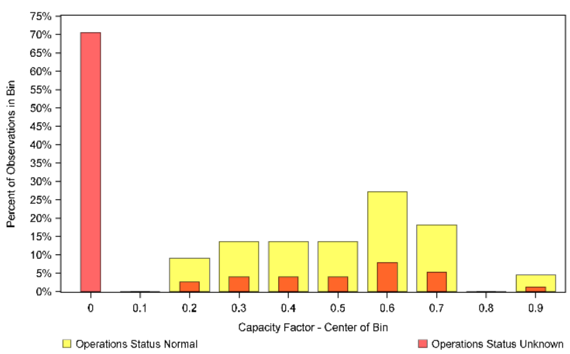


Figure E-8: MCS Distribution-Microturbine Coincident Peak Output (Renewable Fuel)

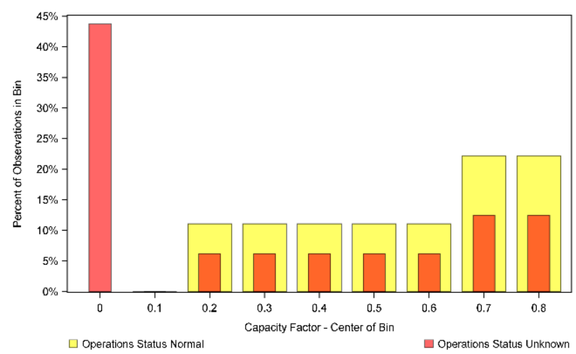


Figure E- 9: MCS Distribution – PRT Coincident Peak Output

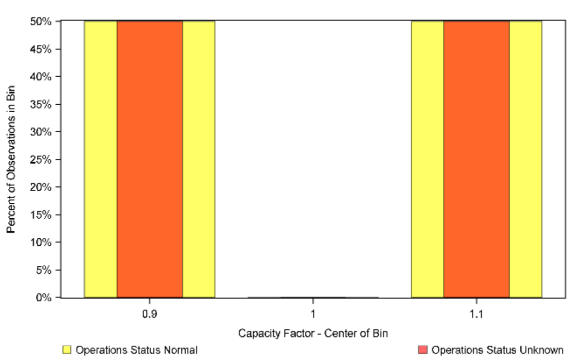
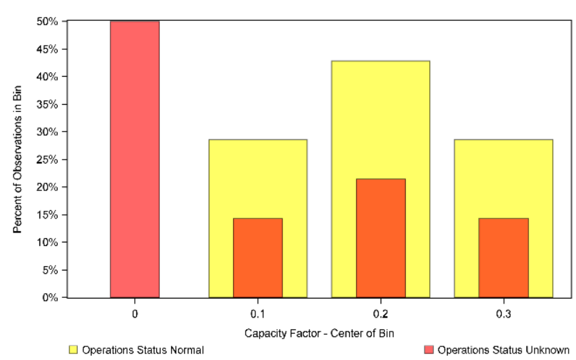


Figure E-10: MCS Distribution-Wind Coincident Peak Output



Performance Distributions for Energy Impacts

Performance distributions used to generate sample data for annual energy impacts are shown in Figure E-10 through Figure E-17. A negative capacity factor indicates energy consumption from the grid to the distributed generator. A capacity factor greater than one indicates generation that exceeds rebated capacity.

Figure E-11: MCS Distribution-Engine/Combustion Turbine (Non-Renewable) Energy Production (Capacity Factor)

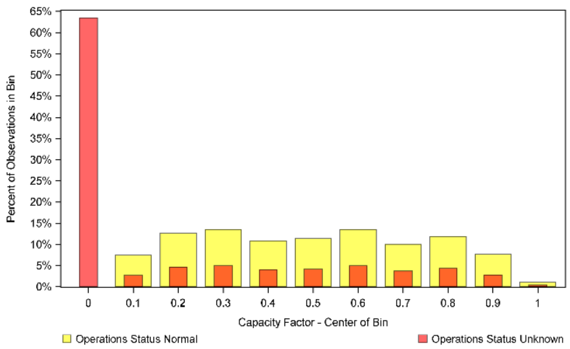


Figure E-12: MCS Distribution-Engine/Combustion Turbine (Renewable) Energy Production (Capacity Factor)

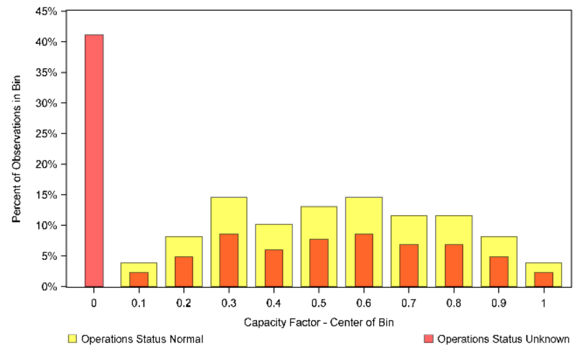


Figure E-13: MCS Distribution-CHP Fuel Cell (All Fuel) Energy Production (Capacity Factor)

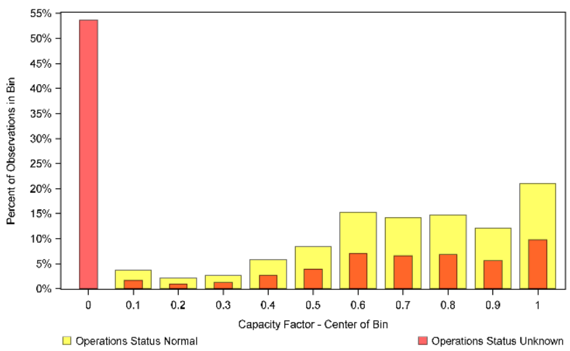


Figure E-14: MCS Distribution-Electric-only Fuel Cell (All Fuel) Energy Production (Capacity Factor)

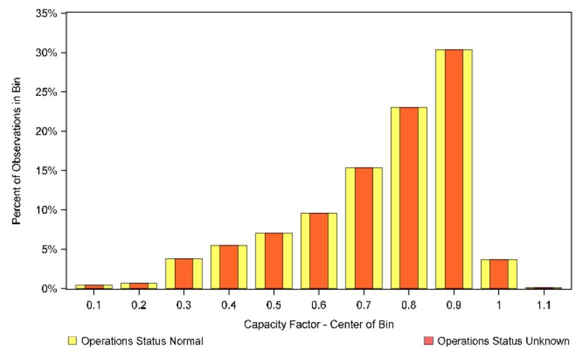


Figure E- 15: MCS Distribution – Gas Turbine (Non-Renewable) Energy Production (Capacity Factor)

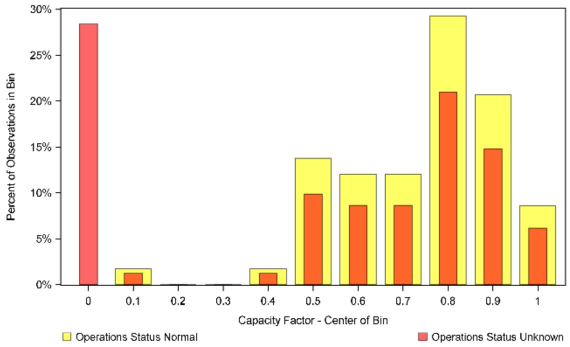


Figure E- 16: MCS Distribution – Pressure Reduction Turbine (No Fuel) Energy Production (Capacity Factor)

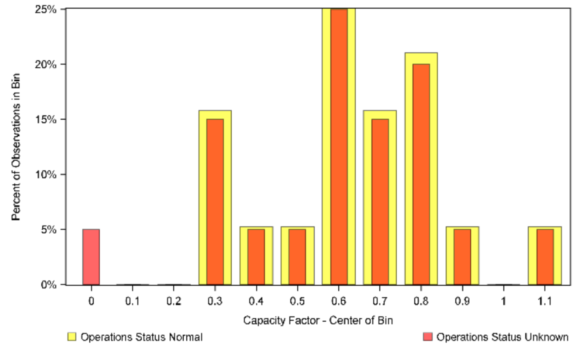


Figure E-17: MCS Distribution-Wind Energy Production (Capacity Factor)

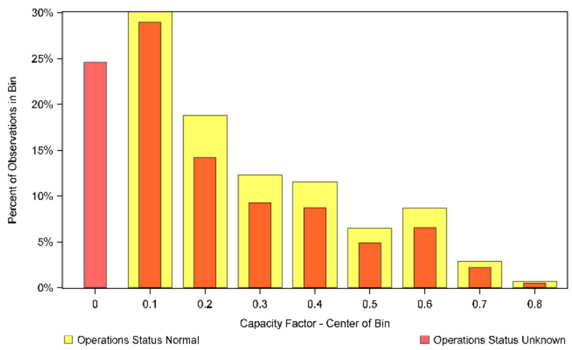


Figure E-18: MCS Distribution-Engine/Combustion Turbine Heat Recovery Rate (MBtu/kWh)

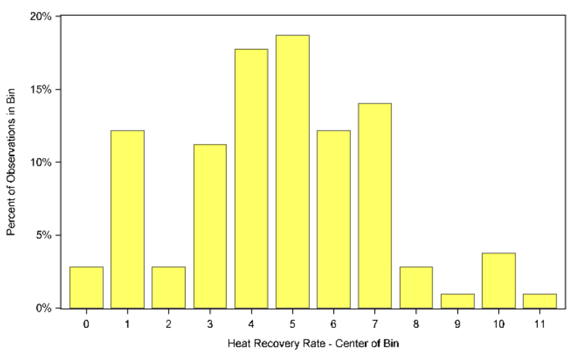


Figure E-19: MCS Distribution-CHP Fuel Cell Heat Recovery Rate (MBtu/kWh)

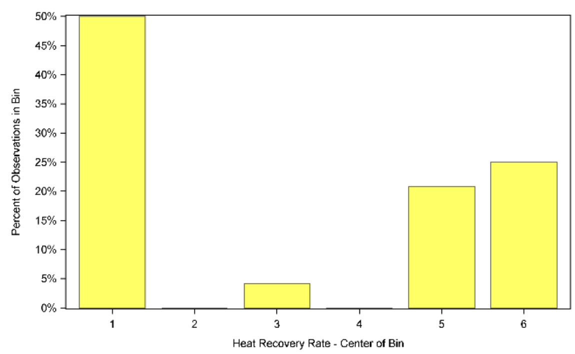
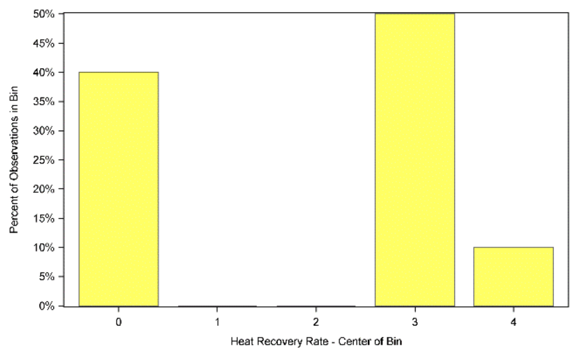


Figure E- 20: MCS Distribution – Gas Turbine Heat Recovery Rate (MBtu/kWh)



Bias

Performance data collected from metered projects were used to estimate program impacts attributable to unmetered projects. If the metered projects are not representative of the unmetered projects, then those estimates will include systematic errors called bias. Potential sources of bias of principal concern for this study include:

Planned Data Collection Disproportionally Favors Dissimilar Groups

Useful heat recovery metering is typically installed on projects that are still under their contract with the SGIP. If the actual useful heat recovery performance of older projects differs systematically from newer metered projects then estimates calculated for older projects will be biased. A similar situation can occur when actual performance differs substantially from performance data assumptions underlying data collection plans.

Actual Data Collection Allocations Deviate from Planned Data Collection Allocations

In program impacts evaluation studies, actual data collection almost invariably deviates somewhat from planned data collection. If the deviation is systematic rather than random then estimates calculated from unmetered projects may be biased. For example, metered data for a number of fuel cell projects are received from their hosts or the fuel cell manufacturer. The result is a metered dataset that may contain a disproportionate quantity of data received from program participants who operate their own metering. This metered dataset is used to calculate impacts for unmetered sites. If the actual performance of the unmetered projects differs systematically from that of the projects metered by participants, then estimates calculated for the unmetered projects will be biased.

Actual Data Collection Quantities Deviate from Planned Data Collection Quantities

For example, plans called for collection of electrical generation data from all renewable fuel use projects; however, data were actually collected only from a small portion of completed renewable fuel use projects.

Treatment of Bias

In the MCS analysis, bias is accounted for during development of performance distributions assumed for unmetered projects. If the metered sample is thought to be biased, then engineering judgment dictates specification of a relatively "more spread out" performance distribution. Bias is accounted for, but the accounting does not involve adjustment of point estimates of program impacts. If engineering judgment dictates an accounting for bias, then the performance distribution assumed for the MCS analysis has a higher standard deviation. The result is a larger confidence interval about the reported point estimate. If there is good reason to believe that bias could be substantial, the confidence interval reported for the point estimate will be larger.

To this point, the discussion of bias has been limited to sampling bias. More generally, bias can also be the result of instrumentation yielding measurements that are not representative of the actual parameters being monitored. Due to the wide variety of instrumentation types and data providers involved with this evaluation, it is not possible to say one way or the other whether or not instrumentation bias contributes to error in impacts reported for either metered or unmetered projects. Due to the relative magnitudes involved, instrumentation bias – if it exists – accounts for an insignificant portion of total bias contained in point estimates of program impacts.

It is important to note that possible sampling bias affects only impacts estimates calculated for unmetered projects. The relative importance of this varies with metering rate. For example, where the metering rate is 90 percent, a 20 percent sampling bias will yield an error of only two percent in total (metered + unmetered) program impacts. All else equal, higher metering rates reduce the impact of sampling bias on estimates of total program impacts.

Calculate the Quantities of Interest for Each Sample

After each simulation run, the resulting sample data for individual projects are summed to the program level and the result is saved. The quantities of interest were defined previously:

- Program Total Annual Electrical Energy Impacts
- Program Total Coincident Peak Electrical Demand Impacts

Analyze Accumulated Quantities of Interest

The pools of accumulated MCS analysis results are analyzed to yield summary information about their central tendency and variability. Mean values are calculated and the variability exhibited by the values for the many runs is examined to determine confidence levels (under the constraint of relative precision), or to determine confidence intervals (under the constraint of constant confidence level).

E.5 2014 Results

This section presents the confidence levels in the energy and peak demand impacts results and the precision and confidence intervals associated with those confidence levels during 2014. In cases where an accuracy level of 90 percent confidence and 10 percent precision (i.e., 90/10) was not achieved, the reported precision values and confidence intervals are based on a 70 percent confidence level. Results are shown for metered, estimated, and combined impacts.

Table E-5: Uncertainty Analysis Results for Annual Energy Impact Results by Technology Type and Basis (2014)

Technology Type/ Basis	Confidence Level	Precision	Confidence Interval
Fuel Cell - Combined Heat & Power	**90%**	**3.04%**	**0.428 to 0.455**
Metered	90%	0.04%	0.456 to 0.456
Estimated	70%	9.19%	0.352 to 0.423
Fuel Cell - Electric Only	**90%**	**0.28%**	**0.698 to 0.702**
Metered	90%	0.01%	0.705 to 0.705
Estimated	90%	5.94%	0.573 to 0.645
Gas Turbine	**90%**	**2.84%**	**0.730 to 0.772**
Metered	90%	0.06%	0.747 to 0.748
Estimated	70%	13.92%	0.672 to 0.889
Internal Combustion Engine	**90%**	**3.75%**	**0.184 to 0.198**
Metered	90%	0.02%	0.171 to 0.171
Estimated	90%	9.00%	0.207 to 0.248
Microturbine	**90%**	**3.15%**	**0.211 to 0.224**
Metered	90%	0.04%	0.220 to 0.221
Estimated	70%	11.63%	0.180 to 0.227
Pressure Reduction Turbine	**90%**	**0.14%**	**0.689 to 0.691**
Metered	90%	0.14%	0.689 to 0.691
Estimated	--	--	--
Wind	**90%**	**7.89%**	**0.222 to 0.260**
Metered	90%	0.07%	0.243 to 0.244
Estimated	70%	14.02%	0.203 to 0.269

Table E-6: Uncertainty Analysis Results for Annual Energy Impact Results by Technology Type, Energy Source, and Basis (2014)

Technology Type & Energy Source / Basis	Confidence Level	Precision	Confidence Interval
Fuel Cell - Combined Heat & Power-N	**90%**	**3.92%**	**0.437 to 0.473**
Metered	90%	0.05%	0.476 to 0.477
Estimated	70%	10.68%	0.345 to 0.427
Fuel Cell - Combined Heat & Power-R	**90%**	**4.36%**	**0.398 to 0.435**
Metered	90%	0.07%	0.422 to 0.422
Estimated	70%	16.33%	0.326 to 0.454
Fuel Cell - Electric Only	**90%**	**0.28%**	**0.698 to 0.702**
Metered	90%	0.01%	0.705 to 0.705
Estimated	90%	5.94%	0.573 to 0.645
Gas Turbine-N	**90%**	**2.84%**	**0.730 to 0.772**
Metered	90%	0.06%	0.747 to 0.748
Estimated	70%	13.92%	0.672 to 0.889
Internal Combustion Engine-N	**90%**	**4.08%**	**0.176 to 0.191**
Metered	90%	0.03%	0.163 to 0.163
Estimated	90%	9.91%	0.203 to 0.247
Internal Combustion Engine-R	**90%**	**8.26%**	**0.228 to 0.270**
Metered	90%	0.06%	0.250 to 0.250
Estimated	70%	11.40%	0.220 to 0.277
Microturbine-N	**90%**	**2.99%**	**0.228 to 0.242**
Metered	90%	0.04%	0.244 to 0.244
Estimated	70%	15.30%	0.159 to 0.216
Microturbine-R	**70%**	**8.01%**	**0.143 to 0.167**
Metered	90%	0.07%	0.126 to 0.126
Estimated	70%	19.79%	0.189 to 0.282
Pressure Reduction Turbine	**90%**	**0.14%**	**0.689 to 0.691**
Metered	90%	0.14%	0.689 to 0.691
Estimated	--	--	--
Wind	**90%**	**7.89%**	**0.222 to 0.260**
Metered	90%	0.07%	0.243 to 0.244
Estimated	70%	14.02%	0.203 to 0.269

Table E-7: Uncertainty Analysis for CSE Annual Energy Impact (2014)

Technology Type/ Basis	Confidence Level	Precision	Confidence Interval
Fuel Cell - Combined Heat & Power	**90%**	**0.72%**	**0.537 to 0.544**
Metered	90%	0.08%	0.543 to 0.544
Estimated	70%	31.67%	0.261 to 0.504
Fuel Cell - Electric Only	**90%**	**2.33%**	**0.700 to 0.734**
Metered	90%	0.05%	0.729 to 0.730
Estimated	90%	9.89%	0.611 to 0.745
Gas Turbine	**90%**	**0.10%**	**0.800 to 0.801**
Metered	90%	0.10%	0.800 to 0.801
Internal Combustion Engine	**90%**	**4.25%**	**0.055 to 0.059**
Metered	90%	0.12%	0.054 to 0.054
Estimated	70%	33.57%	0.124 to 0.250
Microturbine	**90%**	**1.88%**	**0.093 to 0.096**
Metered	90%	0.09%	0.094 to 0.094
Estimated	70%	59.46%	0.076 to 0.301
Pressure Reduction Turbine	**90%**	**0.14%**	**0.689 to 0.691**
Metered	90%	0.14%	0.689 to 0.691
Wind	**90%**	**0.29%**	**0.421 to 0.424**
Metered	90%	0.29%	0.421 to 0.424

Table E-8: Uncertainty Analysis Results for PG&E Annual Energy Impact (2014)

Technology Type / Basis	Confidence Level	Precision	Confidence Interval
Fuel Cell - Combined Heat & Power	**90%**	**3.72%**	**0.433 to 0.466**
Metered	90%	0.06%	0.462 to 0.462
Estimated	70%	16.18%	0.327 to 0.454
Fuel Cell - Electric Only	**90%**	**0.21%**	**0.675 to 0.678**
Metered	90%	0.02%	0.680 to 0.681
Estimated	70%	6.95%	0.488 to 0.561
Gas Turbine	**90%**	**6.25%**	**0.334 to 0.379**
Metered	90%	0.25%	0.023 to 0.024
Estimated	90%	6.53%	0.900 to 1.026
Internal Combustion Engine	**90%**	**7.50%**	**0.172 to 0.200**
Metered	90%	0.03%	0.158 to 0.158
Estimated	70%	8.73%	0.202 to 0.241
Microturbine	**90%**	**3.99%**	**0.277 to 0.299**
Metered	90%	0.04%	0.306 to 0.306
Estimated	70%	19.17%	0.163 to 0.241
Wind	**70%**	**12.10%**	**0.190 to 0.243**
Metered	90%	0.09%	0.186 to 0.187
Estimated	70%	18.50%	0.193 to 0.280

Table E-9: Uncertainty Analysis Results for SCE Annual Energy Impact (2014)

Technology Type / Basis	Confidence Level	Precision	Confidence Interval
Fuel Cell - Combined Heat & Power	**90%**	**7.24%**	**0.409 to 0.473**
Metered	90%	0.07%	0.465 to 0.466
Estimated	70%	16.77%	0.322 to 0.451
Fuel Cell - Electric Only	**90%**	**0.80%**	**0.701 to 0.713**
Metered	90%	0.03%	0.715 to 0.716
Estimated	70%	6.46%	0.586 to 0.667
Internal Combustion Engine	**90%**	**6.56%**	**0.197 to 0.225**
Metered	90%	0.04%	0.189 to 0.189
Estimated	70%	9.14%	0.227 to 0.273
Microturbine	**70%**	**10.21%**	**0.105 to 0.129**
Metered	90%	0.09%	0.076 to 0.076
Estimated	70%	18.65%	0.175 to 0.256
Wind	**90%**	**6.35%**	**0.236 to 0.268**
Metered	90%	0.08%	0.256 to 0.256
Estimated	70%	22.03%	0.182 to 0.285

Table E-10: Uncertainty Analysis Results for SCG Annual Energy Impact (2014)

Technology Type / Basis	Confidence Level	Precision	Confidence Interval
Fuel Cell - Combined Heat & Power	**70%**	**5.89%**	**0.332 to 0.374**
Metered	90%	0.11%	0.331 to 0.332
Estimated	70%	14.25%	0.334 to 0.445
Fuel Cell - Electric Only	**90%**	**0.04%**	**0.747 to 0.747**
Metered	90%	0.03%	0.753 to 0.753
Estimated	70%	18.52%	0.036 to 0.053
Gas Turbine	**90%**	**4.53%**	**0.781 to 0.855**
Metered	90%	0.07%	0.843 to 0.844
Estimated	70%	25.69%	0.498 to 0.843
Internal Combustion Engine	**90%**	**5.13%**	**0.202 to 0.224**
Metered	90%	0.04%	0.208 to 0.208
Estimated	70%	9.86%	0.202 to 0.247
Microturbine	**90%**	**3.07%**	**0.222 to 0.236**
Metered	90%	0.08%	0.236 to 0.236
Estimated	70%	20.99%	0.141 to 0.215

Table E-11: Uncertainty Analysis Results for Peak Demand Impact (2014)

Technology Type / Basis	Confidence Level	Precision	Confidence Interval
Fuel Cell - Combined Heat & Power	**70%**	**9.25%**	**0.365 to 0.439**
Metered	90%	0.16%	0.426 to 0.428
Estimated	70%	43.05%	0.188 to 0.472
Fuel Cell - Electric Only	**90%**	**0.91%**	**0.676 to 0.689**
Metered	90%	0.05%	0.683 to 0.684
Estimated	70%	12.78%	0.600 to 0.776
Gas Turbine	**90%**	**8.45%**	**0.762 to 0.903**
Metered	90%	0.22%	0.859 to 0.863
Estimated	70%	58.28%	0.260 to 0.987
Internal Combustion Engine	**70%**	**7.07%**	**0.230 to 0.265**
Metered	90%	0.09%	0.235 to 0.235
Estimated	70%	17.36%	0.221 to 0.314
Microturbine	**70%**	**8.48%**	**0.196 to 0.232**
Metered	90%	0.11%	0.215 to 0.216
Estimated	70%	41.45%	0.121 to 0.292
Pressure Reduction Turbine	**90%**	**0.45%**	**0.982 to 0.990**
Metered	90%	0.45%	0.982 to 0.990
Wind	**70%**	**24.60%**	**0.142 to 0.235**
Metered	90%	0.24%	0.164 to 0.165
Estimated	70%	52.76%	0.107 to 0.345

Table E-12: Uncertainty Analysis Results for Peak Demand Impact Results by Technology Type, Energy Source, and Basis for CSE (2014)

Technology Type & Energy Source / Basis	Confidence Level	Precision	Confidence Interval
Fuel Cell - Combined Heat & Power-N	**90%**	**0.90%**	**0.550 to 0.560**
Metered	90%	0.32%	0.556 to 0.560
Estimated	70%	64.94%	0.123 to 0.577
Fuel Cell - Combined Heat & Power-R	**--**	**--**	**--**
Metered	--	--	--
Fuel Cell - Electric Only	**90%**	**8.34%**	**0.637 to 0.753**
Metered	90%	0.18%	0.716 to 0.718
Estimated	70%	18.52%	0.550 to 0.800
Gas Turbine-N	**90%**	**0.35%**	**1.013 to 1.020**
Metered	90%	0.35%	1.013 to 1.020
Internal Combustion Engine-N	**70%**	**100.0%**	**0.000 to 0.014**
Metered	90%	--	0.000 to 0.000
Estimated	70%	100.0%	0.000 to 0.450
Internal Combustion Engine-R	**90%**	**0.44%**	**0.816 to 0.823**
Metered	90%	0.44%	0.816 to 0.823
Microturbine-N	**70%**	**8.64%**	**0.086 to 0.102**
Metered	90%	0.34%	0.088 to 0.088
Estimated	70%	100.0%	0.000 to 0.600
Microturbine-R	**90%**	**0.44%**	**0.106 to 0.107**
Metered	90%	0.44%	0.106 to 0.107
Pressure Reduction Turbine	**90%**	**0.45%**	**0.982 to 0.990**
Metered	90%	0.45%	0.982 to 0.990

Table E-13: Uncertainty Analysis Results for Peak Demand Impact Results by Technology Type, Energy Source, and Basis for PG&E (2014)

Technology Type & Energy Source / Basis	Confidence Level	Precision	Confidence Interval
Fuel Cell - Combined Heat & Power-N	**70%**	**24.54%**	**0.260 to 0.430**
Metered	90%	0.35%	0.353 to 0.356
Estimated	70%	84.62%	0.050 to 0.599
Fuel Cell - Combined Heat & Power-R	**90%**	**0.34%**	**0.719 to 0.724**
Metered	90%	0.34%	0.719 to 0.724
Fuel Cell - Electric Only	**90%**	**0.65%**	**0.668 to 0.677**
Metered	90%	0.07%	0.673 to 0.674
Estimated	70%	15.46%	0.586 to 0.800
Gas Turbine-N	**70%**	**14.29%**	**0.319 to 0.425**
Metered	90%	--	0.000 to 0.000
Estimated	70%	14.29%	0.900 to 1.200
Internal Combustion Engine-N	**70%**	**14.59%**	**0.222 to 0.298**
Metered	90%	0.14%	0.266 to 0.266
Estimated	70%	32.65%	0.170 to 0.335
Internal Combustion Engine-R	**70%**	**36.78%**	**0.126 to 0.273**
Metered	90%	0.31%	0.127 to 0.127
Estimated	70%	53.97%	0.126 to 0.421
Microturbine-N	**70%**	**9.70%**	**0.296 to 0.359**
Metered	90%	0.17%	0.351 to 0.352
Estimated	70%	79.44%	0.045 to 0.394
Microturbine-R	**70%**	**25.21%**	**0.145 to 0.243**
Metered	90%	0.29%	0.185 to 0.186
Estimated	70%	72.23%	0.059 to 0.369
Wind	**70%**	**29.12%**	**0.240 to 0.437**
Metered	90%	0.31%	0.530 to 0.533
Estimated	70%	67.64%	0.074 to 0.382

Table E-14: Uncertainty Analysis Results for Peak Demand Impact Results by Technology Type, Energy Source, and Basis for SCE (2014)

Technology Type & Energy Source / Basis	Confidence Level	Precision	Confidence Interval
Fuel Cell - Combined Heat & Power-N	**70%**	**11.13%**	**0.477 to 0.597**
Metered	90%	0.35%	0.542 to 0.546
Estimated	70%	100.0%	0.000 to 0.976
Fuel Cell - Combined Heat & Power-R	**70%**	**48.38%**	**0.175 to 0.502**
Metered	90%	0.45%	0.360 to 0.363
Estimated	70%	85.71%	0.046 to 0.600
Fuel Cell - Electric Only	**90%**	**2.88%**	**0.640 to 0.678**
Metered	90%	0.09%	0.663 to 0.664
Estimated	70%	23.08%	0.500 to 0.800
Internal Combustion Engine-N	**70%**	**14.66%**	**0.220 to 0.295**
Metered	90%	0.19%	0.217 to 0.218
Estimated	70%	29.10%	0.223 to 0.406
Internal Combustion Engine-R	**70%**	**19.69%**	**0.177 to 0.263**
Metered	90%	0.34%	0.199 to 0.200
Estimated	70%	61.53%	0.108 to 0.455
Microturbine-N	**70%**	**31.22%**	**0.103 to 0.197**
Metered	90%	0.44%	0.126 to 0.128
Estimated	70%	88.33%	0.027 to 0.428
Microturbine-R	**70%**	**57.39%**	**0.066 to 0.243**
Metered	90%	0.46%	0.102 to 0.103
Estimated	70%	100.0%	0.000 to 0.491
Wind	**70%**	**45.29%**	**0.059 to 0.156**
Metered	90%	0.35%	0.063 to 0.064
Estimated	70%	81.84%	0.044 to 0.443

Table E-15: Uncertainty Analysis Results for Peak Demand Impact Results by Technology Type, Energy Source, and Basis for SCG (2014)

Technology Type & Energy Source / Basis	Confidence Level	Precision	Confidence Interval
Fuel Cell - Combined Heat & Power-N	**70%**	**71.50%**	**0.098 to 0.588**
Metered	90%	0.46%	0.436 to 0.439
Estimated	70%	96.88%	0.010 to 0.627
Fuel Cell - Combined Heat & Power-R	**70%**	**47.17%**	**0.055 to 0.153**
Metered	90%	0.46%	0.062 to 0.062
Estimated	70%	100.0%	0.000 to 0.900
Fuel Cell - Electric Only	**90%**	**0.11%**	**0.723 to 0.725**
Metered	90%	0.11%	0.723 to 0.725
Gas Turbine-N	**70%**	**11.37%**	**0.731 to 0.919**
Metered	90%	0.28%	0.918 to 0.924
Estimated	70%	100.0%	0.000 to 0.900
Internal Combustion Engine-N	**70%**	**10.33%**	**0.254 to 0.312**
Metered	90%	0.15%	0.293 to 0.294
Estimated	70%	37.17%	0.163 to 0.356
Internal Combustion Engine-R	**70%**	**75.83%**	**0.062 to 0.453**
Estimated	70%	75.83%	0.062 to 0.453
Microturbine-N	**70%**	**21.74%**	**0.138 to 0.215**
Metered	90%	0.30%	0.163 to 0.164
Estimated	70%	84.83%	0.035 to 0.428

E.6 2015 Results

This section presents the confidence levels in the energy and peak demand impacts results and the precision and confidence intervals associated with those confidence levels during 2015. In cases where an accuracy level of 90 percent confidence and 10 percent precision (i.e., 90/10) was not achieved, the reported precision values and confidence intervals are based on a 70 percent confidence level. Results are shown for metered, estimated, and combined impacts.

Table E-16: Uncertainty Analysis Results for Annual Energy Impact Results by Technology Type and Basis (2015)

Technology Type/ Basis	Confidence Level	Precision	Confidence Interval
Fuel Cell - Combined Heat & Power	**90%**	**3.76%**	**0.362 to 0.391**
Metered	90%	0.04%	0.400 to 0.401
Estimated	70%	8.90%	0.290 to 0.347
Fuel Cell - Electric Only	**90%**	**0.52%**	**0.708 to 0.715**
Metered	90%	0.01%	0.707 to 0.707
Estimated	90%	2.30%	0.709 to 0.743
Gas Turbine	**90%**	**4.88%**	**0.599 to 0.660**
Metered	90%	0.06%	0.663 to 0.664
Estimated	70%	10.83%	0.493 to 0.613
Internal Combustion Engine	**90%**	**3.80%**	**0.192 to 0.207**
Metered	90%	0.03%	0.177 to 0.177
Estimated	90%	7.93%	0.212 to 0.249
Microturbine	**90%**	**4.80%**	**0.217 to 0.239**
Metered	90%	0.03%	0.234 to 0.234
Estimated	70%	12.62%	0.183 to 0.236
Pressure Reduction Turbine	**90%**	**0.11%**	**0.608 to 0.609**
Metered	90%	0.11%	0.608 to 0.609
Wind	**90%**	**3.89%**	**0.183 to 0.198**
Metered	90%	0.06%	0.237 to 0.237
Estimated	70%	13.05%	0.089 to 0.116

Table E-17: Uncertainty Analysis Results for Annual Energy Impact Results by Technology Type, Energy Source, and Basis (2015)

Technology Type & Energy Source / Basis	Confidence Level	Precision	Confidence Interval
Fuel Cell - Combined Heat & Power-N	**90%**	**4.31%**	**0.396 to 0.432**
Metered	90%	0.05%	0.454 to 0.454
Estimated	70%	11.08%	0.281 to 0.351
Fuel Cell - Combined Heat & Power-R	**90%**	**7.89%**	**0.278 to 0.326**
Metered	90%	0.09%	0.294 to 0.294
Estimated	70%	15.16%	0.272 to 0.370
Fuel Cell - Electric Only	**90%**	**0.52%**	**0.708 to 0.715**
Metered	90%	0.01%	0.707 to 0.707
Estimated	90%	2.30%	0.709 to 0.743
Gas Turbine-N	**90%**	**4.88%**	**0.599 to 0.660**
Metered	90%	0.06%	0.663 to 0.664
Estimated	70%	10.83%	0.493 to 0.613
Internal Combustion Engine-N	**90%**	**4.30%**	**0.175 to 0.191**
Metered	90%	0.03%	0.164 to 0.164
Estimated	90%	9.52%	0.192 to 0.232
Internal Combustion Engine-R	**90%**	**7.66%**	**0.278 to 0.324**
Metered	90%	0.05%	0.286 to 0.287
Estimated	70%	8.38%	0.285 to 0.338
Microturbine-N	**90%**	**5.70%**	**0.216 to 0.242**
Metered	90%	0.04%	0.245 to 0.245
Estimated	70%	17.60%	0.147 to 0.210
Microturbine-R	**90%**	**9.10%**	**0.204 to 0.245**
Metered	90%	0.06%	0.187 to 0.187
Estimated	70%	14.93%	0.268 to 0.363
Pressure Reduction Turbine	**90%**	**0.11%**	**0.608 to 0.609**
Metered	90%	0.11%	0.608 to 0.609
Wind	**90%**	**3.89%**	**0.183 to 0.198**
Metered	90%	0.06%	0.237 to 0.237
Estimated	70%	13.05%	0.089 to 0.116

Table E-18: Uncertainty Analysis for CSE Annual Energy Impact (2015)

Technology Type/ Basis	Confidence Level	Precision	Confidence Interval
Fuel Cell - Combined Heat & Power	**90%**	**1.07%**	**0.513 to 0.524**
Metered	90%	0.08%	0.522 to 0.522
Estimated	70%	53.51%	0.167 to 0.550
Fuel Cell - Electric Only	**90%**	**2.51%**	**0.619 to 0.651**
Metered	90%	0.04%	0.613 to 0.614
Estimated	70%	6.90%	0.683 to 0.785
Gas Turbine	**90%**	**5.23%**	**0.768 to 0.853**
Metered	90%	0.08%	0.847 to 0.848
Estimated	70%	37.03%	0.345 to 0.751
Internal Combustion Engine	**70%**	**7.74%**	**0.072 to 0.085**
Metered	90%	0.10%	0.067 to 0.067
Estimated	70%	33.25%	0.121 to 0.242
Microturbine	**90%**	**3.68%**	**0.052 to 0.056**
Metered	90%	0.10%	0.052 to 0.052
Estimated	70%	43.61%	0.102 to 0.258
Pressure Reduction Turbine	**90%**	**0.14%**	**0.670 to 0.671**
Metered	90%	0.14%	0.670 to 0.671
Wind	**90%**	**0.14%**	**0.443 to 0.445**
Metered	90%	0.14%	0.443 to 0.445

Table E-19: Uncertainty Analysis Results for PG&E Annual Energy Impact (2015)

Technology Type / Basis	Confidence Level	Precision	Confidence Interval
Fuel Cell - Combined Heat & Power	**90%**	**5.21%**	**0.371 to 0.412**
Metered	90%	0.06%	0.418 to 0.418
Estimated	70%	15.26%	0.267 to 0.362
Fuel Cell - Electric Only	**90%**	**0.80%**	**0.718 to 0.730**
Metered	90%	0.02%	0.722 to 0.722
Estimated	90%	2.93%	0.708 to 0.751
Gas Turbine	**90%**	**6.30%**	**0.402 to 0.456**
Metered	90%	0.14%	0.388 to 0.389
Estimated	70%	18.89%	0.503 to 0.738
Internal Combustion Engine	**90%**	**6.56%**	**0.188 to 0.214**
Metered	90%	0.03%	0.176 to 0.176
Estimated	70%	7.24%	0.212 to 0.245
Microturbine	**90%**	**7.75%**	**0.250 to 0.292**
Metered	90%	0.04%	0.304 to 0.304
Estimated	70%	20.02%	0.158 to 0.238
Pressure Reduction Turbine	**90%**	**0.19%**	**0.532 to 0.534**
Metered	90%	0.19%	0.532 to 0.534
Wind	**90%**	**7.14%**	**0.170 to 0.196**
Metered	90%	0.07%	0.261 to 0.262
Estimated	70%	16.98%	0.085 to 0.120

Table E-20: Uncertainty Analysis Results for SCE Annual Energy Impact (2015)

Technology Type / Basis	Confidence Level	Precision	Confidence Interval
Fuel Cell - Combined Heat & Power	**70%**	**7.10%**	**0.287 to 0.330**
Metered	90%	0.10%	0.300 to 0.301
Estimated	70%	13.67%	0.273 to 0.360
Fuel Cell - Electric Only	**90%**	**0.87%**	**0.678 to 0.690**
Metered	90%	0.02%	0.684 to 0.684
Estimated	90%	6.52%	0.640 to 0.730
Internal Combustion Engine	**90%**	**7.75%**	**0.202 to 0.236**
Metered	90%	0.05%	0.196 to 0.196
Estimated	70%	9.95%	0.223 to 0.273
Microturbine	**70%**	**8.82%**	**0.143 to 0.170**
Metered	90%	0.07%	0.114 to 0.114
Estimated	70%	17.10%	0.199 to 0.281
Wind	**90%**	**4.61%**	**0.172 to 0.189**
Metered	90%	0.09%	0.206 to 0.206
Estimated	70%	20.23%	0.082 to 0.123

Table E-21: Uncertainty Analysis Results for SCG Annual Energy Impact (2015)

Technology Type / Basis	Confidence Level	Precision	Confidence Interval
Fuel Cell - Combined Heat & Power	**70%**	**7.18%**	**0.269 to 0.311**
Metered	90%	0.12%	0.269 to 0.270
Estimated	70%	15.79%	0.269 to 0.371
Fuel Cell - Electric Only	**90%**	**1.09%**	**0.735 to 0.751**
Metered	90%	0.03%	0.742 to 0.743
Estimated	90%	5.30%	0.704 to 0.783
Gas Turbine	**70%**	**6.46%**	**0.601 to 0.684**
Metered	90%	0.11%	0.766 to 0.767
Estimated	70%	14.25%	0.462 to 0.615
Internal Combustion Engine	**90%**	**5.38%**	**0.198 to 0.220**
Metered	90%	0.05%	0.200 to 0.200
Estimated	70%	8.06%	0.204 to 0.240
Microturbine	**90%**	**2.12%**	**0.257 to 0.268**
Metered	90%	0.07%	0.270 to 0.271
Estimated	70%	17.70%	0.149 to 0.212

Table E-22: Uncertainty Analysis Results for Peak Demand Impact (2015)

Technology Type / Basis	Confidence Level	Precision	Confidence Interval
Fuel Cell - Combined Heat & Power	**70%**	**8.53%**	**0.360 to 0.427**
Metered	90%	0.15%	0.425 to 0.426
Estimated	70%	35.07%	0.207 to 0.431
Fuel Cell - Electric Only	**90%**	**1.66%**	**0.709 to 0.733**
Metered	90%	0.04%	0.716 to 0.717
Estimated	90%	8.29%	0.679 to 0.802
Gas Turbine	**70%**	**14.13%**	**0.536 to 0.713**
Metered	90%	0.24%	0.677 to 0.681
Estimated	70%	38.57%	0.338 to 0.762
Internal Combustion Engine	**70%**	**9.25%**	**0.209 to 0.252**
Metered	90%	0.10%	0.204 to 0.204
Estimated	70%	18.65%	0.216 to 0.316
Microturbine	**70%**	**11.59%**	**0.174 to 0.220**
Metered	90%	0.11%	0.201 to 0.201
Estimated	70%	46.98%	0.099 to 0.275
Pressure Reduction Turbine	**90%**	**0.35%**	**0.983 to 0.990**
Metered	90%	0.35%	0.983 to 0.990
Wind	**70%**	**19.95%**	**0.070 to 0.104**
Metered	90%	0.20%	0.077 to 0.077
Estimated	70%	44.27%	0.057 to 0.148

Table E-23: Uncertainty Analysis Results for Peak Demand Impact Results by Technology Type, Energy Source, and Basis for CSE (2015)

Technology Type & Energy Source / Basis	Confidence Level	Precision	Confidence Interval
Fuel Cell - Combined Heat & Power-N	**90%**	**0.92%**	**0.548 to 0.558**
Metered	90%	0.29%	0.553 to 0.557
Estimated	70%	60.23%	0.155 to 0.623
Fuel Cell - Combined Heat & Power-R	**90%**	**0.45%**	**0.727 to 0.733**
Metered	90%	0.45%	0.727 to 0.733
Fuel Cell - Electric Only	**90%**	**7.89%**	**0.569 to 0.667**
Metered	90%	0.14%	0.620 to 0.622
Estimated	70%	28.57%	0.500 to 0.900
Gas Turbine-N	**70%**	**21.55%**	**0.668 to 1.035**
Metered	90%	0.34%	1.001 to 1.008
Estimated	70%	100.0%	0.000 to 1.100
Internal Combustion Engine-N	**70%**	**29.30%**	**0.067 to 0.123**
Metered	90%	0.45%	0.075 to 0.075
Estimated	70%	100.0%	0.000 to 0.515
Internal Combustion Engine-R	**90%**	**0.45%**	**0.000 to 0.000**
Metered	90%	0.45%	0.000 to 0.000
Microturbine-N	**70%**	**16.99%**	**0.033 to 0.047**
Metered	90%	0.46%	0.034 to 0.034
Estimated	70%	100.0%	0.000 to 0.500
Microturbine-R	**90%**	**0.46%**	**0.102 to 0.103**
Metered	90%	0.46%	0.102 to 0.103
Pressure Reduction Turbine	**90%**	**0.44%**	**0.858 to 0.866**
Metered	90%	0.44%	0.858 to 0.866
Wind	**90%**	**0.45%**	**0.180 to 0.182**
Metered	90%	0.45%	0.180 to 0.182

Table E-24: Uncertainty Analysis Results for Peak Demand Impact Results by Technology Type, Energy Source, and Basis for PG&E (2015)

Technology Type & Energy Source / Basis	Confidence Level	Precision	Confidence Interval
Fuel Cell - Combined Heat & Power-N	**70%**	**13.95%**	**0.389 to 0.515**
Metered	90%	0.25%	0.472 to 0.474
Estimated	70%	55.63%	0.177 to 0.620
Fuel Cell - Combined Heat & Power-R	**70%**	**27.51%**	**0.308 to 0.542**
Metered	90%	0.46%	0.461 to 0.466
Estimated	70%	100.0%	0.000 to 0.700
Fuel Cell - Electric Only	**90%**	**2.43%**	**0.716 to 0.752**
Metered	90%	0.06%	0.733 to 0.734
Estimated	90%	9.78%	0.664 to 0.808
Gas Turbine-N	**90%**	**7.15%**	**0.424 to 0.489**
Metered	90%	0.45%	0.414 to 0.418
Estimated	70%	37.50%	0.500 to 1.100
Internal Combustion Engine-N	**70%**	**17.33%**	**0.178 to 0.253**
Metered	90%	0.14%	0.202 to 0.202
Estimated	70%	35.82%	0.148 to 0.314
Internal Combustion Engine-R	**70%**	**30.54%**	**0.219 to 0.412**
Metered	90%	0.32%	0.210 to 0.211
Estimated	70%	40.91%	0.224 to 0.535
Microturbine-N	**70%**	**23.25%**	**0.168 to 0.270**
Metered	90%	0.18%	0.235 to 0.236
Estimated	70%	89.19%	0.020 to 0.344
Microturbine-R	**70%**	**21.26%**	**0.214 to 0.330**
Metered	90%	0.24%	0.251 to 0.253
Estimated	70%	62.54%	0.120 to 0.521
Pressure Reduction Turbine	**90%**	**0.46%**	**1.095 to 1.105**
Metered	90%	0.46%	1.095 to 1.105
Wind	**70%**	**25.84%**	**0.098 to 0.166**
Metered	90%	0.26%	0.171 to 0.172
Estimated	70%	57.29%	0.044 to 0.163

Table E-25: Uncertainty Analysis Results for Peak Demand Impact Results by Technology Type, Energy Source, and Basis for SCE (2015)

Technology Type & Energy Source / Basis	Confidence Level	Precision	Confidence Interval
Fuel Cell - Combined Heat & Power-N	**70%**	**18.62%**	**0.470 to 0.685**
Metered	90%	0.34%	0.599 to 0.603
Estimated	70%	100.0%	0.000 to 0.991
Fuel Cell - Combined Heat & Power-R	**70%**	**80.77%**	**0.030 to 0.285**
Metered	90%	--	0.000 to 0.000
Estimated	70%	80.77%	0.039 to 0.369
Fuel Cell - Electric Only	**90%**	**2.42%**	**0.689 to 0.723**
Metered	90%	0.08%	0.705 to 0.706
Estimated	70%	15.44%	0.622 to 0.850
Internal Combustion Engine-N	**70%**	**26.51%**	**0.176 to 0.303**
Metered	90%	0.22%	0.201 to 0.202
Estimated	70%	44.67%	0.152 to 0.397
Internal Combustion Engine-R	**70%**	**22.19%**	**0.341 to 0.536**
Metered	90%	0.25%	0.476 to 0.479
Estimated	70%	67.96%	0.120 to 0.630
Microturbine-N	**70%**	**45.80%**	**0.073 to 0.196**
Metered	90%	0.40%	0.113 to 0.114
Estimated	70%	94.34%	0.009 to 0.325
Microturbine-R	**70%**	**41.36%**	**0.144 to 0.348**
Metered	90%	0.34%	0.200 to 0.201
Estimated	70%	85.98%	0.046 to 0.607
Wind	**70%**	**45.93%**	**0.024 to 0.065**
Metered	90%	0.40%	0.025 to 0.025
Estimated	70%	80.48%	0.020 to 0.186

Table E-26: Uncertainty Analysis Results for Peak Demand Impact Results by Technology Type, Energy Source, and Basis for SCG (2015)

Technology Type & Energy Source / Basis	Confidence Level	Precision	Confidence Interval
Fuel Cell - Combined Heat & Power-N	**70%**	**70.41%**	**0.104 to 0.597**
Metered	90%	0.44%	0.435 to 0.439
Estimated	70%	94.72%	0.017 to 0.638
Fuel Cell - Combined Heat & Power-R	**70%**	**33.23%**	**0.077 to 0.153**
Metered	90%	0.45%	0.086 to 0.087
Estimated	70%	100.0%	0.000 to 0.700
Fuel Cell - Electric Only	**90%**	**4.28%**	**0.695 to 0.757**
Metered	90%	0.11%	0.728 to 0.730
Estimated	70%	13.93%	0.639 to 0.846
Gas Turbine-N	**70%**	**33.93%**	**0.382 to 0.774**
Metered	90%	0.44%	0.725 to 0.731
Estimated	70%	50.86%	0.258 to 0.791
Internal Combustion Engine-N	**70%**	**13.94%**	**0.184 to 0.244**
Metered	90%	0.19%	0.207 to 0.208
Estimated	70%	38.45%	0.140 to 0.314
Internal Combustion Engine-R	**70%**	**51.66%**	**0.184 to 0.577**
Estimated	70%	51.66%	0.184 to 0.577
Microturbine-N	**90%**	**7.29%**	**0.202 to 0.234**
Metered	90%	0.25%	0.222 to 0.223
Estimated	70%	79.98%	0.029 to 0.259

E.7 Statistical Precision of Population Coincident Peak and Emissions Estimates

One metric considered during this analysis was statistical precision as a function of confidence levels, where precision is defined as the margin of error of a distribution divided by the mean. This gives a measure of how narrow, as a percentage of the mean, a confidence interval is. In keeping with previous statistical analyses performed when expanding sample statistics to speak for a program's population, the "90/10", "80/20" and "70/30" tests were explored. That is, we looked to see if a distribution showed 10% precision under a 90% confidence interval. If it did not, we looked to see if it showed a 20% precision under an 80% confidence interval. Lastly, if this was not obtained, we checked for 30% precision under a 70% confidence interval. Table E-27 below shows the results of these tests for the various distributions examined.

Table E-27: Summary of Statistical Precision, Population Coincident Peak and Emissions Estimates

Statistic		Data Source							
		PBI, Non-Residential				Non-PBI			
		PG&E	SCE	SDG&E	Total	PG&E	SCE	SDG&E	Total
Coincident Peak Contribution **(see Section 6 for values)**	Top Hour	Failed 70/30	Failed 70/30	N/A	Failed 70/30	Failed 70/30	Failed 70/30	Failed 70/30	Failed 70/30
	Top 1-50 Hours	Failed 70/30	Failed 70/30	N/A	Failed 70/30	Failed 70/30	Failed 70/30	Passed 80/20	Passed 80/20
	Top 51-100 Hours	Passed 70/30	Failed 70/30	N/A	Failed 70/30	Passed 70/30	Passed 70/30	Passed 80/20	Passed 80/20
	Top 101-150 Hours	Failed 70/30	Failed 70/30	N/A	Failed 70/30	Failed 70/30	Failed 70/30	Passed 70/30	Passed 80/20
	Top 151-200 Hours	Failed 70/30	Failed 70/30	N/A	Failed 70/30	Failed 70/30	Failed 70/30	Passed 80/20	Passed 80/20
Emissions **(see Section 7 for values)**		Failed 70/30	Failed 70/30	N/A	Failed 70/30	Passed 80/20	Passed 70/30	Passed 70/30	Passed 90/10

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