2012 SGIP Impact Evaluation and Program Outlook

Submitted to:

PG&E and The SGIP Working Group

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GLOSSARY

Abbreviations & Acronyms

Term	***Definition***
CAISO	California Independent System Operator
CCSE	California Center for Sustainable Energy
CEC	California Energy Commission
CO_2	Carbon Dioxide
CO_2Eq	CO_2 equivalent
CPUC	California Public Utilities Commission
DENO	Date Entered Normal Operation
IOU	Investor-owned Utility
NEM	Net Energy Metering
NOx	NOx refers to nitric oxide (NO) and nitrogen dioxide (NO2).
PA	Program Administrator
PG&E	Pacific Gas and Electric Company
PM-10	Particulate matter (PM) with diameter of 10 micrometers or less.
POU	Publicly-owned Utility
PPA	Power Purchase Agreement
PY	Program Year
SCE	Southern California Edison
SCG	Southern California Gas Company
SDG&E	San Diego Gas and Electric Company
SGIP	Self-Generation Incentive Program

Key Terms

Term	*Definition*
Applicant (as defined for SGIP)	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 the main point of communication between 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 derived from landfills, wastewater treatment facilities, food processing facilities employing digesters and dairy operations employing digesters.
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	The ratio of electrical energy generated to the electrical energy that would be produced by the generating system at full capacity during the same period (e.g., hourly, annually, etc.)
Combined Heat and Power (CHP)	A facility where both electricity and useful heat are produced simultaneously. CHP is sometimes referred to as "cogeneration."
CO_2 Equivalent (CO_2Eq)	When reporting emission impacts from different types of greenhouse gases, total GHG emissions are reported in terms of tons of CO_2 equivalent so that direct comparisons can be made. To calculate the CO_2Eq, the global warming potential of a gas as compared to that of CO_2 is used as the conversion factor (e.g., The global warming potential of CH_4 is 21 times that of CO_2. Thus, to calculate the CO_2Eq of a given amount of CH_4, you multiply that amount by the conversion factor of 21.
Commercial	Commercial entities are defined as non-manufacturing business establishments, including hotels, motels, restaurants, wholesale businesses, retail stores, and for-profit health, social, and educational institutions.
Confidence Interval	A particular kind of interval estimate of a population parameter (such as the mean value) used to indicate the reliability of an 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

Term	*Definition*
	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, the resultant sample estimate will be within ±10 percent of the true value, 90 percent of the time.
Decommissioned (projects)	"Decommissioned" projects are those where the SGIP system has been retired and the equipment removed from the project site.
Date Entered Normal Operation (DENO)	For impact evaluation purposes, DENO is the date at which an SGIP project has completed shakedown or testing phase and the operations reach a level believed to accurately represent long-run average operations. Metered performance data and validation procedures are used in determining DENO.
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 defined as a renewable fuel.
Electrical Conversion Efficiency	The ratio of electrical energy produced to the fuel (lower heat value) energy used.
Flaring (of Biogas)	Within the context of this report, flaring refers to a basis of how biogas is treated for GHG emission accounting purposes. A basis of flaring 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 CO_2.
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 heating value of a fuel is the amount of heat released from combustion of the fuel. The higher heating value is based on bringing all the products of combustion back to the original pre-combustion temperature, and in particular condensing any vapor produced. Units of HHV are typically Btu/lb of fuel.
Lower Heating Value (LHV)	The lower heating value of a fuel is a measurement of the heat released from combustion of the fuel assuming that the water produced from the combustion process remains in a vapor state at the end of combustion.

Term	*Definition*
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 demand.
Marginal Heat Rate	Heat rate is a measurement used to calculate how efficiently a generator uses heat energy (or its efficiency in converting fuel to electricity). It is expressed as the number of Btus of heat required to produce a kilowatt-hour of energy. The marginal heat rate is the amount of source energy that is saved as a result of a change in generation.
Off line projects	"Off line" projects are those where the annual capacity factor is less than 0.05. Off line projects are considered to be primarily disconnected to the grid and therefore are not providing power to the grid.
On line Projects	"On line" projects are those where the annual capacity factor is equal to or greater than 0.05. On line projects are considered connected to the grid and providing power to the grid.
On site Biogas	On site biogas refers to biogas projects where the biogas source is located directly at the host site where the SGIP system is located.
Prime Mover	A "prime mover" imparts power or motion to another device such as a turbine that turns a generator, or an engine that drives an electrical generator. Examples of prime movers in the SGIP include gas turbines, IC engines, wind turbines, fuel cells, etc.
Rebated Capacity	The capacity rating associated with the rebate (incentive) provided to the program participant. The rebated capacity may be lower than the typical "nameplate" rating of the technology.
Recovered Waste Heat	Recovered waste heat refers to the amount of waste heat delivered at the back end of a CHP prime mover and is recoverable for possible end use. However, if heat load at the host site is lower than the amount of recoverable waste heat, the useful waste heat will be lower than the recoverable waste heat.
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	This is the manufacturer rated nominal size that approximates the generator's highest capacity to generate electricity under specified conditions.

Term	*Definition*
Useful Waste Heat	This is the heat actually delivered and used to meet the on-site heating demand for a specific process or application at the host site. Useful waste heat may differ significantly from recovered waste heat referred to in CHP manufacturer specifications.
Venting (of Biogas)	Within the context of this report, venting refers to a basis of how biogas is treated for GHG emission accounting purposes. A basis of venting 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).*

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NREL Image Gallery — Wind Turbine

fuelcell.org — Fuel Cells

Executive Summary

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1 EXECUTIVE SUMMARY

1.1 Purpose of this Report

This report fulfills two purposes. First, it identifies the 2012 year impacts of the Self-Generation Incentive Program (SGIP) on California's electricity system. Second, it provides an outlook on the program's ability to deliver peak demand and greenhouse gas emission reduction benefits in the future.

For 2012 impacts, we examine the effect of the SGIP on peak electricity demands, on energy demands (which includes electricity and thermal energy produced during all hours as well as fuel consumed by SGIP systems), and on greenhouse gas (GHG) emissions.[1]

The SGIP is currently set to sunset at the end of 2015.[2] Reducing greenhouse gas emissions and providing peak demand relief are two key metrics for assessing the SGIP's current and future value. The future value outlook is based on the existing portfolio of technologies making up the SGIP, the distributed generation (DG) technologies making up the queue of reserved projects that could receive SGIP incentives, and distributed generation technology performance trends.

1.2 Conclusions and Recommendations

The 2012 SGIP impact evaluation uses twelve years of metered performance data to provide a perspective of current impacts and their connection to historical trends. Based on the information presented throughout this study, we make the following conclusions:

1. **The SGIP has made significant progress in reducing GHG emissions**. Beginning in 2010, the SGIP began to show reduced GHG emissions compared to the grid, reducing GHG emissions in that year by nearly 20,000 metric tons.[3] By the end of 2012, the SGIP was decreasing more than 128,000 metric tons of GHG emissions (as CO_2) per year; an amount equivalent to the GHG emissions of more than 25,000 passenger vehicles.
2. **The SGIP has steadily improved its contribution to peak demand reduction**. In 2010 and 2011, the SGIP reduced the CAISO's peak demand by 92 MW and 106 MW, respectively. By 2012, SGIP projects were reducing the CAISO's peak demand by 123 MW during the 200 top demand hours of 2012. To place this peak demand contribution in context, the SGIP represented approximately 282 MW of capacity at the end of 2012. If viewed as a single power plant, the SGIP's total capacity would rank it 52nd among the 1,144 in-state power plants. Therefore, the "SGIP power plant" contributed 123 MW (nearly 46 percent of its total capacity) to helping reduce peak demand at the time most needed by California's electricity system.
3. **Moving into the future, it appears likely that the SGIP will provide even greater GHG emission reductions and peak demand benefits**. Assuming build-out of the queue of SGIP projects as it looked in early 2013 and continuation of the current program guidelines and rules, GHG emission reductions will grow to over 140,000 metric tons per year by the end of 2016.

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[1] This report represents the twelfth impact evaluation conducted on the SGIP. Prior year impact reports are located on the CPUC website at: http://www.cpuc.ca.gov/PUC/energy/DistGen/sgip/sgipreports.htm

[2] Senate Bill (SB) 412 (Kehoe, 2009).

[3] See "CPUC Self-Generation Incentive Program: Eleventh Year Impact Evaluation." Itron, June 22, 2012, page 6-20.

Similarly, we expect the SGIP contribution to peak demand reduction to increase to nearly 190 MW by the end of 2016.

4. **SGIP is helping to transform the distributed energy resources (DER) market**. Through incentives and lessons learned, the SGIP is helping to lower costs of distributed energy resource technologies, improve their effectiveness in recovering useful waste heat and reduce GHG emissions. However, there is insufficient independent information at this time to quantify these impacts of the SGIP on the DER market.
5. **The SGIP continues to provide a balanced and diversified portfolio of technologies and resources**. One of the primary drivers to the benefits accruing from the SGIP is the diversity of technologies making up the program. This diversity provides utility customers with a broad selection of technology choices. It also provides the program with a portfolio of resources and approaches to achieving GHG emission reductions and addressing peak demand. The early 2013 queue of projects in the SGIP continues to provide good diversity, representing a balanced portfolio of wind, advanced energy storage, fuel cell and clean combined heat and power (CHP) technologies.

The SGIP plays an important role in providing utility customers with choices in how they meet their energy needs. It also provides utility customers with an increasingly vital ability to directly participate in reducing GHG emissions and lowering peak demands on California's electricity system. To ensure that the SGIP continues to play this critical role in the future, we make the following recommendations:

1. **Continue investigating ways to reduce GHG emissions and maximize peak demand benefits**: As presented in this study, the SGIP provides significant levels of GHG emission and peak demand reductions. Based on the early 2013 queue of projects and the current program guidelines and rules, the SGIP will provide even greater GHG and peak demand benefits moving into the future. However, there is still room to obtain even greater levels of benefits with no or minimal additional cost. Increased levels of GHG emissions reductions can be obtained by improving the coincidence of electricity generation and site thermal loads or finding innovative ways to store and use recovered waste heat. In addition, greater GHG reductions can be achieved by increasing the future number of CHP projects at facilities with high demand for heat. The utilities are in a unique position to identify project sites with high thermal demand and work closely with customers to use the SGIP to help capture useful waste heat and reduce GHG emissions.
2. **Measure market transformation impacts resulting from the SGIP**: Through incentives, the SGIP is stimulating production and deployment of DER technologies; thereby helping to lower their capital costs. Similarly, the SGIP has identified important lessons on ways in which DG technologies, especially CHP technologies can help reduce GHG emissions. As more storage systems are deployed under the SGIP, lessons will be learned on ways in which combinations of DG and storage technologies can improve grid reliability and responsiveness. To date, there is little data available to independently assess the market transformation impacts of the SGIP. Independent measurement of the impacts and attribution of those impacts to the SGIP are important in quantifying the benefits and ultimately the value of the benefits. Among the market impacts that should be assessed are distributed energy resource cost reductions, efficiency of heat recovery operations, and GHG emission reductions.

1.3 SGIP Background and Status

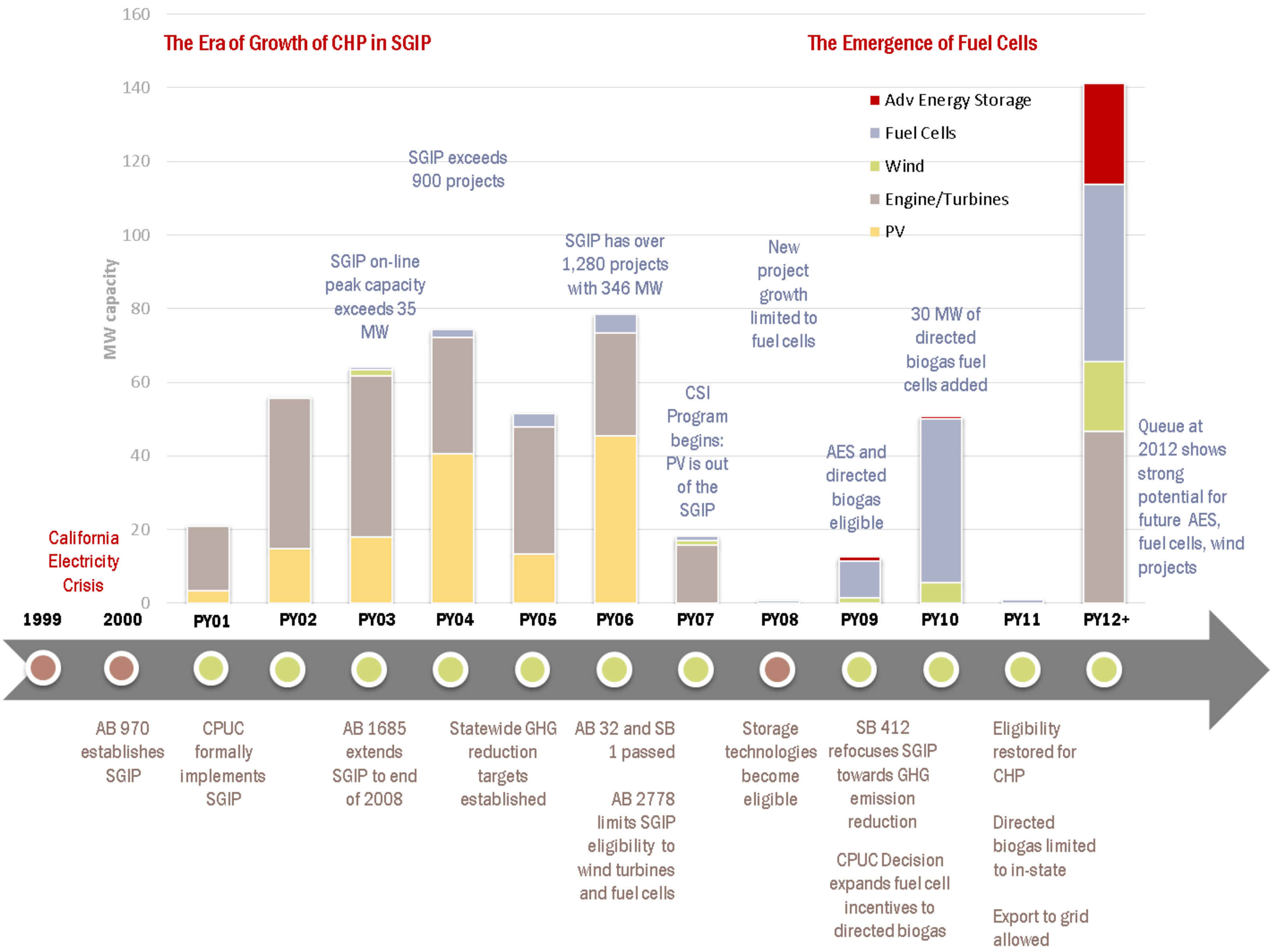
The Self-Generation Incentive Program is a unique California program designed to support installation of distributed generation technologies on the customer side of the meter. The SGIP is overseen by the California Public Utilities Commission (CPUC). Pacific Gas and Electric Company (PG&E), Southern California Edison (SCE), and Southern California Gas Company (SoCalGas or SCG) are the Program Administrators (PAs) throughout their respective service territories. The California Center for Sustainable Energy (CCSE) is the Program Administrator for the San Diego Gas and Electric Company (SDG&E) service territory.

The SGIP represents one of the largest and longest-lived incentive programs for DG and CHP technologies in the country. Initially created in 2001 with an expected four-year life span, the SGIP is entering its twelfth year of operation.

The SGIP has evolved over time to ensure it remains relevant and addresses key issues in developing sustainable distributed generation solutions. A timeline of key events is shown in Figure 1-1.[4]

[4] Note that rebated capacities in Figure 1-1 are reported on a Program Year basis to better show the influence of key events. Appendix A contains a more complete listing of annual and cumulative project counts and rebated capacities broken out in different ways and reported in both program years and calendar years.

Figure 1-1: Key Events over the Lifetime of SGIP



Note: The capacity is shown for the year a project applied to the program, not necessarily the year it was completed and online.

2012 Program Status:

- **Project Count and Capacity**: At the end of calendar year 2012, there were 617 complete projects in the SGIP, representing approximately 294 MW of rebated capacity.[5] Of these complete projects, 22% of the total rebated capacity was known to be offline or decommissioned.[6] Internal combustion engines, gas turbines, and microturbines contributed 212 MW of rebated capacity, representing approximately 72% of the overall capacity of the SGIP. Fuel cells and wind systems together contributed 80 MW; the majority of the remaining capacity of the SGIP.
- **Eligible Costs and Incentives:** Eligible costs represent the combined costs paid by the participants and the amounts provided as incentives. Cumulative SGIP eligible costs exceeded $1.2 billion by the end of calendar year 2012. SGIP incentives accounted for over $400 million, while cumulative SGIP project participant costs exceeded $800 million.[7] Fuel cell and internal combustion engine costs represented over $650 million in combined project participant costs, or over 80% of all SGIP participant project costs. Incentives paid in calendar year 2012 were approximately $109 million. Appendix A provides a complete breakout of eligible project costs and incentives paid each year and cumulatively over the life of the SGIP.

Figure 1-2: SGIP Rebated Capacity (MW) at end of 2012

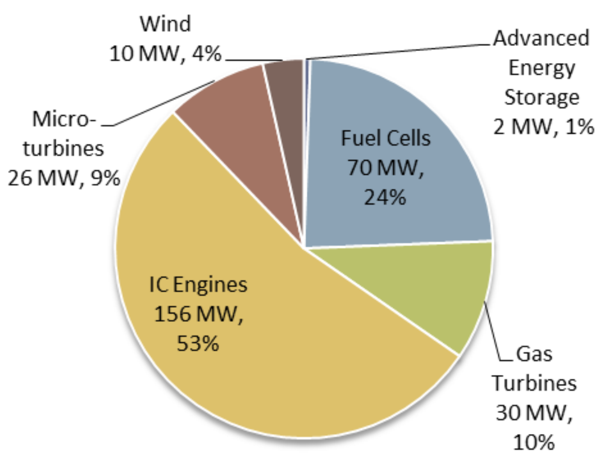
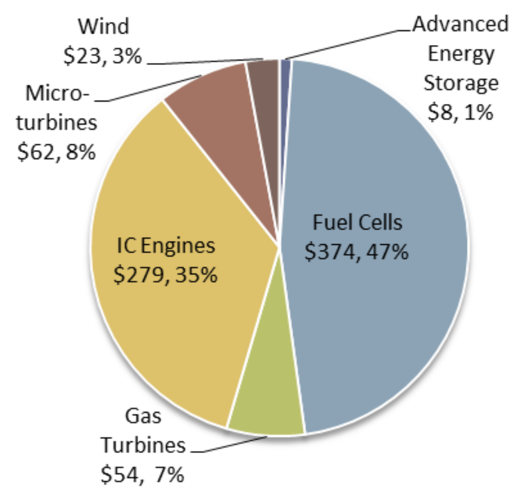


Figure 1-3: SGIP Participant Costs ($ millions) at end of 2012



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5 These values do not include PV projects from pre-2007. If PV projects were included, the total project count would equal 1,507 and the total rebated capacity would equal 430 MW.

6 See Appendix A, Table A-3.

7 These $400 million in SGIP incentives exclude incentives paid out to PV projects prior to 2007. In addition, the cumulative eligible costs exclude PV.

1.4 SGIP 2012 Energy Impacts

Summarized Energy Impacts

- Overall, 601 projects[8] representing approximately 282 MW of rebated capacity generated 970 GWh of electricity and recovered 18.4 million therms of useful heat during 2012.

Table 1-1: Summary of SGIP 2012 Energy Impacts by Program Administrator

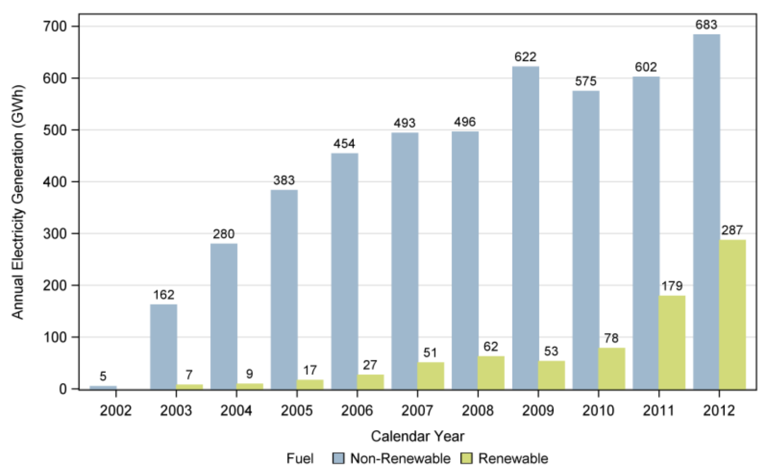
Program Administrator	*Project Count*	*Rebated Capacity (MW)*	*Electricity Generated (GWh)*	*Fuel Consumption (Million Therms LHV)**	*Useful Heat Recovered (Million Therms)*
CCSE	61	33.4	150	10.0	3.0
PG&E	281	109.3	397	28.6	5.9
SCE	116	51.1	129	6.7	1.3
SCG	143	88.5	294	27.4	8.1
Total	**601**	**282.3**	**970**	**72.6**	**18.4**

* Lower Heating Value (LHV) assumes 920 Btu of energy available per cubic foot of natural gas.

Electrical Impacts

- SGIP projects generated 970 GWh of electricity in 2012. The total output is enough to serve the annual needs of over 145,000 homes. This is equivalent to the electricity output of a 110 MW power plant operating every hour of the year at full nameplate capacity.
- Non-renewable projects continue to account for the majority of the SGIP's annual electric generation. Nonetheless, by the end of 2012, 30 percent of the total energy delivered from the SGIP came from renewable fueled projects.

Figure 1-4: SGIP Electrical Generation Trends



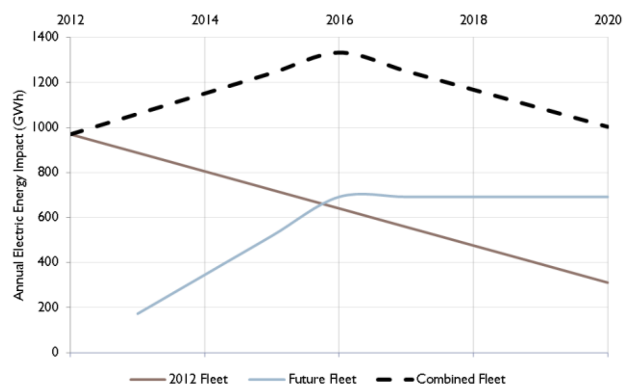
[8] Project counts differ when we refer to impacts versus rebated capacity. In 2012, there was a lack of metered data for wind and advanced energy storage projects. In the case of legacy wind projects, these older wind projects had fallen out of the warranty period and were no longer required to provide metered data. For newer wind and advanced energy storage projects, the projects were not on-line in time to collect 2012 data. Consequently, while there were 617 projects that were completed (i.e., had received incentive checks) at the end of 2012, we only report estimated impacts for 601 projects.

Efficiency and Waste Heat Utilization

- Electrical efficiencies of combustion technologies have remained flat even as systems age, while fuel cell efficiencies have exhibited greater variability. Electric-only fuel cells had the highest observed electrical efficiency of 2012 at a 47% Lower Heating Value (LHV) (42% Higher Heating Value (HHV)).[9]
- With flat electrical efficiencies, this places additional importance on useful waste heat recovery to achieve high overall efficiencies.
- Useful heat recovery rates are important in achieving economically sound operations and reduced GHG emissions. Overall, useful heat recovery rates remain below theoretical maximums.[10]
- Projects that have a coincidence of thermal and electrical loads will have lower GHG emissions. In addition, projects with consistently high thermal loads have higher potential for useful waste heat recovery.

Future Outlook on SGIP Energy Impacts

Figure 1-5: 2012 and Projected Annual Electric Energy Impacts Tthrough 2020[11]



- Looking forward, we assumed complete build-out of the projects currently in the SGIP queue[12] and implemented in accordance with current program guidelines. The resulting *future fleet* has energy impacts increasing each year commensurate with the new capacity. The *2012 fleet* has energy impacts declining each year as more capacity is retired or simply generating at lower levels. The *future fleet* lifts the combined annual energy impact from 970 GWh in 2012 to a peak of 1,330 GWh in 2016. Assuming completion of the SGIP at the end of 2015 and no new applications are received past the end of 2015, impacts from 2016 through 2020 decline along with declines of the *2012 fleet*.[13] The *future fleet* is assumed to maintain a steady level of energy impacts after 2016 due to

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[9] Electrical efficiencies of combustion-based technologies are expressed in Lower and Higher Heating Values (LHV and HHV). HHV assumes condensation of water vapor can be recovered as useful energy. For combustion technologies used in the SGIP, the more conservative LHV is more reflective of the practical level of energy recovery.

[10] In some cases, useful waste heat recovery is due to mismatch between thermal and electrical loads. Other possible reasons for low useful waste heat recovery have been examined in the report "Self-Generation Incentive Program: Combined Heat and Power Performance Investigation," April 1, 2010.

[11] Note that the associated capacity numbers (MW) are shown in Section 4, and the 2016 capacities specifically in Table 4-6.

[12] We took a "snapshot" of the SGIP as of April 12, 2013.

[13] Even though the SGIP ends on December 31, 2015, projects are assumed to reach a complete status during 2016; thereby, increasing the program's rebated capacity in 2016.

the performance based incentive (PBI) structure and the associated longer and more rigorous warranty requirements.

1.5 SGIP 2012 Peak Demand Impacts

CAISO Peak Hour Demand Impacts

- The SGIP impacts on CAISO peak hour demand have tended to increase with increasing capacity of the program.
- The 2012 CAISO peak hour was from 4 to 5 p.m. Pacific Daylight Time on Monday, August 13; the peak demand was 46,682 MW. The estimated impact from SGIP capacity during the CAISO peak is 128 MW.

Top 200 CAISO Peak Hour Demand Impacts

- In 2012, the top 200 hours of CAISO peak demand occurred during 38 of the 85 days between July 10 and October 2. The peak demand during these top 200 hours ranged from 39,200 to 46,700 MW.
- SGIP projects contributed an average peak demand impact of 123 MW during the 200 top demand hours of 2012. The SGIP impacts ranged from 103 MW to 134 MW.
- The SGIP's ability to impact peak demand is reduced as older systems retire. Recommissioning efforts taking place in the DG market outside of SGIP are bringing some of the retired systems back into service, thereby helping restore a portion of the impact potential.

Peak Demand Impact Value

- SGIP peak demand impacts are less than one percent of CAISO total demand, but the relief they provide to the grid has substantial economic value. To estimate a benchmark of that value we consider the avoided costs of demand impacts during the IOUs' top 200 hours of 2012.[14]
- Estimated value of avoided costs of SGIP demand impacts in 2012 is approximately $7 million.

Table 1-2: Estimated Avoided Costs of SGIP Demand Impacts by Electric Utility[15]

Electric Utility	***Achieved Demand Impact Avoided Cost (000 $)***
PG&E	$2,510
SCE	$3,222
SDG&E	$936
Non-IOU	$346
Total	**$7,013**

[14] Avoided cost values are based on an avoided cost model produced for the CPUC by the firm *Energy and Environmental Economics* (E3)

[15] The SGIP provides benefits in four areas; Table 1-2 represents only the value associated with peak demand reduction.

Future Outlook on SGIP Peak Demand Impacts

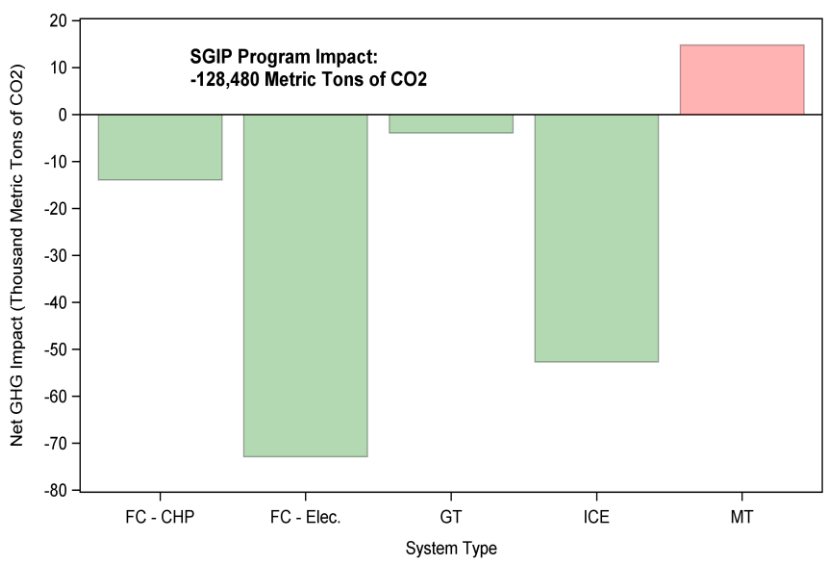
- To investigate possible peak demand impacts of the SGIP, we projected demand impacts from a combination of SGIP's 282 MW of existing capacity and technology portfolio and the 141 MW portfolio of capacity represented by the 2013 queue of reserved systems.
- Total program demand impact increases through 2016 to a maximum of 189 MW. Assuming completion of the SGIP at the end of 2015 and no new applications are received past the end of 2015, demand impact declines as capacity additions stop, and capacity from the 2012 fleet either retires or simply generates at lower levels. Capacity grows by 51% from 2012 to 2016 while demand impact increases by 48% from the 2012 demand impact. The decline in impact from the 2012 fleet is offset in part by high capacity factors assumed for much of the new fleet capacity as a result of the PBI requirements.

1.6 SGIP 2012 GHG Emission Impacts

Overall GHG Impacts

- In 2012, the SGIP was responsible for a net reduction in GHG emissions of more than 128 thousand metric tons of CO_2 — equivalent to removing the GHG emissions from over 25,000 passenger vehicles per year in California.[16]
- All-electric fuel cells and IC engines achieved the greatest GHG emission reductions. Fuel cells with heat recovery and gas turbines achieved marginal reductions, while microturbines were the only technology that increased net GHG emissions. Each utility realized some level of net GHG emission reductions in 2012.

Figure 1-6: GHG Impact by Technology (2012)



[16] This assumes the average passenger vehicle emits approximately 423 grams of CO_2 per mile and an average annual mileage of 12,000 miles per year. See "Greenhouse Gas Emissions from a Typical Passenger Vehicle," EPA Fact Sheet EPA-420-F-11-041, December 2011. (http://www.epa.gov/otaq/climate/documents/420f11041.pdf)

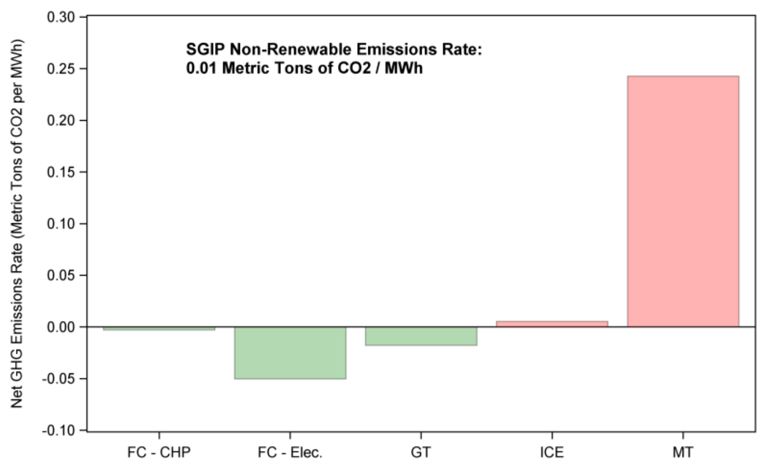
Table 1-3: GHG Impact by Program Administrator (2012)

Program Administrator	*Net GHG Impact (Tons of CO_2)*	*Percent of GHG Impact (%)*
CCSE	-15,818	12%
PG&E	-69,008	54%
SCE	-25,115	20%
SCG	-18,539	14%
Total	**-128,480**	**100%**

2012 Non-Renewable GHG Performance (Pre-SB 412)

- Non-renewable SGIP systems installed prior to SB 412 implementation include fuel cells, gas turbines, internal combustion engines, and microturbines. These projects have been 'grandfathered' under SB 412 provisions and current SGIP rules which prohibit net-GHG emitting technologies.
- Fuel cells and gas turbines were the only non-renewable SGIP technologies that reduced GHG emissions. All-electric fuel cells achieve reductions exclusively by generating electricity more efficiently and cleaner than the avoided generator on the grid.

Figure 1-7: Non-Renewable GHG Emissions Impacts by Technology Type (Tons CO_2/MWh)



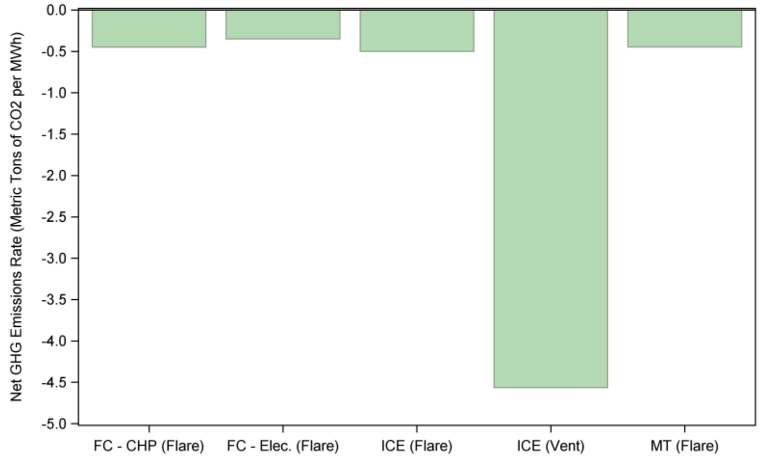
- Non-renewable internal combustion engines and microturbines generated more emissions than they avoided in 2012. For both technologies, not enough waste heat was recovered to offset the increased emissions due to the electricity generation being less efficient than electricity generated from the grid. Going forward, PBI requirements will increase waste heat recovery, thereby helping non-renewable projects achieve GHG reductions.

2012 Renewable Biogas GHG Performance

- Renewable fueled projects in the SGIP are those powered by biogas. Sources of biogas include landfills, wastewater treatment plants (WWTP), dairies, and food processing facilities.

- All renewable systems have negative (reducing) net GHG emissions rates due to avoided methane emissions. Systems with flaring biogas baselines achieved reductions between 0.35 and 0.50 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 4.60 metric tons of CO_2Eq per MWh.

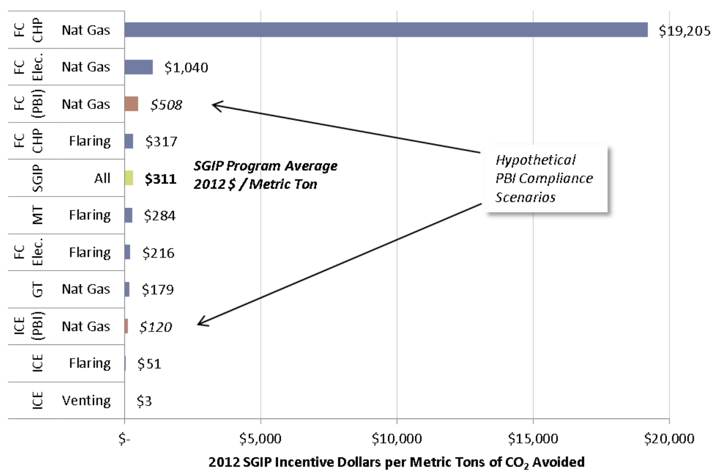
Figure 1-8: Renewable Biogas Net GHG Emissions Rates



Valuing SGIP GHG Reductions

- SGIP technologies show a wide range of costs to reduce GHG emissions, with some of the lowest costs associated with renewable-fueled technologies that prevent venting of biogas to the atmosphere. Through 2012, the SGIP spent on average \$311 per metric ton of CO_2 reductions.

Figure 1-9: Comparing GHG Emission Reduction Costs by Technology and Fuel Type



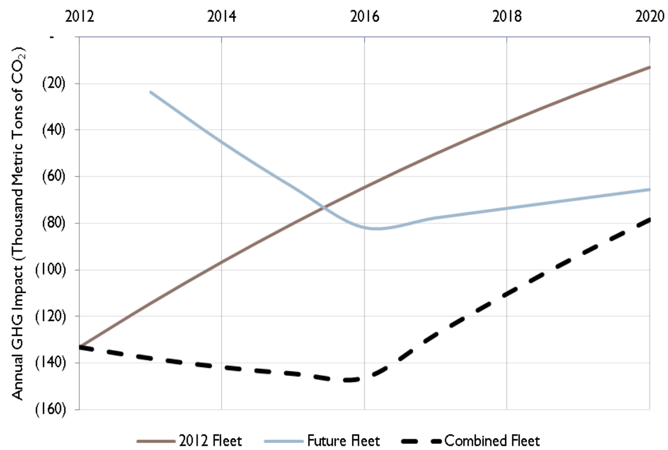
- The 2011 Handbook changes for PBI will have a significant effect on the cost of reducing GHG emissions. Pre-PBI costs for reducing GHG from non-renewable fuel cells with low waste heat recovery are high; under the PBI requirements, the cost for reducing GHG from the same non-renewable fuel cells drops significantly. It should also be noted that reducing GHG emissions is one of four goals of the SGIP.

Future Outlook on SGIP GHG Impacts

- As with energy and peak demand impacts, we projected GHG emission impacts in the future for the SGIP assuming a complete build-out of the existing queue of projects, completion of the SGIP at the end of 2015 and no new applications received past the end of 2015. However, we also assumed the future projects would at minimum adhere to the PBI performance requirement of zero net increase in GHG emissions.
- The GHG impacts of the 2012 fleet are projected to diminish from a reduction of 130 thousand metric tons of CO_2 in 2012 to less than 20 thousand tons of CO_2 in 2020, due to aging and reduced overall capacity factors.

- The GHG impacts of the future fleet are projected to begin in 2013 at just over 20 thousand metric tons of CO_2 reductions and reach a maximum of just over 80 thousand metric tons of CO_2 reductions in 2016. GHG impacts are expected to increase (more reductions) through 2016 as more capacity is added each year. All projects in the SGIP queue were assumed to be completed by 2016.

Figure 1-10: Projected SGIP GHG Impacts through 2020



- Future GHG impacts will be negatively affected by improvements in grid marginal emissions rates as the grid becomes greener, making it more difficult for SGIP projects to achieve net GHG reductions.

- The impacts of the combined fleet represent the sum of the 2012 fleet and the future fleet. Overall, the GHG impact of the SGIP is expected to diminish from a reduction of 130 thousand metric tons of CO_2 to approximately 80 thousand metric tons of CO_2 reduced in 2020.

1.7 SGIP and Distributed Generation Market Transformation

- Assisting in market transformation of distributed generation technologies is one of the four primary goals of the SGIP.

- SGIP helps in DG market transformation by leading to increased production of DG technologies with associated improvements to the efficiency with which the technologies are produced (i.e., "learning curves"). Cost modeling of DG technologies shows that DG costs can be expected to decrease moving into the future.

- There is large and unmet potential for DG and CHP technologies in California. Decreasing DG costs will act as market drivers to increased DG growth. In turn, state and federal policies on renewables, climate change, and CHP will help spur additional growth and advancement in DG technologies.

- One example of how SGIP may influence DG market transformation is through increased improvements and efficiency of CHP technologies. The combination of decreased costs through learning curves and increased useful waste heat recovery rates will help spur development of CHP technologies in the commercial and industrial sectors.

Introduction and Objectives

2

2 INTRODUCTION AND OBJECTIVES

The Self-Generation Incentive Program (SGIP) is an incentive program providing support to distributed generation and storage systems located at utility customer facilities. Funded by California ratepayers, the SGIP is managed by Program Administrators (PAs) representing California's major investor owned utilities.[1] The California Public Utilities Commission (CPUC) provides program oversight.

During the summer of 2000, California experienced a series of rolling blackouts that left thousands of electricity customers in Northern California without power and shut down hundreds of businesses. As part of their response, the Legislature established the SGIP in 2001 to help reduce peak demand problems.[2] The SGIP created a pathway for interested customers to help meet their own energy needs, thereby reducing peak demand needs on the utility. Over the years, the SGIP has evolved to address changes in California's energy and environmental landscapes. In 2011, reducing greenhouse gas (GHG) emissions became one of the primary goals of the SGIP.[3]

A broad variety of distributed generation (DG) systems are supported under the SGIP. Prior to 2007, the SGIP provided incentives to both fossil-fueled and biogas-fueled gas turbines, internal combustion (IC) engines, fuel cells and microturbines; as well as to solar photovoltaic (PV) and wind turbine systems. With the emergence of the California Solar Initiative (CSI), PV system eligibility was eliminated in 2007. PV incentives were provided instead under the CSI. Beginning in 2008, the list of eligible technologies was expanded to include advanced energy storage systems coupled with renewable energy systems, waste heat to power systems and pressure reduction turbines. Gas turbines, microturbines and internal combustion engines were excluded from the SGIP starting in 2007. These technologies became eligible again in 2011 along with stand alone advanced energy storage systems following a review of their benefits to the program and ratepayers.

2.1 Project Definitions

We categorized the status of SGIP projects into three groups according to their stage of development within the SGIP implementation process: Active projects, Inactive projects, and Complete projects. Program administrators use significantly more classifications in defining project stages in the implementation process. However, for the purpose of grouping SGIP projects to assess impacts, we have stayed with a more general set of classifications.

Active projects have applied for a rebate and are in the queue working through the program requirements needed to receive an incentive payment. These represent SGIP projects that have not been withdrawn, rejected, completed, or placed on a waiting list. Over time, Active projects will migrate either to the Complete or to the Inactive category.

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[1] The Program Administrators are Pacific Gas & Electric (PG&E), Southern California Edison (SCE), Southern California Gas Company (SCG) and the California Center for Sustainable Energy (CCSE) which represents San Diego Gas & Electric (SDG&E).

[2] 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

[3] The CPUC Decision 11-09-015 (September 8, 2011) lays out the four primary purposes of the SGIP and guiding principles.

Inactive projects consist of SGIP projects that are no longer making forward progress in the SGIP implementation process. These projects have been withdrawn, rejected or cancelled by the applicant or the Program Administrator.

Complete projects represent SGIP projects for which the generation system has been installed, the system installation verified through an on-site inspection, and an incentive payment has been issued. The impacts evaluation is conducted on all projects in the Complete category.

Complete projects are further classified into Online, Decommissioned, and Offline categories. Online projects include projects that are currently operational. However, Online projects also include projects that may be down temporarily for various reasons such as maintenance or repair. Decommissioned projects are ones in which the SGIP generation equipment has been disconnected and removed from the project site. Offline projects are defined as those having a 2012 annual capacity factor less that 0.05. There are also projects for which we do not know the operational status because the project applicants are no longer traceable.

For reporting purposes, we group Complete SGIP projects by Program Year (PY) or Calendar Year (CY). Complete SGIP projects are grouped by Program Year to help associate them with specific SGIP Handbook requirements or to connect them with other time specific requirements (e.g., legislative or environmental regulations). When grouping Complete SGIP projects by Program Year, the application date is used to determine their Program Year. Alternatively, complete SGIP projects may be grouped by Calendar Year to identify when the impacts first occur. We use the “check issued” date to group complete SGIP projects by Calendar Year. Throughout this SGIP impact evaluation, results are reported by Calendar Year unless specifically stated otherwise.

2.2 Purpose of this Report

There are two primary purposes of this report. The first is identifying the 2012 year impacts of the SGIP on California’s electricity system. We examine the effect of the SGIP on peak electricity demands; on energy demands (which includes electricity and thermal energy produced during all hours as well as fuel consumed by SGIP systems), and on GHG emissions.[4]

The SGIP is currently set to sunset at the end of 2015. Reducing GHG emissions and providing peak demand relief are two key metrics for assessing the SGIP’s current and future value. Consequently, the second purpose of this report is to provide an outlook on the program’s ability to deliver peak demand and GHG emission reduction benefits in the future; and takes into account market transformation aspects of the SGIP. Our outlook is based on the existing portfolio of technologies making up the SGIP, the DG technologies making up the queue of reserved projects that could receive SGIP incentives, and DG technology performance trends.

2.3 Scope

As noted above, this report provides estimates of 2012 impacts of the SGIP and offers an outlook on the program’s ability to provide peak demand relief and GHG emissions reductions going forward. We identify the energy and GHG impacts at both the statewide and Program Administrator levels and within

[4] This report represents the twelfth impact evaluation conducted on the SGIP. Prior year impact reports are located on the CPUC website at: http://www.cpuc.ca.gov/PUC/energy/DistGen/sgip/sgipreports.htm

each of these levels by technology and fuel type. Where appropriate, we provide information on key trends with a focus on future prospects rather than historical lessons.

While we present information on the costs of the SGIP to reduce GHG emissions or provide peak demand relief, these are proxy costs based on program incentives paid to the projects. The intent is to provide some idea of the value associated with reducing GHG or achieving peak demand relief. This study is not a cost-effectiveness evaluation.

2.4 Organization of this Report

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

- ***Section 1*** *provides an executive summary of the key findings and recommendations*
- ***Section 2*** *is this introduction and lays out the objectives of the report*
- ***Section 3*** *provides important background on the SGIP and the status of the program at the end of 2012*
- ***Section 4*** *delivers information on the energy impacts resulting from the SGIP by the end of 2012 and looking out into the future towards 2020*
- ***Section 5*** *identifies impacts of the SGIP on peak electricity demand as of 2012, discusses the value of the peak reduction benefits and examines peak demand prospects looking out into the future towards 2020*
- ***Section 6*** *presents information on the impacts of the SGIP on GHG emission reductions, identifies the costs of achieving the GHG reductions by technology and fuel and examines the potential GHG benefits of the program moving forward*
- ***Section 7*** *presents information on market transformation aspects of distributed generation resources as affected by SGIP*
- ***Appendix A*** *identifies sources of information for the report and provides additional details on important SGIP characteristics*
- ***Appendix B*** *describes the methods we use in estimating energy and peak demand impacts*
- ***Appendix C*** *provides the methods we use in estimating GHG emission reduction impacts*
- ***Appendix D*** *explains our method for treating and estimating uncertainty associated with the impact results*

Background and Status

3

3 BACKGROUND AND STATUS

California's Self Generation Incentive Program (SGIP) is one of a number of incentive programs in the United States designed to provide support to distributed generation (DG), combined heat and power (CHP), and advanced energy storage (AES) technologies. As of the end of 2012, thirty-seven states offered some form of incentive for DG or CHP programs.[1] Programs similar to the SGIP are operated in New York, Massachusetts, New Jersey, Connecticut, and Michigan among others. California's SGIP is distinct in a number of ways. Established in 2001, the SGIP is one of the longest-lived DG incentive programs in the country. The SGIP has been operating for over twelve years; only New York's CHP program has been longer lived. The SGIP is also unique in the transparency of program results. Detailed impact reports, process evaluations, economic analyses, and special topical reports have been produced since the creation of the program and are freely available on public websites.[2] Another distinctive and important feature of the SGIP is how it has evolved to meet the changing needs of California's ratepayers and citizens. As the SGIP has evolved, there have been accompanying changes in the technologies and key market players in the program. The following section discusses some of the key changes in state government policies, the SGIP guidelines, and the energy market conditions or players that have influenced the SGIP portfolio and may affect the future mix of technologies and impacts.

3.1 Key Events in the SGIP's History

The annual capacity growth from 1999 to 2012 and key events in the SGIP, including energy and environmental policies, market conditions, and the emergence of crucial market players are shown in the timeline of Figure 3-1.[3]

Policy Influences

Energy and environmental policies have strongly shaped the SGIP. The SGIP was originally developed in response to California's electricity crises. In late 1996, California's electricity system was just entering a deregulated energy market. By the start of 2000, California experienced increasing wholesale electricity prices, constrained transmission lines, and the manipulation of energy markets. By May of 2000, power reserves dropped below 5 percent for the first time, and California experienced a series of rolling blackouts. In response, the California Legislature passed a number of bills to help reduce the state's electricity demand. In September of 2000, AB 970[4] established the SGIP as a peak-load reduction program. In March of 2001, the CPUC formally created the SGIP and the first SGIP application was received in July of 2001.

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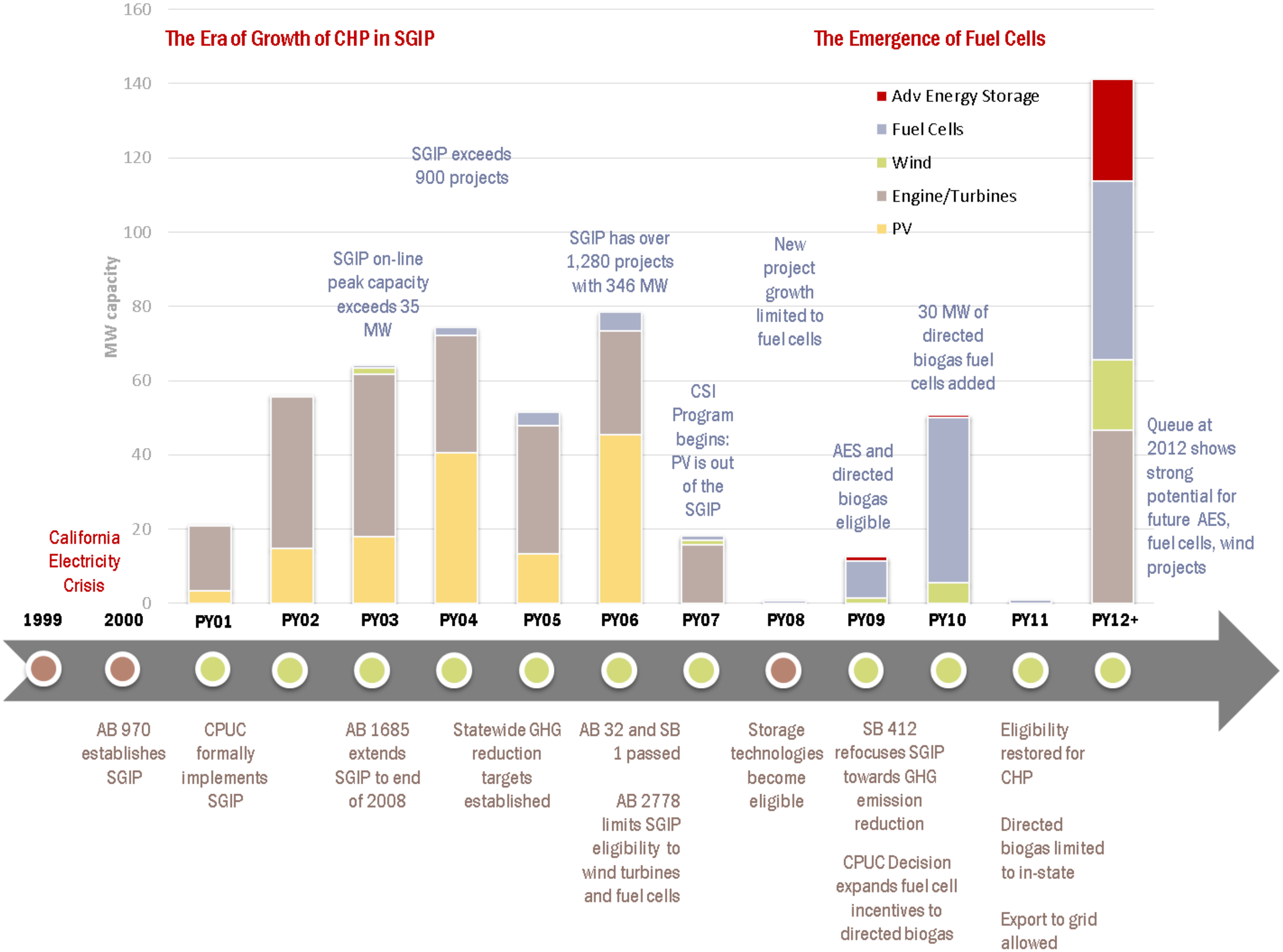
[1] Database for State Incentives for Renewables & Efficiency, http://www.dsireusa.org/

[2] For example, a listing of all past and current reports on the SGIP can be found at California Public Utilities Commission (CPUC) website: http://www.cpuc.ca.gov/PUC/energy/DistGen/sgip/

[3] Note that rebated capacities in Figure 3-1 are reported on a Program Year basis to better shown the influence of key events. Appendix A contains a more complete listing of annual and cumulative system counts and rebated capacities broken out in different ways.

[4] Assembly Bill 970, California Energy Security and Reliability Act of 2000, Ducheny, Chaptered September 7, 2000.

Figure 3-1: SGIP Timeline: Annual Capacity over Time and Key Events



Note: The capacity is shown for the year a project applied to the program, not necessarily the year it was completed and online.

From the onset, the SGIP was an attractive program to consumers interested in controlling energy costs. From a modest start of 70 systems at the end of Program Year (PY) 2001, the SGIP had grown to 520 systems by the end of PY03. The SGIP was also making concrete progress towards addressing peak demand. SGIP output during the PY03 CAISO peak exceeded 35 MW. In addition, with over 140 MW of total rebated capacity, the SGIP represented a significant portion of California's emerging small-scale DG market. To place the SGIP capacity in context, at the time there were approximately 10,000 MW of DG capacity installed throughout California.[5] Less than five percent of that DG capacity (approximately 500 MW) involved systems in the small-scale size range of the SGIP (i.e., smaller than 5 MW).[6] Consequently, the SGIP's 140 MW represented nearly 30% of the state's small-scale DG capacity. In October of 2003, the Legislature passed and the Governor signed Assembly Bill 1685, extending the SGIP through the end of 2008.

By PY03, the SGIP was composed of a mix of solar photovoltaic (PV) systems, fuel cells, wind turbines, and combustion-based technologies. The combustion-based technologies included internal combustion (IC) engines, small gas turbines, and microturbines. These combustion-based systems were fueled by natural gas, biogas or a blend of the two.[7] Concerns over air pollution emissions from combustion-based DG systems would lead to a significant change in the SGIP portfolio.[8] When the Legislature passed AB 1685 (Leno) in October of 2003, it restricted future SGIP eligibility of combustion-based DG to systems that met the definition of "ultra-clean and low-emission" DG. This restriction was based on a California Air Resources Board (CARB) DG certification program, and required that combustion-based DG systems meet specific levels of nitrogen oxides (NO_x) emissions by 2005 and 2007.[9] The intent was to ensure that DG technologies would be as clean as central station combined cycle plants.

DG system eligibility was further limited in the SGIP with passage of AB 2778 (Lieber) in September of 2006.[10] AB 2778 brought about two major changes in the SGIP: First, it directed the CPUC to remove PV technologies from the SGIP. Instead, the CPUC would administer incentives for PV through the California Solar Initiative (CSI). Second, it limited eligibility of non-PV technologies within the SGIP to only wind turbines and fuel cells.

While combustion-based additions of internal combustion engines, microturbines and gas turbines into the SGIP essentially ground to a halt after 2007, there was subsequently a significant growth in fuel cell capacity. In September of 2009, the CPUC issued Decision (D.) 09-09-048. Under this decision,

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[5] DG capacity represents a combination of CHP and DG installations. CHP estimates are from the DOE CHP database; http://www.eea-inc.com/chpdata/

[6] Prior to 2010, SGIP systems were limited to 5 MW in capacity. DG systems greater than 5 MW made up the vast majority of DG installed in California by 2003 developed as Qualifying Facilities under provisions set forth in the Public Utility Regulatory Policy Act (PURPA) of 1978.

[7] Biogas refers to the gas created from the biological breakdown of organic materials and is associated with the anaerobic digestion processes for landfills; waste water treatment facilities and dairy digesters.

[8] Much of the concern over NOx emissions from DG focused on small generators that typically fell outside of air pollution control permit requirements.

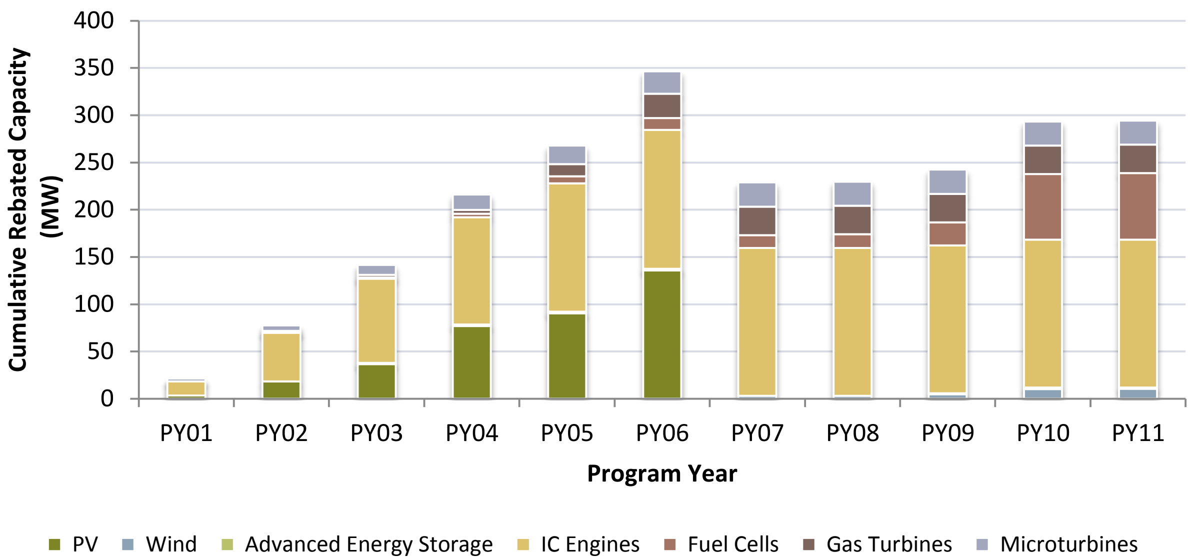
[9] In September of 2000, the Legislature passed Senate Bill 1298. SB 1298 directed the California Air Resources Board (CARB) to develop an air pollution control certification program for DG technologies by January 2003. The CARB certification had a phase in approach that required increasingly lower NOx emissions between 2005 and 2007.

[10] Assembly Bill 2778 (Lieber), chaptered on September 29, 2006

incentives for fuel cell technologies were expanded to include renewable systems using directed biogas.[11] In PY10, there were 55 new directed biogas systems added to the SGIP, all of them fuel cells.

Figure 3-2 shows the change in the makeup of the SGIP over time by program year. The early dominance of internal combustion engine capacity started in PY02. SGIP PV capacity grew significantly through the end of PY06, after which it became accounted for under the CSI program.

Figure 3-2: Makeup of the SGIP over Time (by Program Year)



With PV no longer eligible in the SGIP beginning in 2007,[12] internal combustion engines clearly dominated the overall rebated capacity by the end of PY07. Beginning in PY09, fuel cell capacity started to increase and showed strong growth in PY10. There was also some small growth in wind capacity in PY10. From PY07 on through PY11, there was little overall change in the capacity of internal combustion engines.

State policies on climate change would also impact the SGIP portfolio. Passed in September of 2006, AB 32 (Nunez) required the CARB to develop a Scoping Plan to achieve specific levels of greenhouse gas (GHG) emission reductions by 2020.[13] Within the Scoping Plan, CHP technologies were identified as the source of up to 6.7 million metric tons of CO_2-equivalent GHG emission reductions.[14] In October of 2009, the Legislature passed SB 412 (Kehoe), linking the SGIP to the State's Climate Change Goals.[15] In 2011, CPUC D. 11-09-015 set GHG emission reductions as one of the four primary goals of the SGIP; that same decision also opened the SGIP to "other ultraclean and low-emission" DG technologies beyond

[11] CPUC Decision 09-09-048, September 24, 2009.

[12] Starting in PY07, PV was no longer supposed to be reported as part of the SGIP. Consequently, this chart reflects the removal of PV capacity in the SGIP in PY07 and later. Impacts from legacy PV systems installed under the SGIP after 2007 are reported in the CSI impact evaluation studies.

[13] Assembly Bill 32 (Global Warming Solutions Act, Nunez), chaptered September 27, 2006.

[14] California Air Resources Board, "Climate Change Scoping Plan: Appendices," page C-126, December 2008.

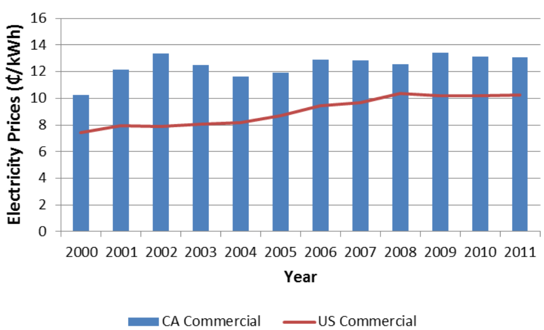
[15] http://www.leginfo.ca.gov/pub/09-10/bill/sen/sb_0401-0450/sb_412_bill_20091011_chaptered.pdf

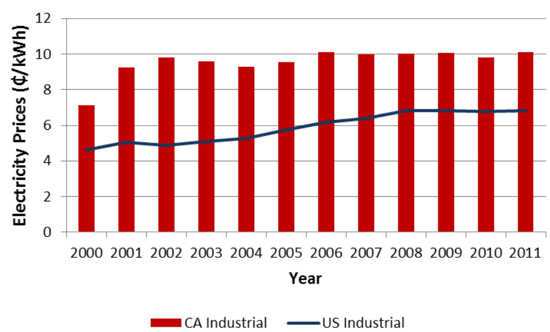
wind turbines and fuel cells. Following an investigation into the costs and benefits of different DG technologies, the CPUC reintroduced CHP back into the SGIP.[16]

3.2 Market Conditions

Electricity and natural gas prices have been significant drivers in the SGIP. When retail electricity prices are high, utility customers show increased interest in on-site DG technologies that can help reduce electric bills. Figure 3-3 shows average commercial and industrial retail electricity prices in California versus the national average from 2000 through 2011.[17] The bars in each of the charts reflect the California retail electricity prices while the lines reflect the national average. In general, California retail electricity prices have historically been significantly above the national average. The relatively higher price for California electricity makes a potentially more attractive case for the installation of DG technologies in California.

Figure 3-3: Average Commercial and Industrial Electricity Prices: CA and US





California electricity and natural gas prices have also shown significant volatility over the years.[18] Interviews with early SGIP participants indicated that concerns over volatility in electricity prices was one of the major reasons they chose to install an on-site DG system.[19]

For utility customers who use on-site boilers to meet their heating needs, the combination of natural gas and electricity prices can affect decisions about installing a CHP system. On one hand, natural gas must be purchased to fuel the CHP system. However, by operating the CHP system, the customer avoids purchasing electricity at retail rates. In addition, the CHP system recovers waste heat, displacing boiler fuel purchases. If the price of electricity is high and the cost of natural gas is low, it may make economic sense for a utility customer to install a CHP system.

Fluctuations in electricity and natural gas prices also impact operation of CHP systems installed by utility customers. The difference between the cost of a purchased kWh of electricity and the cost of natural

[16] The decision also expands eligibility to include pressure reduction turbine technologies, waste heat to power systems, and stand alone advanced energy storage technologies. A copy of Decision D.11-09-015 can be found at: http://www.socalgas.com/documents/business/selfgen/2011/2011Decision.pdf

[17] From http://www.eia.gov/electricity/data/state/

[18] Electricity and natural gas rates taken from http://energyalmanac.ca.gov/electricity/

[19] "CPUC Self-Generation Incentive Program: Fourth-Year Impact Report," Itron, April 15, 2005, pg 10-11

gas to generate a kWh is known as spark spread. With a high spark spread, CHP system owners may lower their overall costs by buying natural gas to run their systems. When spark spread is low, CHP owners may decide to curtail operation of the CHP system and instead purchase electricity from the utility to meet electrical demands and natural gas to meet on-site thermal energy needs.

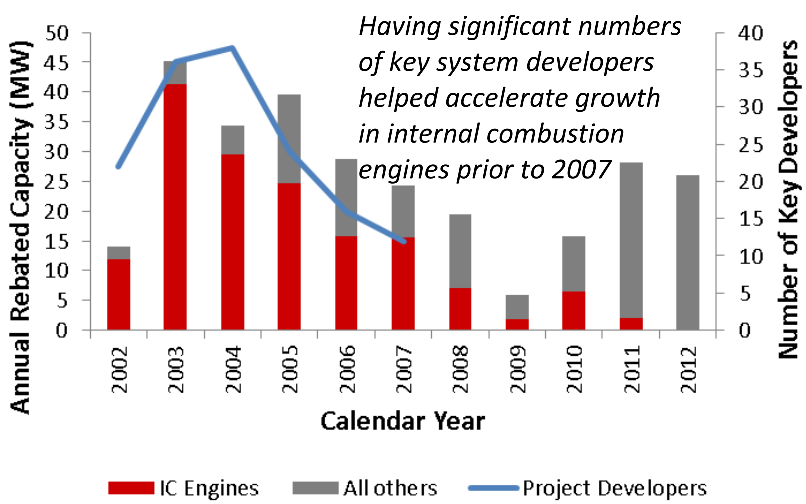
Market Players

Government policies can foster or inhibit the market growth of DG technologies. Attractive energy contracts and energy prices can provide market pull. However, growth in the DG market cannot occur unless there are market players present to take advantage of beneficial policies and market conditions. Examples of key market players include system developers, equipment manufacturers, and third party providers.

Over the course of the SGIP, key market players have influenced the program's portfolio and results. Large numbers of CHP system developers have emerged in the California marketplace in response to the SGIP: In the early SGIP years, there were over 190 different CHP developers, most of whom deployed only a single SGIP system. However, a key group of CHP developers were involved in the installation of a large number of systems.

Figure 3-4 illustrates the role of key CHP developers on internal combustion engine growth in the SGIP. The ability of these CHP developers to respond decisively and quickly to the SGIP resulted in rapid growth of CHP systems early in the program. Moreover, these key CHP developers established a baseline of performance that included how CHP systems were maintained, system warranties, and the targets for useful waste heat recovery. These approaches would have impacts later in the program when the focus shifted to GHG emission reductions.

Figure 3-4: Example of System Developers on Internal Combustion Engine Growth



There was also an assortment of equipment manufacturers active in the SGIP during the early years. There were 25 different CHP manufacturers involved in the over 330 CHP systems completed during the early years. The relatively large number of CHP manufacturers and developers not only led to increased market competition, but created a critical mass within the market to help address institutional barriers. A broader discussion of the SGIP's market transformation effects is presented in Chapter 7.

3.3 SGIP in 2012

Program Capacity

By the end of calendar year (CY) 2012, the SGIP consisted of 617 systems representing 294 MW of rebated capacity.[20] Figure 3-5 shows the rebated capacities and breakdown of technologies making up the SGIP at the end of CY 2012. Table 3-1 summarizes the system count and rebated capacity by technology at the end of CY 2012.

Figure 3-5: Breakdown of SGIP Technologies by Rebated Capacity (2012)

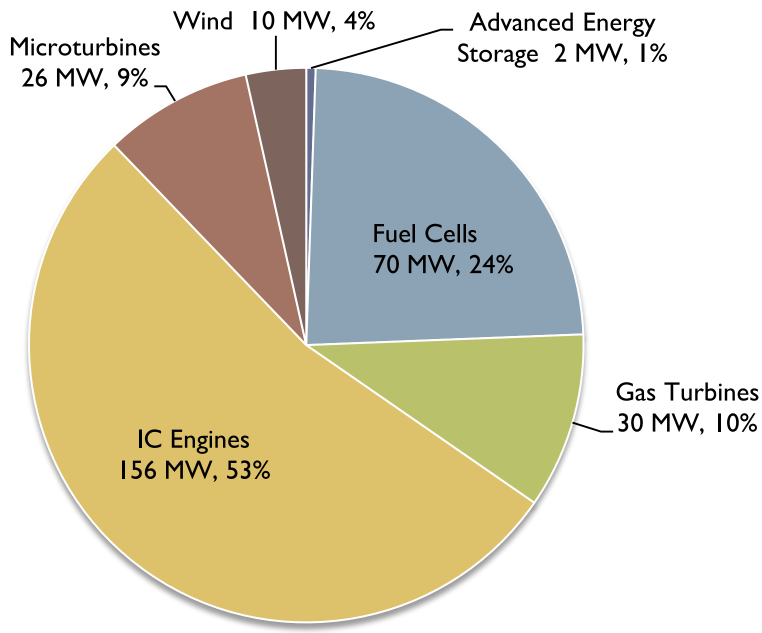


Table 3-1: Project Counts and Capacities by Technology (2012)

Technology Type	*Number of Systems*	*Rebated Capacity (MW)*
Advanced Energy Storage	2	2
Fuel Cells - CHP	103	24
Fuel Cells - Electric Only	92	46
Gas Turbines	9	30
Internal Combustion Engines	256	156
Microturbines	141	26
Wind	14	10
TOTAL	**617**	**294**

[20] These values include Wind and Alternative Energy Storage but do not include PV systems. If PV systems were included, the total system count would equal 1,507 and the total rebated capacity would equal 430 MW.

SGIP systems are distributed among the different IOU service territories. Table 3-2 provides information on the number and rebated capacity of SGIP systems by program administrator (PA) at the end of 2012.

Table 3-2: Number and Capacity of Systems by Program Administrator (2012)

Program Administrator	*Number of Systems*	*Rebated Capacity (MW)*	*Percent of Total Rebated Capacity*
CCSE	61	33	11%
PG&E	291	117	40%
SCE	121	55	19%
SCG	144	89	30%
Total	**617**	**294**	**100%**

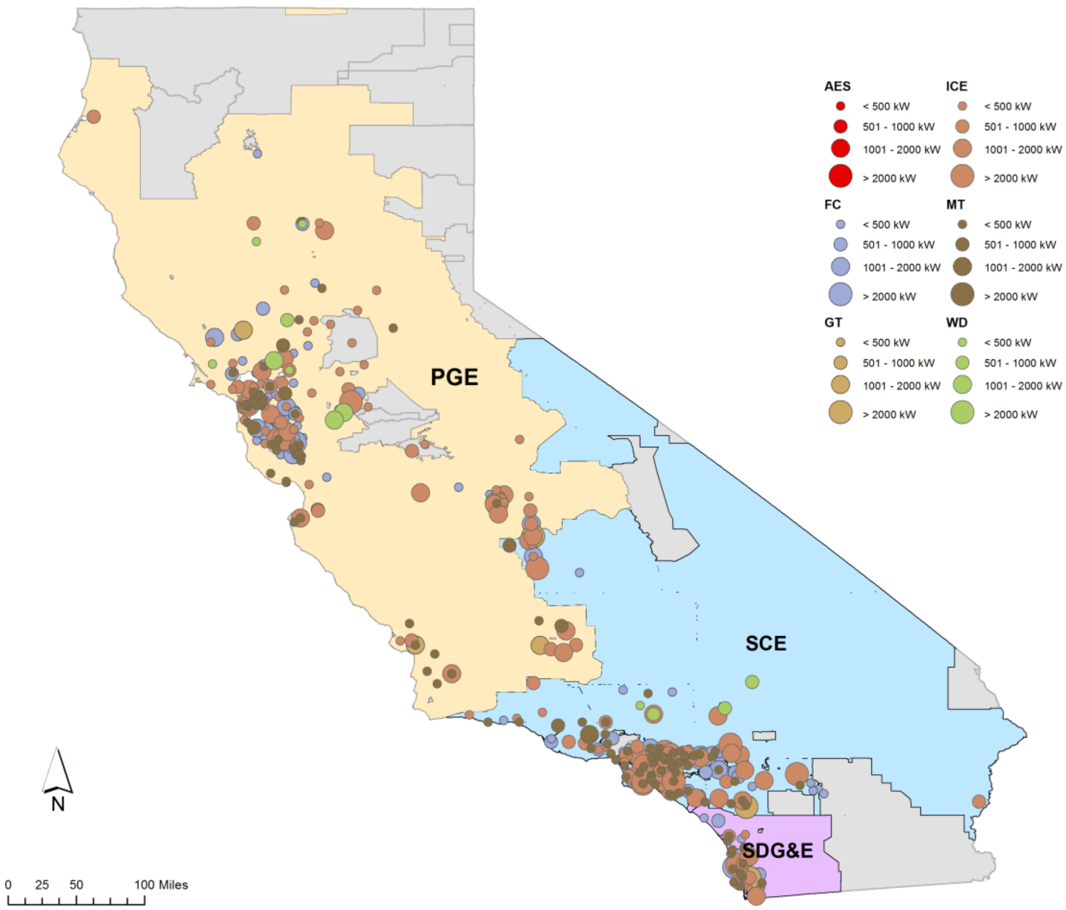
In some instances, SGIP systems overlap IOU and municipal utility service territories. Table 3-3 provides additional information on SGIP breakdown by technology, including a breakdown of systems and technology where there is an overlap between IOU and municipal utility service territories.

Table 3-3: SGIP System Capacity by Program Administrator and Technology (2012)

<table>
<tr><th colspan="2" rowspan="3">Program Administrator / Electric Utility</th><th colspan="6">Technology</th><th colspan="2" rowspan="2">Total</th></tr>
<tr><th colspan="6">(MW)</th></tr>
<tr><th>IC Engine</th><th>Fuel Cell</th><th>Micro-turbine</th><th>Wind</th><th>Gas Turbine</th><th>Advanced Energy Storage</th><th>Total Rebated Capacity (MW)</th><th>Percent of Total Rebated Capacity</th></tr>
<tr><td rowspan="2">CCSE</td><td>IOU</td><td>11</td><td>11</td><td>2</td><td>0</td><td>9</td><td>0</td><td>33</td><td>11%</td></tr>
<tr><td>Municipal</td><td>0</td><td>0</td><td>0</td><td>0</td><td>0</td><td>0</td><td>0</td><td>0%</td></tr>
<tr><td rowspan="2">PG&E</td><td>IOU</td><td>62</td><td>32</td><td>11</td><td>3</td><td>4</td><td>0</td><td>112</td><td>38%</td></tr>
<tr><td>Municipal</td><td>0</td><td>0</td><td>0</td><td>4</td><td>0</td><td>1</td><td>5</td><td>2%</td></tr>
<tr><td rowspan="2">SCE</td><td>IOU</td><td>31</td><td>14</td><td>6</td><td>4</td><td>0</td><td>0</td><td>55</td><td>19%</td></tr>
<tr><td>Municipal</td><td>0</td><td>0</td><td>0</td><td>0</td><td>0</td><td>0</td><td>0</td><td>0%</td></tr>
<tr><td rowspan="2">SCG</td><td>IOU</td><td>50</td><td>5</td><td>5</td><td>0</td><td>17</td><td>1</td><td>77</td><td>26%</td></tr>
<tr><td>Municipal</td><td>3</td><td>7</td><td>2</td><td>0</td><td>0</td><td>0</td><td>12</td><td>4%</td></tr>
<tr><td colspan="2">Total</td><td>156</td><td>70</td><td>26</td><td>10</td><td>30</td><td>2</td><td>294</td><td>100%</td></tr>
</table>

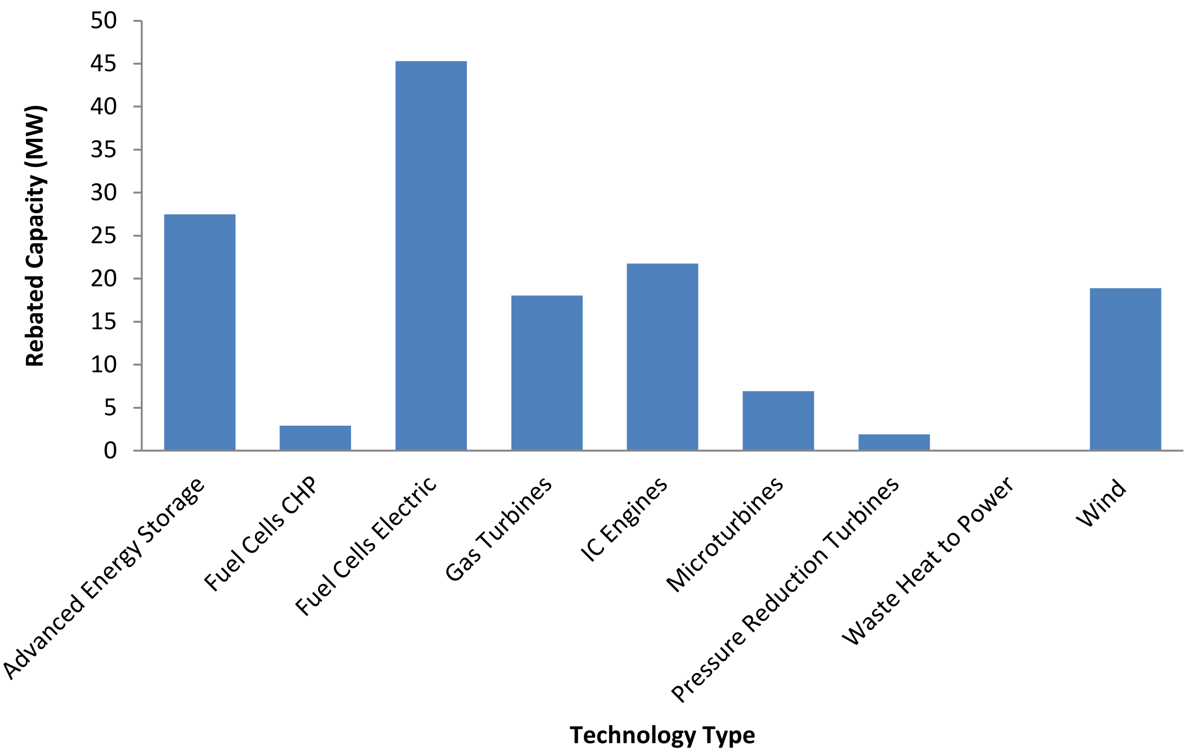
As shown in Figure 3-6, SGIP systems are located geographically throughout California, with a higher concentration of systems in the Bay Area and Southern California (Los Angeles and San Diego) regions.

Figure 3-6: Geographical Distribution of SGIP Systems



There are a sizeable number of systems in the SGIP queue that could influence the future composition of the SGIP. Figure 3-7 depicts a breakdown of technologies in the SGIP reservation queue as of April 2013. There are a total of 786 systems with a potential rebated capacity of over 140 MW in the queue. Approximately 50% of the systems in the queue are fuel cells or advanced energy storage technologies.

Figure 3-7: Summary of SGIP Queue as of April 2013

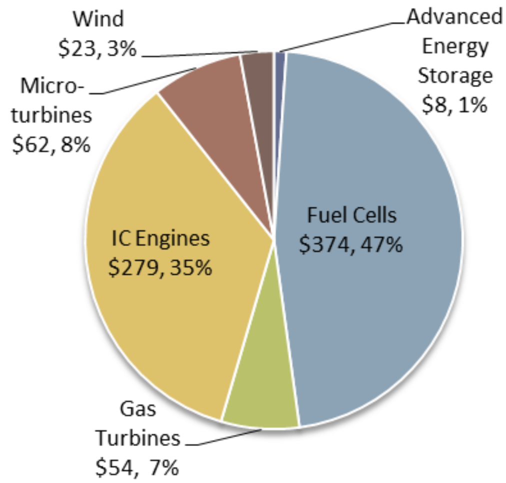


Eligible Costs and Incentives Paid

Eligible costs represent the combined costs paid by the participants and the amounts provided as incentives. Cumulative SGIP eligible costs exceeded $1.2 billion by the end of 2012, with SGIP incentives accounting for over $400 million and cumulative SGIP project participant costs exceeding $800 million.[21] A breakdown of the project costs by technology type is shown in Figure 3-8.

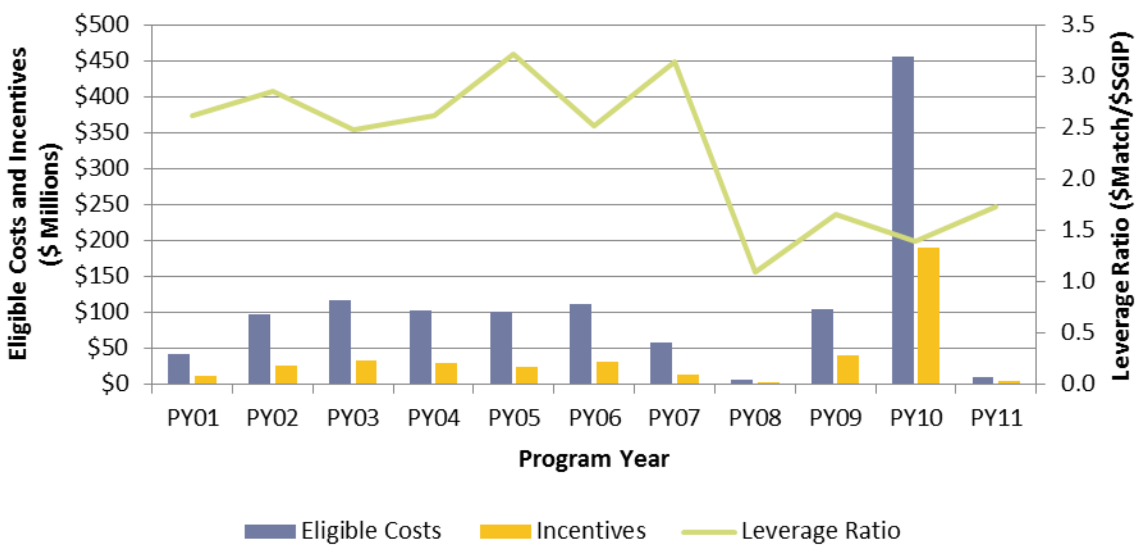
[21] These $400 million in SGIP incentives exclude incentives paid out to PV systems prior to 2007.

Figure 3-8: Cumulative Participant Costs at End of 2012 ($ Millions)



One of the significant changes made to the SGIP was the movement away from upfront capacity incentive payments to performance-based incentives (PBI) for systems 30 kW or greater, which are paid out over time.[22] The change occurred in 2011. Figure 3-9 shows the historical trend on SGIP incentives paid versus match funds provided each year, and the leverage ratio of match funds-to-SGIP funds.

Figure 3-9: Trend on SGIP Incentives and Match



Additional information on SGIP capacities, costs and incentives is contained in Appendix A.

[22] Self-Generation Incentive Program Handbook, November 7, 2011. http://www.pge.com/includes/docs/pdfs/shared/newgenerator/selfgeneration/SGIP_Handbook_2011.pdf

2012 Energy Impacts

4

4 2012 ENERGY IMPACTS

The Self Generation Incentive Program (SGIP) provides financial incentives for installing on-site distributed generation (DG) systems to meet all or a portion of the energy needs of a site. The energy needs of an SGIP host site include electrical energy and thermal energy in the form of steam, hot water, or chilled water. Some SGIP technologies consume natural gas or renewable biogas and convert its energy for use in serving on-site loads.

This section discusses the energy impacts that are attributed to the SGIP. These impacts are based on metered performance data collected from program participants and meters installed for Measurement and Evaluation (M&E) purposes. Impacts of unmetered systems were estimated using ratio analysis. A more detailed discussion of the sources of data and estimation methodology is provided in Appendix A and Appendix B. This section is organized into the following sub-sections:

- *Summary of Energy Impacts,*
- *Electrical Impacts,*
- *Efficiency and Heat Utilization, and*
- *Future Energy Impacts Including Capacity in the Queue*

4.1 Summary of Energy Impacts

This section summarizes the electricity generation, useful heat recovery, and fuel consumption impacts of the SGIP through 2012. Electricity impacts from wind, and alternative energy storage (AES) systems deployed under the SGIP are not included in this section due to a lack of metered data in 2012 for these systems. Consequently, the project counts and capacities reported in this section exclude wind and AES.

Table 4-1 is a summary listing of the electricity,[1] natural gas fuel consumption,[2] and useful heat recovery impacts attributed to the SGIP. Impacts are broken out by technology and fuel type. Table 4-1 also provides estimates of overall energy efficiencies associated with these technologies, where applicable. Due to the variability and difficulty in quantifying the energy content of biogas, fuel consumption estimates for renewable fueled projects are not included.

[1] Within this report, electricity impacts represent the electrical output of SGIP sites net of parasitic loads, such as pumps, blowers, and data acquisition systems.

[2] Natural gas fuel consumption refers to the natural gas used to fuel SGIP systems. It does not account for the natural gas consumed by on-site boilers, or the natural gas avoided by recovery of useful waste heat.

Table 4-1: Summary of Energy Impacts and Overall System Efficiency by Technology and Fuel Type

Technology / Fuel	*Project Count**	*Rebated Capacity (MW)*	*Electricity Generation (GWh)*	*Fuel Consumption (Million Therms LHV)†*	*Useful Heat Recovered (Million Therms)*	*Overall System Efficiency (% LHV)*
Fuel Cell	**195**	**70.1**	**376**	**11.6**	**0.5**	**48.7**
Non-Renewable	122	29.5	151	11.6	0.5	48.7
Renewable	73	40.6	225	N/A	0.0	N/A
Gas Turbine	**9**	**30.1**	**220**	**23.4**	**7.7**	**65.0**
Non-Renewable	9	30.1	220	23.4	7.7	65.0
IC Engine	**256**	**156.5**	**301**	**27.4**	**8.3**	**59.2**
Non-Renewable	231	141.6	244	27.4	7.9	59.2
Renewable	25	14.8	57	N/A	0.4	N/A
Microturbine	**141**	**25.5**	**73**	**10.2**	**1.9**	**41.7**
Non-Renewable	119	21.0	69	10.2	1.9	41.7
Renewable	22	4.5	4	N/A	0.0	N/A
TOTAL	**601**	**282.3**	**970**	**72.6**	**18.4**	**N/A**

* There were 617 SGIP projects completed by the end of 2012. The impacts from 16 wind and storage projects are excluded from this table due to a lack of available metered data.
† Fuel consumption values for renewable projects are not included due to a lack of reliable metered biogas data. All other fuel consumption values reported in lower heating value (LHV) assuming 920 Btu of chemical energy per cubic foot of natural gas.

Overall, 601 projects representing 282 MW of rebated capacity generated 970 GWh of electricity and recovered 18.4 million Therms of useful heat during 2012. Fuel cells generated over one-third of the total electrical energy impacts of the program but collectively recovered the least amount of useful heat. Internal combustion (IC) engines and gas turbines recovered the most heat and achieved the highest overall system efficiencies (65 and 59 percent respectively).

The energy impacts attributed to each SGIP Program Administrator (PA) are shown in Table 4-2.

Table 4-2: Summary of Energy Impacts by Program Administrator

*Program Administrator**	*Project Count*	*Rebated Capacity (MW)*	*Electricity Generation (GWh)*	*Fuel Consumption (Million Therms LHV)*	*Useful Heat Recovered (Million Therms)*
CCSE	61	33.4	150	10.0	3.0
PG&E	281	109.3	397	28.6	5.9
SCE	116	51.1	129	6.7	1.3
SCG	143	88.5	294	27.4	8.1
TOTAL	**601**	**282.3**	**970**	**72.6**	**18.4**

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

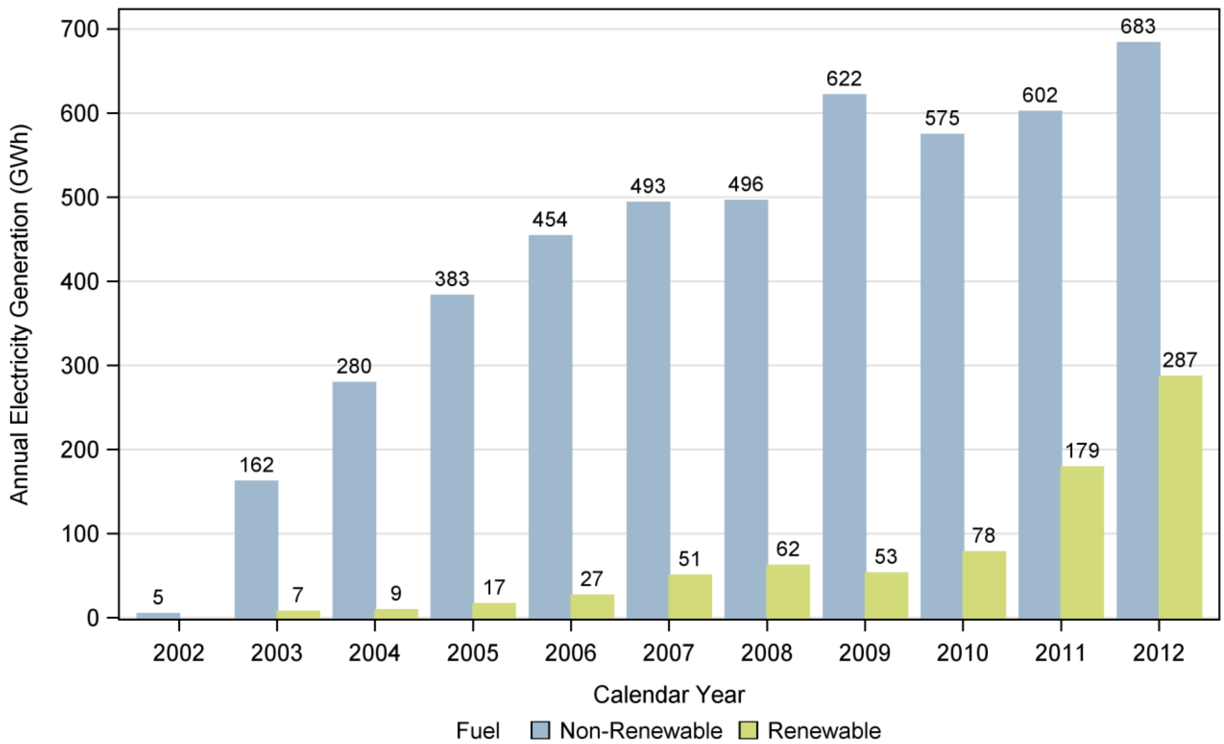
Electricity generation, fuel consumption, and useful heat recovery are important metrics that quantify DG performance. The following sections describe these performance metrics in more detail.

4.2 Electricity Generation Impacts

SGIP projects generated 970 GWh of electricity in 2012. The total output is enough to serve the annual needs of over 145,000 homes.[3] It is also equivalent to the electrical output of a 110 MW power plant operating every hour of the year at full nameplate capacity.

Figure 4-1 shows the SGIP's annual electricity generation (GWh) from its inception through 2012 by fuel type. Non-renewable projects have and continue to account for the majority of the SGIP's annual electricity generation, however, large increases in renewable capacity were observed in 2011 and 2012. By the end of 2012, 30 percent of the total energy delivered by the SGIP came from renewable fueled projects.

Figure 4-1: Electricity Generation Trends by Fuel Type



The capacity and type of SGIP projects deployed within each program administrator's territory is different. Table 4-3 shows how the 970 GWh of electricity generated by SGIP systems in 2012 are distributed among each program administrator. The table also breaks down the electricity generation by technology and fuel type.

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[3] This assumes a typical California home consumes 6.67 MWh of electricity per year. From Brown, R.E. and Koomey, J.G. *Electricity Use in California: Past Trends and Present Usage Patterns,* Lawrence Berkeley National Laboratory, May 2002. http://enduse.lbl.gov/info/LBNL-47992.pdf. Value derived from Table 2 on page 8.

Table 4-3: SGIP Electricity Generated in 2012 by Program Administrator, Technology and Fuel Type

Technology / Fuel	*Electrical Impact (GWh)*			
	CCSE	*PG&E*	*SCE*	*SCG*
Fuel Cell	**57.6**	**194.3**	**74.1**	**49.7**
Non-Renewable	11.8	103.0	22.1	13.7
Renewable	45.8	91.3	52.0	36.0
Gas Turbine	**78.7**	**18.0**	**0.0**	**123.6**
Non-Renewable	78.7	18.0	0.0	123.6
IC Engine	**11.6**	**142.2**	**45.2**	**102.4**
Non-Renewable	7.1	115.4	31.5	89.9
Renewable	4.5	26.8	13.7	12.5
Microturbine	**1.9**	**43.0**	**10.1**	**17.6**
Non-Renewable	1.2	39.8	9.9	17.6
Renewable	0.7	3.2	0.2	0.0
All Non-Renewable	**98.9**	**276.3**	**63.4**	**244.7**
All Renewable	**50.9**	**121.4**	**65.9**	**48.5**
Grand Total	**149.8**	**397.5**	**129.4**	**293.3**

Utilization and Capacity Factor

If all 282 MW of SGIP rebated capacity operated at full nameplate capacity during every hour of 2012, the program would have generated almost 2,480 GWh. This theoretical maximum is more than two and a half times the estimated 970 GWh electrical impact. However, it is unrealistic to expect SGIP projects to generate electricity at full nameplate capacity year round.

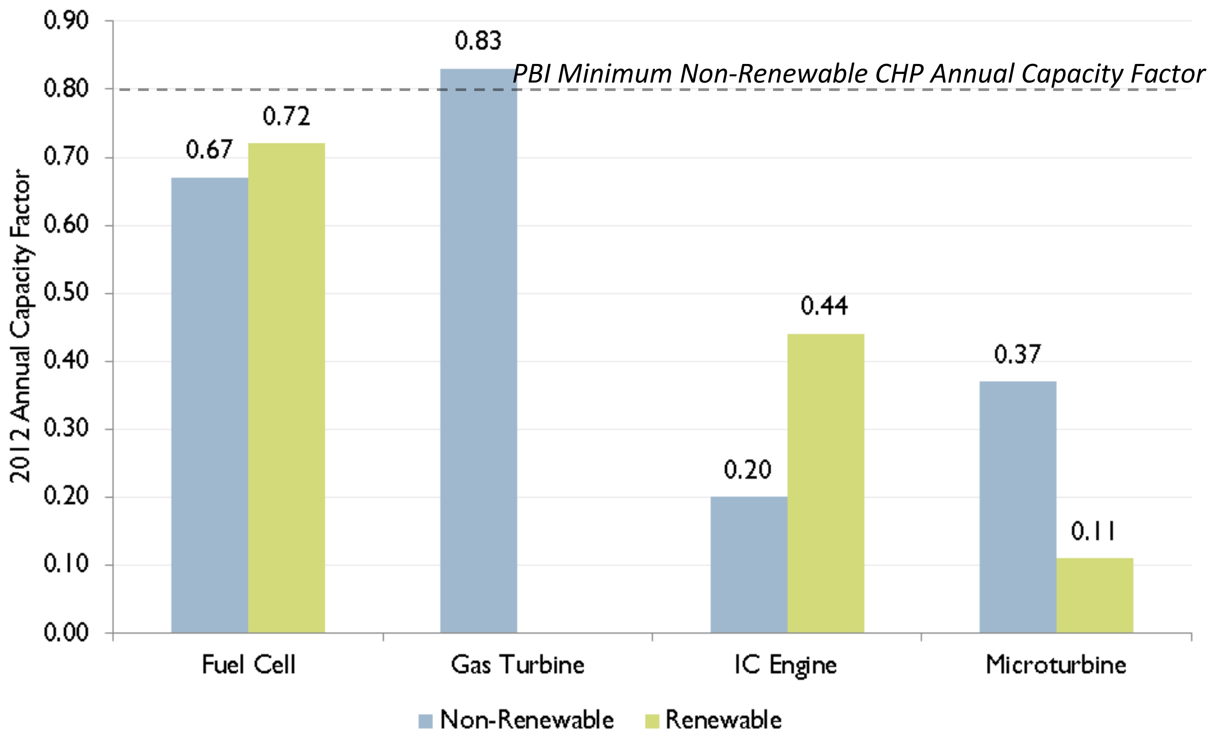
Capacity factor is a measure of utilization and is a function of system output relative to nameplate capacity. In other words, capacity factor indicates the fraction of energy actually generated during a period relative to what could have been generated if the system operated at its full nameplate capacity. A capacity factor of one indicates maximum utilization.[4]

Annual capacity factors by technology and fuel type are shown in Figure 4-2. On average, fuel cells and gas turbines operated the closest to their theoretical maximum during 2012. Internal combustion engines and microturbines had significantly lower capacity factors, indicating lower utilization.

[4] Capacity factors exceeding one are possible but for most systems generally do not last for more than a day.

Also shown on Figure 4-2 is the capacity factor target that recently completed combined heat and power (CHP) projects must achieve to maximize their SGIP performance based incentive (PBI) payment.[5] Non-renewable CHP projects must achieve an annual capacity factor of 0.8 or greater to maximize their SGIP incentive.

Figure 4-2: Utilization (Capacity Factor[6]) by Technology and Fuel Type*



* The vast majority of projects (600/601) completed prior to December 31, 2012 were not subject to the new PBI payment rules and therefore were not penalized for achieving lower capacity factors.

Applying an annual capacity factor of 0.8 to 282 MW of SGIP capacity yields 1,980 GWh of generated electricity, more than twice the amount of electricity actually generated by the SGIP. Factors that influence SGIP annual capacity factor include:

- *Customer operating schedules*
- *Changes in the SGIP fleet composition due to system age*
- *Policy and regulatory changes*

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[5] The 2011 SGIP handbook introduced minimum capacity factors, below which incentive payments will be reduced. The PBI schedule applies to just one of the 601 SGIP systems completed through 2012. The remaining 600 systems are grandfathered under different program rules.

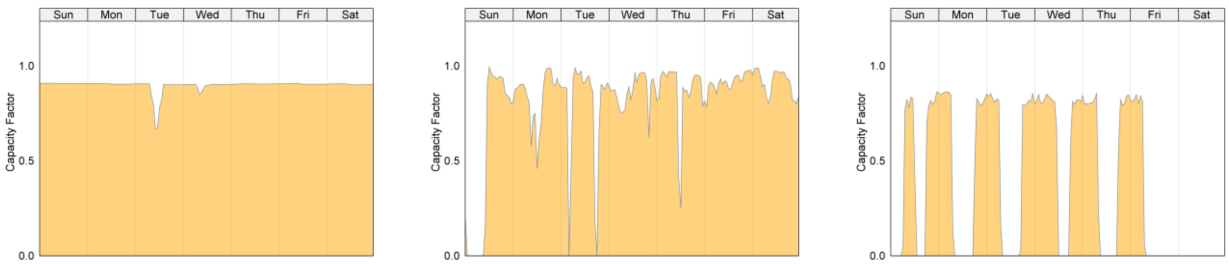
[6] Capacity factors shown in Figure 4-2 represent capacity weighted annual averages.

Customer Operating Schedules

Capacity factors are functions of generating schedules that dictate output levels; they are not necessarily indicators of better or worse performance. However, capacity factors allow direct comparisons of utilization between different systems or groups of systems with vastly different generating capacities, or even with different technology and fuel types.

Three examples of different customer operating characteristics and their impact on DG utilization are shown in Figure 4-3.

Figure 4-3: Customer Needs, DG Utilization, and Capacity Factor



(a) ***Baseload operation at a datacenter***

(b) ***Load following at an agricultural site***

(c) ***Load following at a high school***

Figure 4-3 (a) shows the hourly electrical utilization of an electric only fuel cell installed at a data center. The data center has a continuous demand for electricity. Consequently, the SGIP project is operated continuously to serve the electrical load. This type of project is most commonly referred to as a baseload system.

The electrical utilization of a DG system installed at an agricultural site is shown in Figure 4-3 (b). DG system utilization at agricultural and industrial facilities is closely tied to the schedule of energy intensive processes on-site. Generation at the agricultural site shown in Figure 4-3 (b) appears to be ramping up and down to match the host customer's electrical demand. This type of operation is known as load following. A DG system may cycle to follow either an electrical load or a thermal load.

Another example of load following at a high school is shown in Figure 4-3 (c). In this case, the DG operator at the high school has decided not to operate the system during weekday afternoons and weekends.

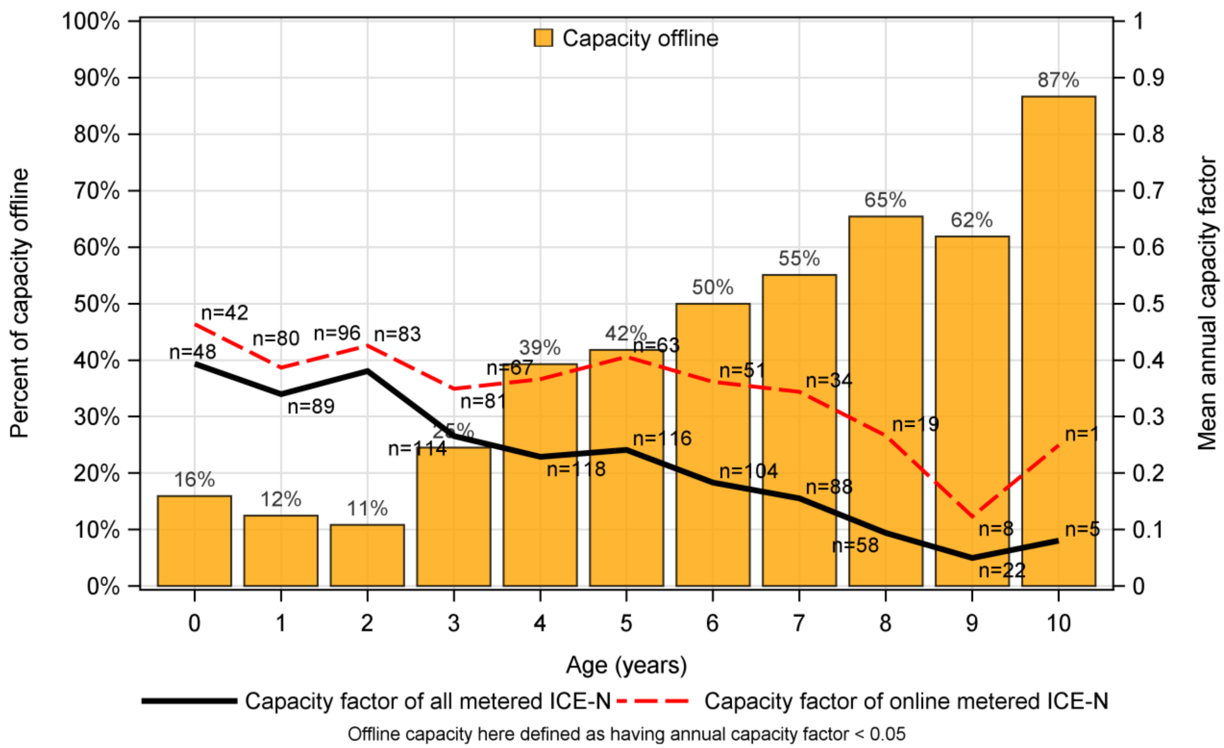
Since SGIP systems are designed to satisfy the energy needs of the customer, electricity output from any one system may be strongly affected by the customer's electrical load. The different operating schedules of several hundred SGIP systems in turn influence the program-level output during any hour. Understanding the hourly electrical demand of a host customer is critical when sizing and scheduling DG operation. Fuel cells and gas turbines tend to be utilized in baseload operating modes while internal combustion engines and microturbines can more readily operate in load following mode.

Changes in the SGIP Fleet Composition

The SGIP represents a mix of projects that is more than ten years old. With new projects being completed each year, the composition of the SGIP is constantly changing. At the same time, some of the oldest SGIP projects are now in their eleventh year of operation. As projects age, there is an increase in the incidence of maintenance issues and the probability of system decommissioning. Consequently, capacity factors tend to decrease as project age increases.

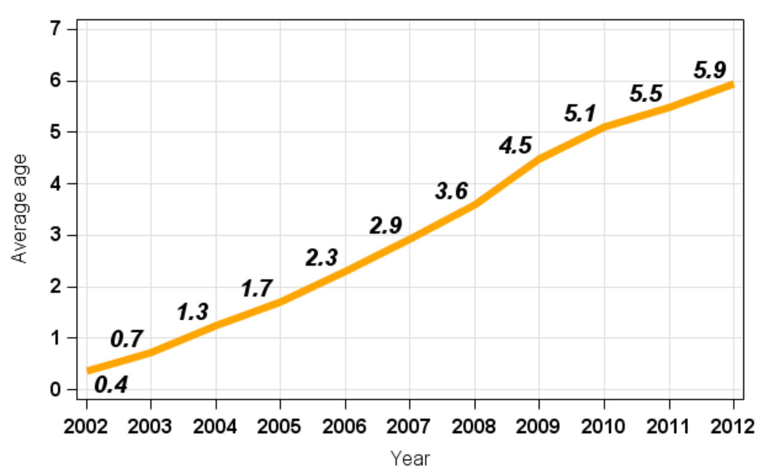
To illustrate the effect of project age on capacity factor, Figure 4-4 shows internal combustion engine capacity factors and the percent of internal combustion engine capacity retired or temporarily offline associated with system age.

Figure 4-4: Effect of Age on Internal Combustion Engine Capacity Factors



Older internal combustion engines tend to be offline a greater percent of the time than newer internal combustion engines. Almost 90% of the oldest internal combustion engines are offline, compared to only 16% of brand new internal combustion engines. Furthermore, capacity factors for new internal combustion engines are four times greater than capacity factors for ten-year-old internal combustion engines. Put differently, new internal combustion engines are utilized four times more than the oldest internal combustion engines. While lower capacity factors are not necessarily good or bad, in this case they appear to be a sign of aging and degradation.

Figure 4-5: The Aging of SGIP Projects



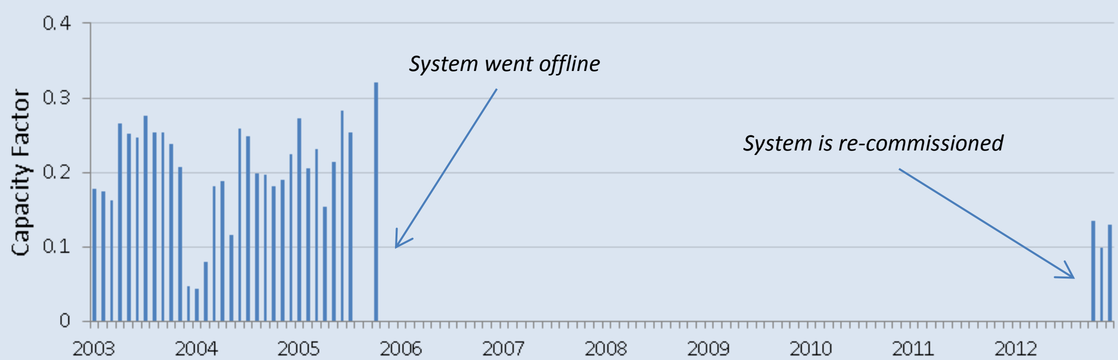
The average age of SGIP projects is

increasing over time. Figure 4-5 shows that the average age of an SGIP project has increased from 0.4 years in 2002 to almost six years in 2012. As projects age they require more maintenance to remain operational. In some cases the maintenance costs are too high and host customers opt to decommission DG systems. Furthermore, the economics for certain host customers might change over time and operation of a perfectly functional DG system may no longer be feasible. By the end of 2012, 65 MW (23%) of the SGIP's rebated capacity was either retired or temporarily offline.

SGIP Project Recommissioning: A Case Study

In 2003, a 600 kW project was issued its SGIP incentive, marking the completion of the project. This SGIP project was installed at a large commercial building and used an absorption chiller to deliver both hot and cold water to the building. The project operated continuously at a relatively low capacity factor from 2003 until 2006. After 2006, the system owner decided to stop operating the engine. The system remained offline for almost seven years until a third party took ownership of the system and re-started operations.

During the last quarter of 2012, this project has operated continuously at a capacity factor of 0.1 or greater. While this capacity factor is relatively low, the system recommissioning was responsible for over 160 MWh of electrical impacts that are attributed to the SGIP during 2012.



Policy and Regulatory Changes

Besides age and operating schedules, regulations and policies also affect SGIP impacts and capacity factors. For example, increasingly strict air quality standards for non-renewable internal combustion engines taking effect in 2008 may have contributed to the largest observed increase in retirement of SGIP capacity. South Coast Air Quality Management District (SCAQMD) Rule 1110.2 required operators of permitted non-renewable internal combustion engines in SCAQMD territory to take new actions starting August 1, 2008. Additional operational costs related to specific emissions limits and mandated inspection, monitoring, and reporting requirements may have made operation uneconomic for some SGIP hosts with internal combustion engines.

Future Outlook

In recent years, the SGIP has made significant changes to its program rules. These rules were in part designed to maximize the electrical impacts of the program. As an example, under the new program rules non-renewable CHP projects larger than 30 kW will be penalized if their annual capacity factor falls below 0.8. Furthermore, warranty requirements were extended to ten years to ensure that maintenance costs are covered throughout the life of the program. These two program changes will ensure that new projects entering the program operate as close as possible to their theoretical maximum capacity factor.

However, the vast majority of the SGIP's rebated capacity consists of "legacy" projects that are not subject to the new program rules. The SGIP legacy projects are generally older and some have already been decommissioned. As time goes on, an increasing proportion of the SGIP legacy fleet will be decommissioned.

Future SGIP electrical impacts will reflect the combined impacts of legacy projects and newer projects. All other things equal, in order for the SGIP to achieve higher capacity factors, the rate at which new projects enter the program must exceed the rate at which older projects go offline.

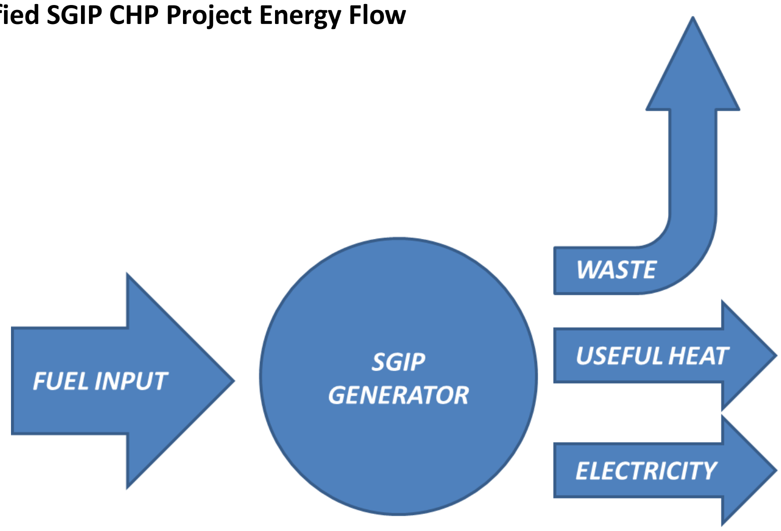
Key Takeaways:

1) ***SGIP projects generated 970 GWh of electricity in 2012.***
2) ***Capacity factors were relatively high for fuel cells and gas turbines. Internal combustion engines and microturbines achieved lower capacity factors.***
3) ***The average age of SGIP internal combustion engines has increased from 0.4 years in 2002 to almost 6 years in 2012 – older projects have a greater tendency to be offline.***
4) ***Re-commissioning of idle systems may offer a means of recovering additional value from 65 MW of SGIP capacity that was retired or temporarily offline at the end of 2012.***

4.3 Efficiency and Waste Heat Utilization

SGIP projects convert fuels such as natural gas and renewable biogas into electricity and heat. Certain CHP technologies are designed to recover some of this heat and utilize it to serve an on-site thermal load. Other technologies utilize all available energy internally and have no heat available for recovery. Heat that is not recovered on-site is dissipated as waste heat.

Figure 4-6: Simplified SGIP CHP Project Energy Flow



The following topics and their relationship to SGIP energy impacts are discussed in this section:

- *Fuel types and observed electrical conversion efficiency*
- *Thermal end uses and observed heat recovery rate*
- *Overall system efficiency*

The following definitions of electrical conversion efficiency (ECE), heat recovery rate (HRR), and overall system efficiency (EFF) are used throughout this section.

$$ECE = \frac{\text{Electrical Output}}{\text{Fuel Input}} \; [\,] \qquad HRR = \frac{\text{Waste Heat Recovered}}{\text{Electrical Output}} \; [MBtu/kWh]$$

$$EFF = \frac{\text{Electrical Output} + \text{Waste Heat Recovered}}{\text{Fuel Input}} \; [\,]$$

Note that the electrical conversion efficiency and system efficiency are unit-less values, whereas the heat recovery rate is not.

Fuel Types and Electrical Conversion Efficiency

SGIP systems consume either non-renewable natural gas or renewable biogas to generate electricity. Renewable biogas may be produced and consumed on-site or produced at a remote location and notionally delivered on-site in the form of 'directed biogas.' SGIP system counts and capacities are shown in Table 4-4 distinguished by these three fuel types.

Table 4-4: SGIP System Counts and Capacities by Fuel Type[7]

Fuel Type	*System Count*	*Rebated Capacity (MW)*	*Percent of Total Capacity*
Natural Gas	475	219.4	78%
On-Site Biogas	66	33.1	12%
Directed Biogas	60	29.8	11%
TOTAL	**601**	**282.3**	**100%**

More than three-quarters of the 2012 SGIP rebated capacity uses non-renewable natural gas to fuel their generators. The remaining 22% of SGIP capacity is fueled by renewable biogas.

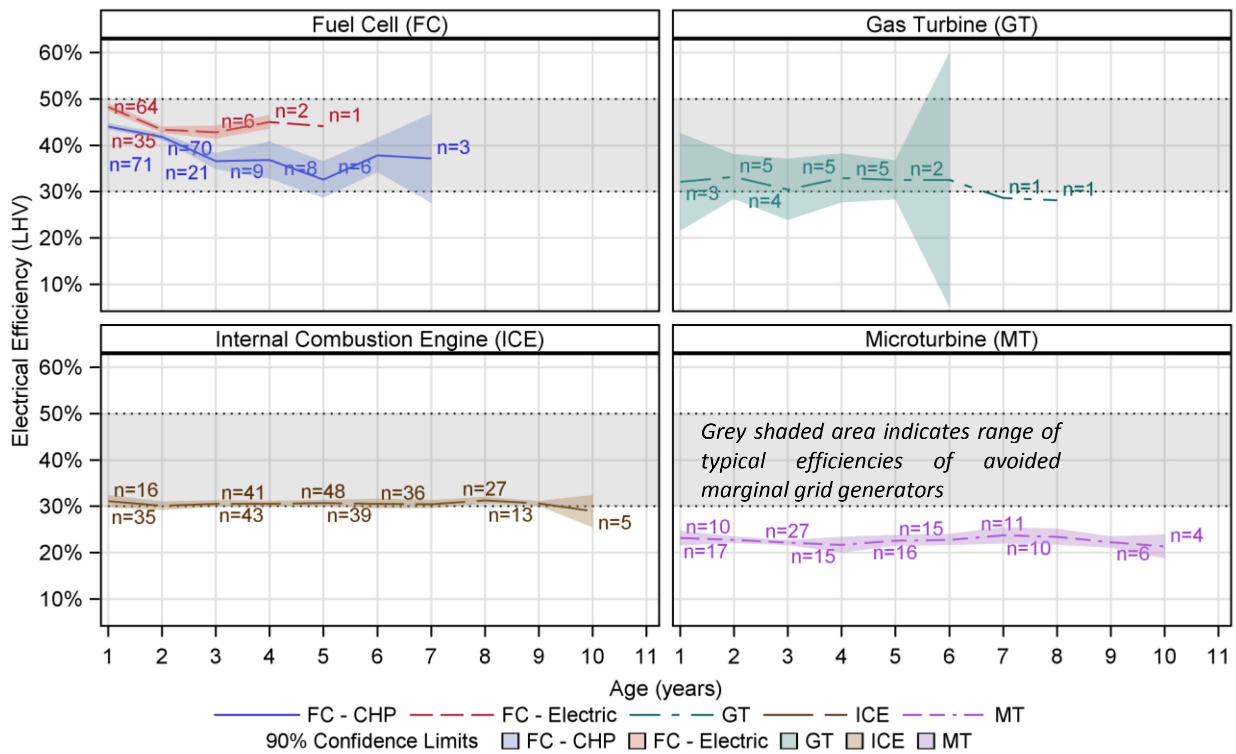
Not all technologies are made equal. Technologies such as fuel cells are more efficient at converting fuel into electrical energy than microturbines. A system's ability to convert fuel into electricity is defined as the electrical conversion efficiency. A system's electrical conversion efficiency is a number between zero and one that describes how much electricity is obtained from the system for a unit of fuel input. A system with a higher electrical efficiency can extract more energy from the same amount of fuel than a system with a lower electrical efficiency. As with a vehicle's fuel economy rating, a vehicle with a higher

[7] On-site biogas projects include systems that blend renewable biogas with natural gas.

MPG rating can go further on a tank of gas. The electrical efficiencies observed in 2012, along with trends in efficiencies as a function of system age are shown in Figure 4-7. The following general observations can be made:

- *Electrical efficiencies for gas turbines (GTs), internal combustion engines (ICEs), and microturbines (MTs) have remained generally constant over time*
- *Electrical efficiencies for fuel cells (FCs) appear to degrade in the first years of operation but then remain flat over time*
- *Electric-only fuel cells (FC – Electric) have the highest average electrical efficiency in the SGIP while microturbines have the lowest average electrical efficiency*

Figure 4-7: Electrical Efficiencies Observed by Year of Operation



	FC – CHP	*FC – Electric*	*GT*	*ICE*	*MT*
2012 Weighted Average Electrical Efficiency (Lower Heating Value)	38%	47%	33%	31%	23%

The SGIP fleet at 2012 is composed of systems aged 1 to 10 years. Combustion based technologies (gas turbines, internal combustion engines, and microturbines) show very minor effects of aging in their electrical efficiencies. In other words, as combustion systems have aged, their electrical efficiencies have not changed substantially. Fuel cells, particularly those that recover useful waste heat, exhibit greater variability in their electrical efficiency as a function of age. The reason for this variability may be due to degradation effects in the fuel cell stack.

Electric-only fuel cells had the highest observed electrical efficiency at 47% lower heating value (LHV) (42 percent higher heating value[8] (HHV)). Combustion technologies had lower electrical efficiencies: microturbines had the lowest electrical efficiencies observed in 2012 with 23% lower heating value (21% higher heating value). Lower electrical efficiencies result in greater fuel consumption required to meet the same electrical load.

Also shown in Figure 4-7 is the typical range of central station generator Lower Heating Value efficiencies whose operation is avoided when SGIP systems supply electricity to meet customer needs. This range is shown as the grey band in each quadrant. Combustion technologies achieve electrical efficiencies close to the least efficient central station generators. Fuel cells achieve higher electrical efficiencies. The relationship between the electrical efficiencies of SGIP technologies and avoided grid generators has important implications for greenhouse gas impacts. This relationship is explored in more detail in Section 6.

Thermal End Uses and Heat Recovery Rate

Figure 4-7 describes the relationship between the amount of fuel that enters an SGIP system and the amount of electricity that is generated. Not all of the energy that enters a generator in the form of fuel is converted into electricity. The energy that is not converted into electricity is dissipated as heat. Certain technologies are capable of capturing this heat and using it to serve on-site loads. The distribution of end uses served by capturing useful waste heat is summarized in Table 4-5. The end use of the recovered waste heat, either heating or cooling, has important implications for achieving greenhouse gas emission reductions.

Table 4-5: Distribution of Waste Heat End Uses

Waste Heat End Use	*Project Count*	*Rebated Capacity (MW)*	*Percent of Total Capacity*
Heating	368	129.3	46%
Cooling	39	33.5	12%
Heating and Cooling	87	68.8	24%
Not Required	105	50.3	18%
Unknown	2	0.4	0%
TOTAL	**601**	**282.3**	**100%**

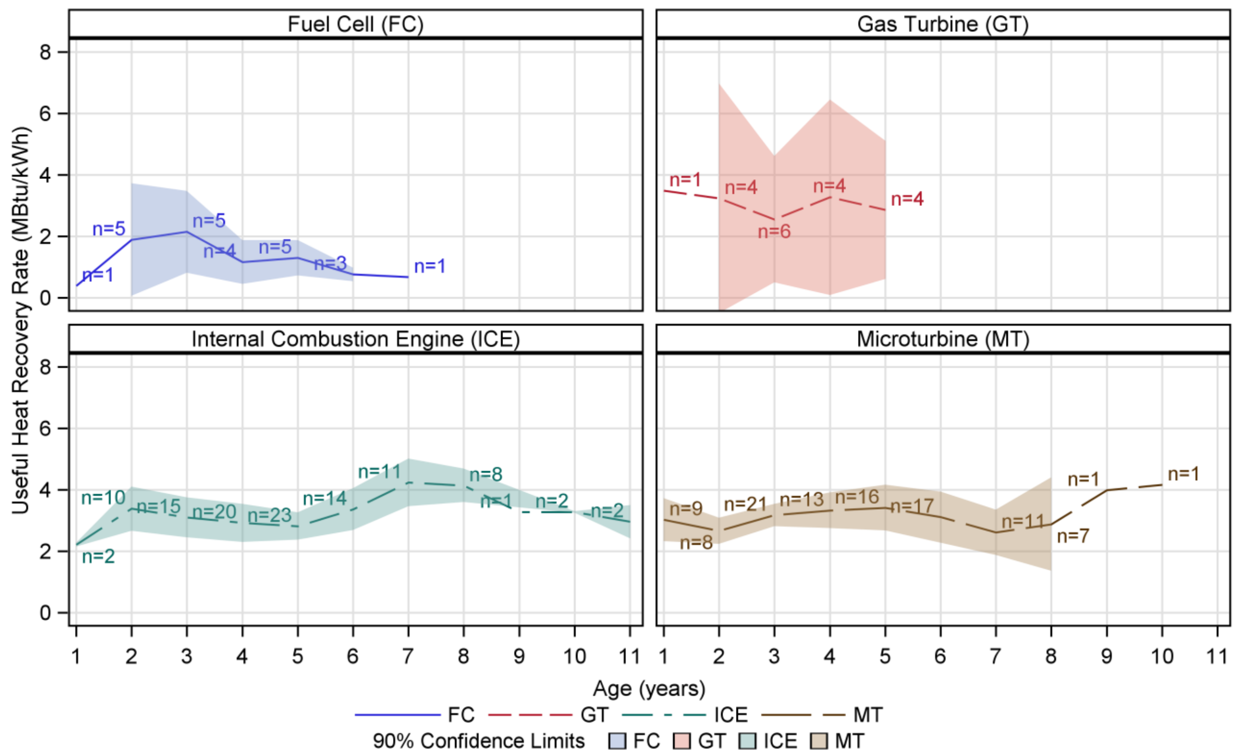
About one-fifth of the SGIP's capacity is not required to recover waste heat because it is either fueled by renewable biogas or is otherwise exempt from heat recovery requirements. The remaining 496 projects recover waste heat to serve an end use.

[8] Higher heating value assumes 1,020 Btu of chemical energy per cubic foot of natural gas.

Almost half of SGIP capacity recovers waste heat to serve a heating end use exclusively. These systems typically displace heat that would otherwise have been generated by on-site boilers fueled by natural gas. Twelve percent of SGIP capacity use recovered heat in an absorption or adsorption chiller to serve a cooling load. In the absence of the program, the cooling load would have been served by an electric chiller.

The useful heat recovery rate (HRR) describes the amount of useful heat that is recovered per unit of electricity generated. Unlike an efficiency value, the useful heat recovery rate may be greater than one. The useful heat recovery rates observed, along with trends in useful waste heat recovery rates as a function of system age are shown in Figure 4-8.

Figure 4-8: Useful Waste Heat Recovery Rates Observed by Year of Operation



	FC – CHP	*GT*	*ICE*	*MT*
2012 Weighted Average HRR [MBtu/kWh]	1.13	3.52	3.69	3.66

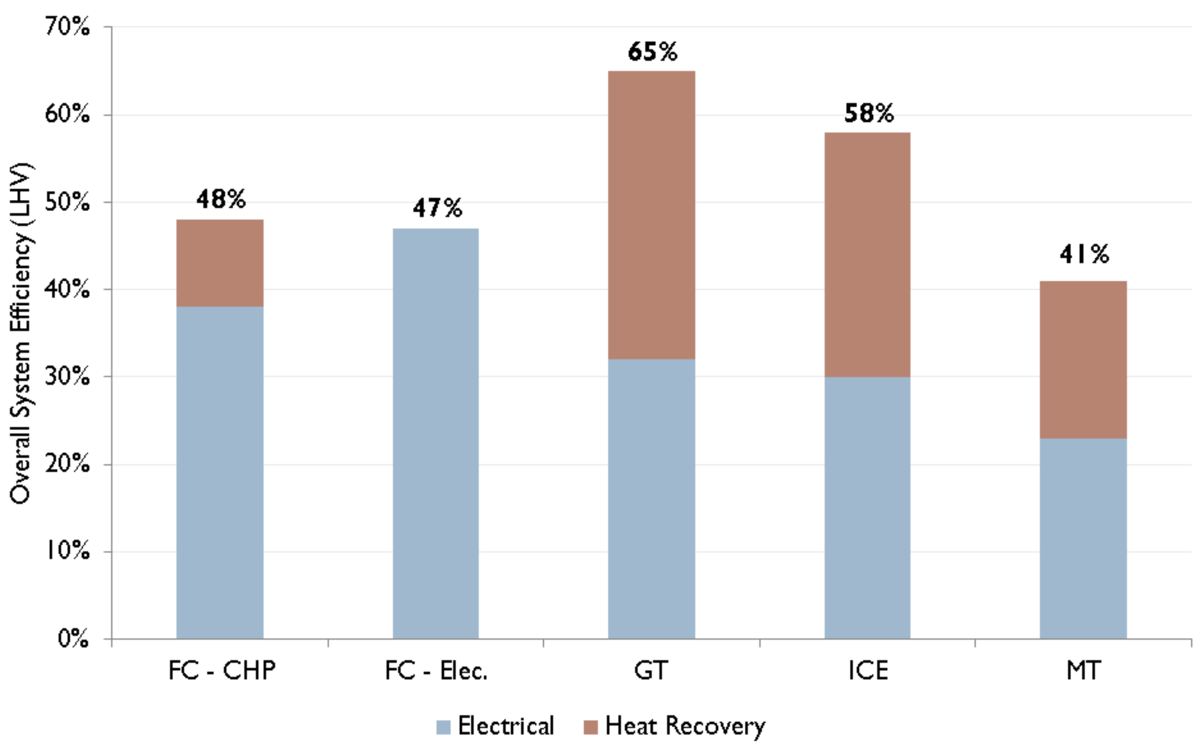
Fuel cells have the lowest observed useful waste heat recovery rates in 2012 with an average of 1.13 MBtu / kWh.[9] Combustion technologies all achieved a useful waste heat recovery rate between 3.5 – 3.7 MBtu / kWh.

Overall System Efficiency

Technologies with higher electrical efficiencies have less waste heat available to recover. Consequently, technologies such as fuel cells that achieve high electrical efficiencies are expected to achieve lower useful waste heat recovery rates. On the other hand, technologies with lower electrical efficiencies such as microturbines and internal combustion engines generate more heat and are expected to achieve higher useful heat recovery rates.

The overall system efficiency accounts for both electrical energy and useful heat recovery, which allows for an 'apples to apples' comparison of technologies. System efficiencies observed in 2012 are shown in Figure 4-9.

Figure 4-9: Overall System Efficiency Observed in 2012



Gas turbines have the highest observed overall system efficiency at 65%, followed by internal combustion engines at 58%. Microturbines have low electrical efficiencies and low heat recovery rates, resulting in an average system efficiency of 41%.

[9] MBtu/kWh refers to thousands of Btu of recovered heat per kilowatt-hour of generated electricity

Key Takeaways:

1) ***Electrical efficiencies of combustion technologies have remained flat as systems age while fuel cell efficiencies have exhibited greater variability.***
2) ***Heat recovery rates remain below theoretical maximums.***
3) ***Gas turbines achieved the highest overall system efficiencies while microturbines continue to be the least efficient SGIP technology.***

4.4 Future Energy Impacts Including Capacity in the Queue

The SGIP currently is set to sunset at the end of 2015. To provide an outlook on the program's ability to deliver energy impacts in the future, post-2012 impacts are estimated from a combination of the SGIP's existing capacity,[10] technology portfolio, and the capacity portfolio in the current queue of reserved projects. Table 4-6 lists the current SGIP queued capacity by technology and fuel. It also lists assumed annual capacity factors for each technology and fuel.

Table 4-6: Program Queue as of April 12, 2013

Technology / Fuel	*Queued Capacity (MW)*	*Assumed Annual Capacity Factor*
Alternative Energy Storage	**27.0**	
n/a	27.0	n/a
Fuel Cell (Electric Only)	**45.3**	
Natural Gas	45.0	0.80
Directed Biogas	0.3	0.80
Fuel Cell (CHP)	**2.9**	
Natural Gas	2.9	0.80
Gas Turbine	**18.0**	
Natural Gas	18.0	0.80
IC Engine	**21.7**	
Natural Gas	8.1	0.80
Biogas (Flare)	13.6	0.70
Microturbine	**6.9**	
Natural Gas	4.8	0.80
Biogas (Flare)	2.1	0.70
Wind	**18.9**	
n/a	18.9	0.25
TOTAL	**140.7**	

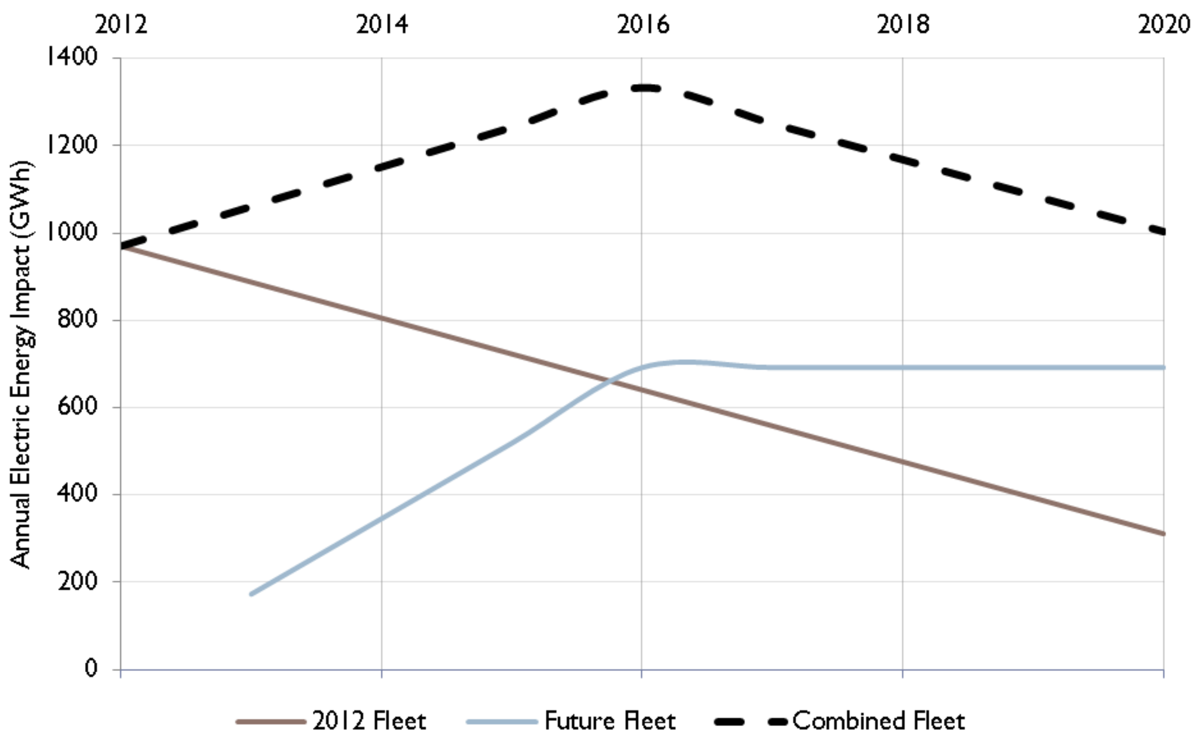
[10] This excludes all existing Wind and Photovoltaic capacity.

Rather than speculate how the current queue may come to be fulfilled or change with time, the entire 141 MW of capacity in the current queue is added to the existing SGIP fleet of projects. Annual capacity additions are assumed to consist of 25% of the capacity from each row of Table 4-6 resulting in equal capacity additions each year through 2016.[11] Building out the queue in this way represents a growth in capacity of 35.2 MW each year. As such, this is an aggressive growth rate given only 2003 and 2004 have greater capacity additions.

Projected energy impacts explicitly assume output from existing SGIP capacity to decline at historically observed rates by technology and fuel type. Output from new capacity from the queue, on the other hand, is assumed to begin with and to maintain levels of output described by the annual capacity factors in Table 4-6. For example, non-renewable CHP is assumed to maintain the 0.80 minimum annual capacity factor required for maximum PBI payment.

The projected annual energy impacts of the existing SGIP capacity fleet at the end of 2012 and of the assumed future capacity fleet are shown as brown and blue solid lines in Figure 4-10. A dashed black line shows the sum of these impacts.

Figure 4-10: 2012 and Projected Annual Electric Energy Impacts through 2020



The future fleet has energy impacts increasing each year with the addition of new capacity. The 2012 fleet has energy impacts declining each year as more capacity is retired or is simply generating at lower levels. The future fleet lifts the combined annual energy impact from 970 GWh in 2012 to a peak of

[11] Even though the SGIP ends on December 31, 2015, projects are assumed to reach a complete status during 2016, thereby increasing the program's rebated capacity in 2016.

1,330 GWh in 2016. From 2017 to 2020, impacts decline along with declines of the 2012 fleet. The future fleet is assumed to maintain impacts after 2016 due to more stringent warranty requirements and the PBI incentive structure.

Future fuel consumption and useful heat recovery impacts are projected using a similar approach to future electrical energy impacts. Historically observed electric conversion efficiencies and useful heat recovery rates are combined with electricity impacts to estimate fuel and heat impacts. Projected fuel consumption impacts rise and fall in the same manner as the electrical energy impacts. Fuel consumption is projected to peak at over 99 million Therms in 2016 and taper down thereafter due to degradation in the existing fleet. The projected useful waste heat recovered exhibits similar behavior peaking at almost 2.3 billion Btus in 2016.

Key Takeaways:

1) ***If all the contents of the queue enter the program by 2016, SGIP generation is projected to peak at 1,330 GWh in 2016.***

2012 Peak Demand Impacts

5

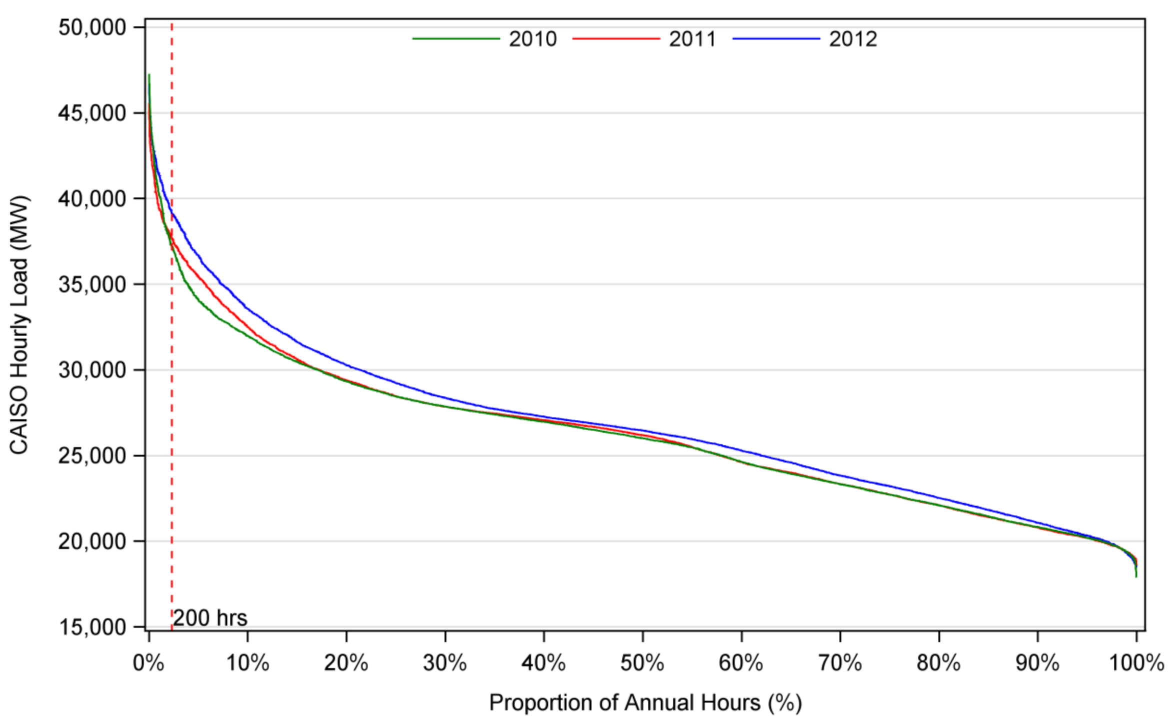
5 2012 SGIP PEAK DEMAND IMPACTS

Peak demand impacts result from the generation of Self-Generation Incentive Program (SGIP) projects during peak periods.[1] This on-site generation decreases reliance on the grid when it is most congested, typically during hot weekday afternoons between May and September. This section describes SGIP peak demand impacts across the statewide grid - managed by the California Independent System Operator (CAISO) as well as across the grids of the three investor-owned electric utilities (IOU). This section further examines the impacts during the CAISO peak and the average impact during the top hours of CAISO demand and identifies the average impacts during the top hours of demand for the three IOUs. Finally, this section estimates the financial value of peak demand impacts during the top hours of IOU demands.

5.1 CAISO Impacts

Peak demand periods represent a small portion of a year, the bulk of electricity usage being off-peak. Figure 5-1 shows proportions of annual hours at different CAISO hourly loads for 2010 through 2012. Generally, the highest loads occur in just 200 hours; less than 2.3% of the year.[2] For purposes of this report, peak periods include the 200 hours shown to the left of the red dashed line in Figure 5-1.

Figure 5-1: CAISO Load Duration Curves (2010-2012)



[1] SGIP wind and alternative energy storage (AES) systems are not included in any values described in this section due to a lack of metered data.

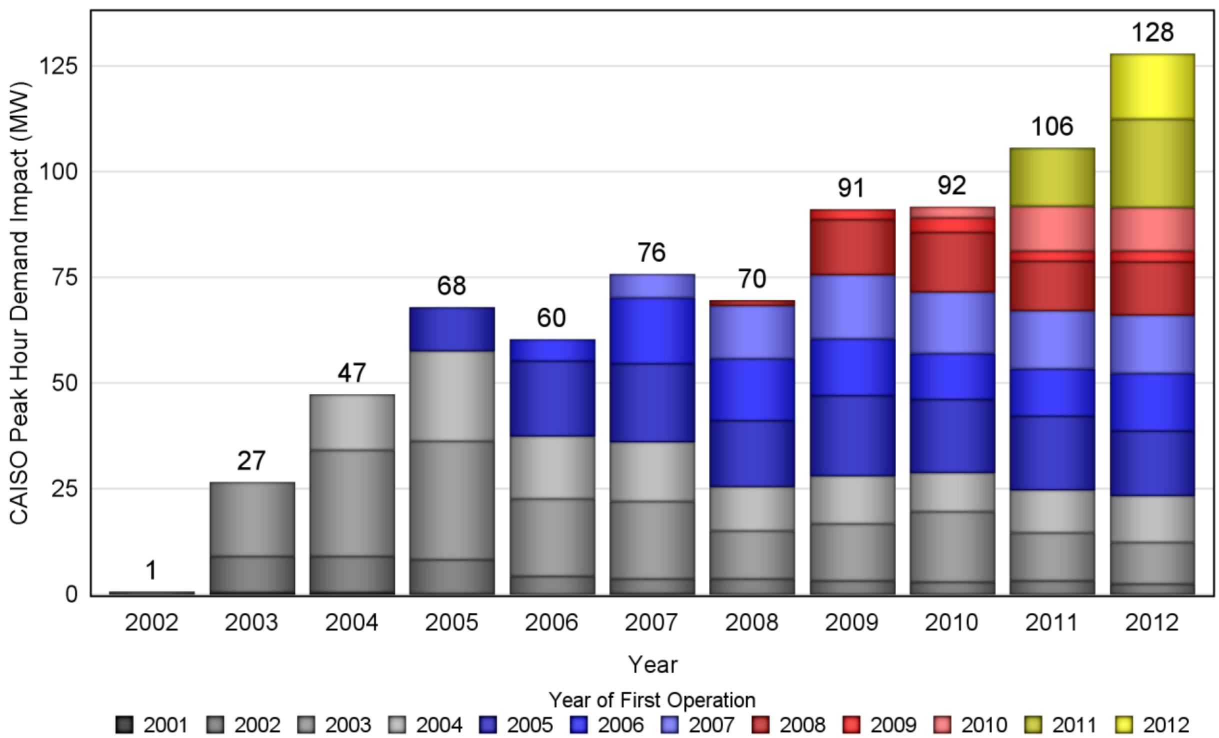
[2] An additional 10% of generation capacity is needed to meet those few hours of peak demand.

Impacts observed during the CAISO peak and top 200 load hours are important metrics for determining the SGIP's success in reducing peak demand. The SGIP's impact during the peak hour is described below, followed by impacts during the top 200 hours.

Peak Hour Demand Impact

The impact from SGIP capacity is estimated to be 128 MW during the CAISO peak. The 2012 peak hour occurred from 4 to 5 p.m. Pacific Daylight Time on Monday, August 13, when the average demand was 46,682 MW. Figure 5-2 shows the 2012 peak impact of 128 MW along with impacts in earlier years.

Figure 5-2: CAISO Peak Hour Demand Impacts, 2002 through 2012



The color bands of Figure 5-2 indicate impact contributions based on the year when projects first came online. The two yellow bands atop the 2012 impact indicate the contributions from the SGIP 'vintages' of 2011 and 2012. The contributions from all earlier vintages have remained flat at about 92 MW since 2009.

The 2012 impact of 128 MW represents an increase of 22 MW from the 106 MW of 2011. This large increase is primarily a result of over 54 MW of new projects added between 2011 and 2012. Capacity additions occur each year, but do not necessarily lead to increases in demand impacts.

Figure 5-2 also shows decreased impacts in 2006 and 2008. In 2006 and 2008 natural gas prices rose, causing increases in the cost of generation. These cost increases are likely behind the declines in SGIP capacity utilization and demand impacts, though determining causal inference would require further investigation.

In 2008, capacity utilization also fell among non-renewable internal combustion (IC) engines in the South Coast Air Quality Management District, a result believed to be due to an emissions rule change as described in Section 4. Utilization of this capacity remains very low and much of it is known to be retired. Such capacity retirement is apparent in Figure 5-2. The shrinking gray bands illustrate declining peak demand impacts in later years due to aging and retirement of projects added in earlier years. In 2012, impact contributions from the vintages of 2004 and earlier are less than half what they were in 2005.

A number of SGIP projects are retired or temporarily offline. Eighty-seven MW of projects, or 31% of the total SGIP capacity, is estimated to be either retired or temporarily offline as of the end of 2012. These projects contribute no peak demand or other impacts. For that reason, the maximum theoretical capacity online during the 2012 peak hour is limited to approximately 189 MW.

The 128 MW impact represents just 0.3% of the 2012 CAISO peak. This is not unexpected given the SGIP's total capacity of 282 MW is just 0.4% of the combined capacity of in-state power plants. However, if ranked as a single power plant, the SGIP's total capacity is still significant: It would rank 52nd among the 1,144 in-state power plants, whose combined capacity is 71 GW.[3] In turn, this "SGIP power plant" would be contributing 128 MW (over 45% of its total capacity), helping to reduce peak demand at the time most needed by California's electricity system.

In reality, the SGIP fleet behaves quite differently from a single power plant. Not only is the SGIP capacity distributed among hundreds of projects, but as Figure 5-2 shows, it is also multi-generational. That is, the SGIP's total capacity is composed of many systems ranging in age from several months up to 11 years. In addition, these projects are not all utilized during the peak hour. Moreover, those projects that are utilized do not all generate at their full nameplate capacities. If all capacity were utilized at full nameplate capacity the 2012 demand impact would have been 276 MW during the peak hour.[4]

SGIP capacity is composed of multiple technologies and fuels. Figure 5-3 shows contributions to the 128 MW demand impact from these seven technology and fuel types.

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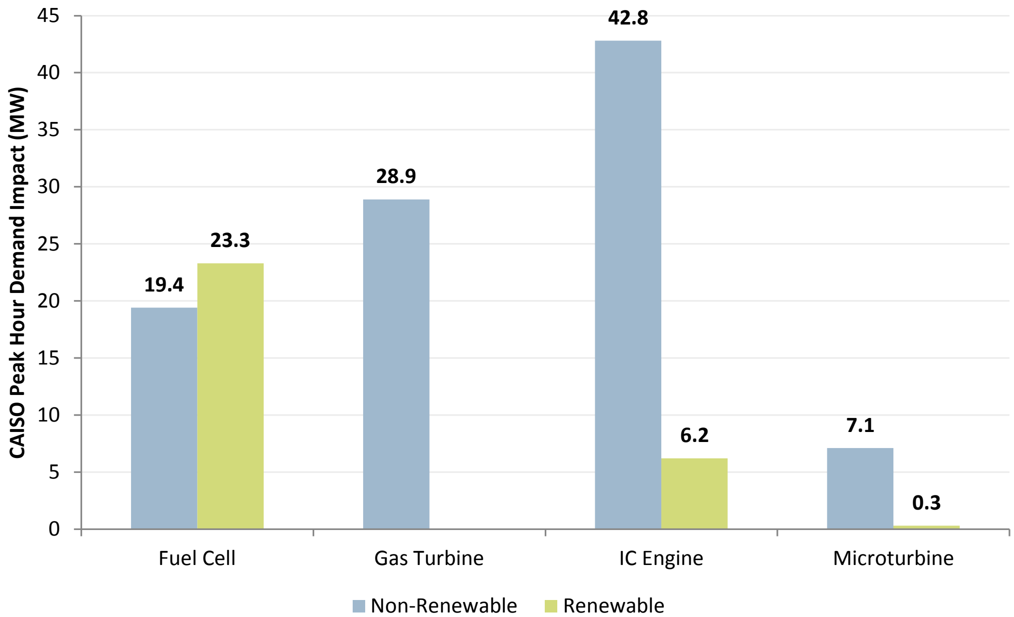
[3] Based on the California Energy Commission (CEC) list of power plants available at http://www.energyalmanac.ca.gov/powerplants/Power_Plants.xlsx

[4] The total SGIP capacity by the end of 2012 (282 MW) was greater than the installed capacity during the CAISO peak hour (276 MW). Six MW were added to the 276 MW between the CAISO peak hour and the end of 2012.

Figure 5-3: CAISO Peak Hour Demand Impacts by Technology and Fuel Type



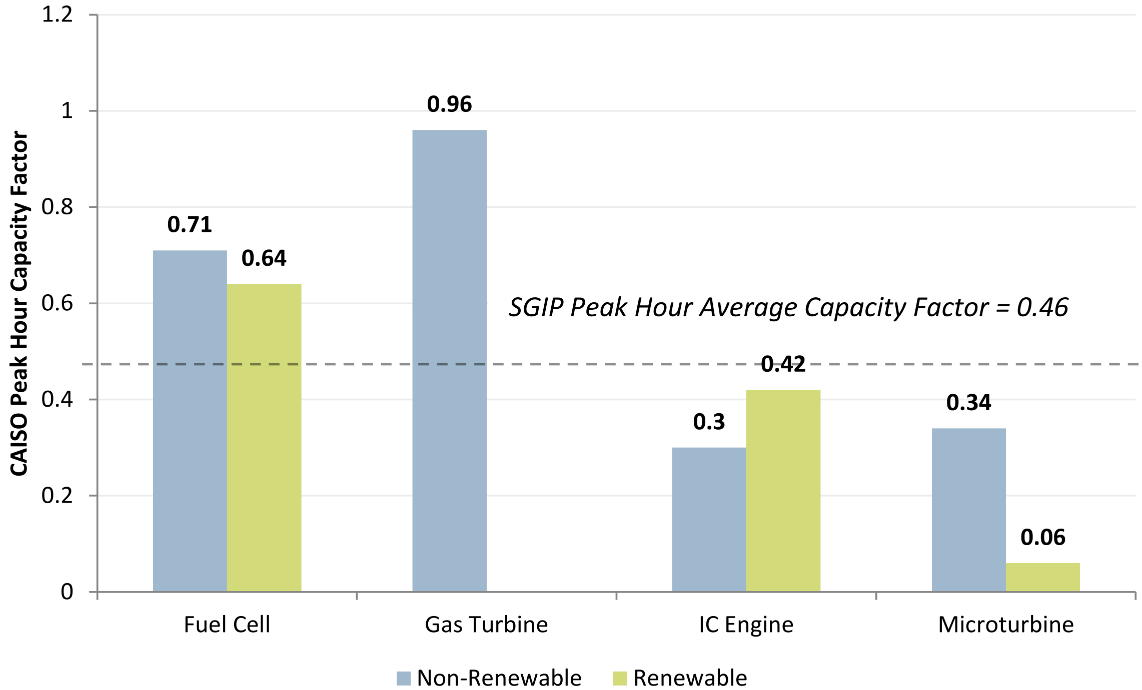
The differences in impact contributions by technology and fuel type shown in Figure 5-3 are due primarily to differences in the capacities. As described in Section 3, capacity is greatest among non-renewable internal combustion engines. Renewable fuel cell capacity is a distant second followed by similar capacities for non-renewable gas turbines and non-renewable fuel cells. The greater capacities of these technologies and fuel types largely explain their greater demand impacts.

Impact contributions by technology and fuel type also differ due to differences in their average capacity utilization. As noted in Section 4, utilization is described in terms of capacity factor. Utility customers using fuel cells or gas turbines tend to operate their systems with high capacity factors during all hours of the week. Many fuel cells require such operation to maintain high system temperatures. SGIP gas turbines typically operate with high capacity factors 24/7. Program participants using other DG technologies tend to have more variable capacity factors and schedules. These schedules sometimes include off-line hours during weekends or evenings during which capacity factor is zero. During weekday afternoons in the summer, SGIP systems may be operated well below the capacities of their systems to avoid exporting electricity to the grid.

The same general age effects that were discussed for annual energy impacts in Section 4 also influence demand impacts. To demonstrate the implications for demand impacts of capacity utilization we contrast technology and fuel types by capacity factor. Figure 5-4 shows their average capacity factors during the CAISO peak demand hour.[5] It also includes a reference line showing program total capacity factor of 0.46.

[5] Averages by technology and fuel type here are weighted averages with weight defined by system capacity in kW.

Figure 5-4: CAISO Peak Demand Hour Average Capacity Factor by Technology and Fuel Type



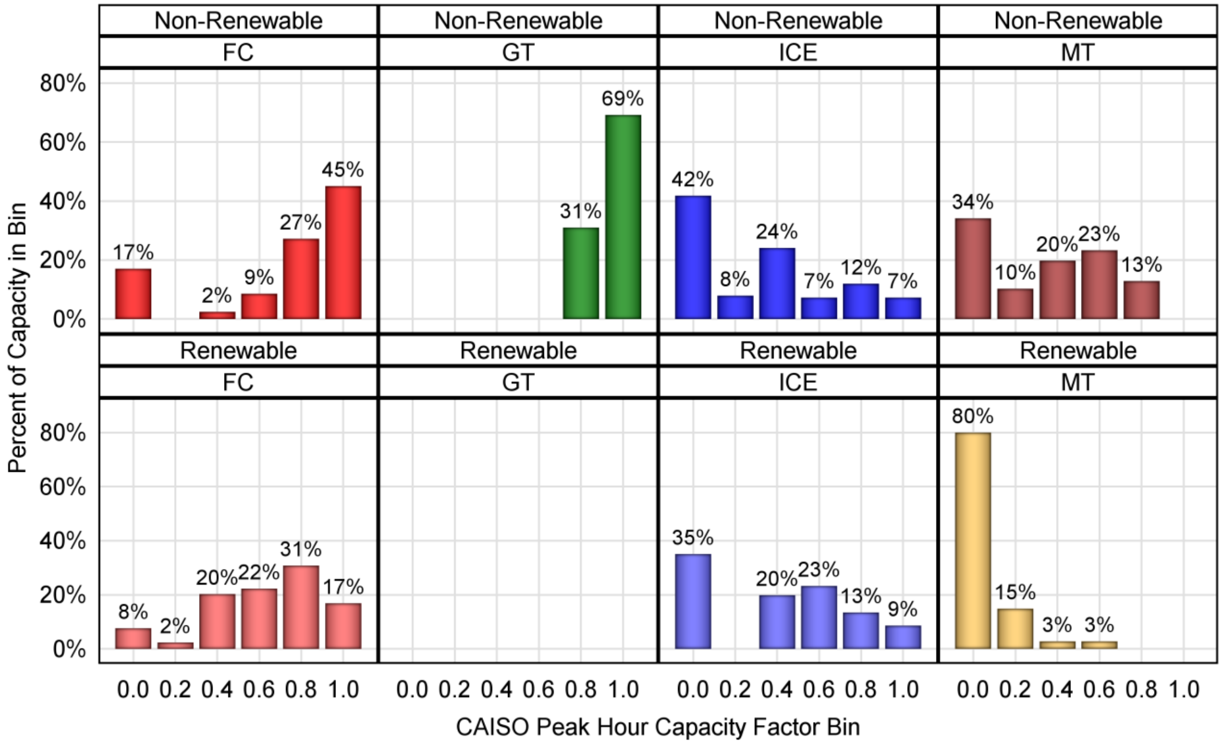
The high capacity factor for non-renewable gas turbines results in their accounting for the second largest portion of demand impacts, despite representing only 10% of program capacity. Non-renewable and renewable fuel cells also had high capacity factors that explain large demand impacts despite representing just 10% and 13% of program capacity, respectively.

Non-renewable internal combustion engines on the other hand have the second lowest capacity factor. Nevertheless, they account for 51% of the program capacity and have the greatest demand impact. Their low capacity factor is due largely to old age relative to other technology and fuel types.

Internal combustion engines and microturbines do not inherently have lower capacity factors than gas turbines and fuel cells during peak periods. It is a utility customer's generation schedule, rather than a system's technology, that determines capacity factor during peak periods. Generation schedules can depend on more than electric demand: Where useful heat recovery influences operational economies, generation schedules depend on both electrical and thermal demands. If electrical and thermal demands both are high during peak periods, the capacity factor is also likely to be high. If thermal demand is low, the capacity factor may also be low.

Average capacity factors mask the variability exhibited by individual systems. Capacity factor diversity arises from differences in system ages, generation schedules and levels, technology and fuel types, and in some cases from changing air quality regulations. Figure 5-5 demonstrates capacity factor variability between and within technology and fuel types during the CAISO peak.

Figure 5-5: CAISO Peak Hour Capacity Factors and Capacity Percentages



The vertical bars of Figure 5-5 indicate the percentage of the technology and fuel type's capacity with capacity factor in a capacity factor bin. The bin labeled '0.0' includes systems with capacity factor less than 0.1; bin '1.0,' with capacity factor equal to or greater than 0.9. All other bins are 0.2 units wide. For example bin '0.6' includes capacity factors from 0.5 through 0.699.

The majority of internal combustion engines and microturbines have capacity factors in bin 0.4 or lower. Most internal combustion engine and microturbine systems are quite old, and these technologies are more frequently observed operating at lower capacity factors. Figure 5-5 shows no microturbines in capacity factor bin 1.0. Some internal combustion engine capacity is in bins 0.8 and 1.0 and some non-renewable microturbine capacity is in bin 0.8. Systems with either of these technologies can deliver demand impacts like that of gas turbines and fuel cells despite the fact that many do not.

It is important to note that as systems age they do not necessarily operate at ever lower capacity factors. Some older SGIP projects continue to operate with high capacity factors. In fact, some older SGIP projects actually increase capacity factor over time. Metered data revealed a number of older SGIP systems that had been recommissioned. While new capacity additions generally increase SGIP demand impacts, retired systems that are recommissioned can do the same. The cost of recommissioning is lower than the original capital investment of the project. As such, there may be economic opportunities associated with recommissioning older SGIP systems that leads to future increased energy and peak demand impacts. Private investment in recommissioning SGIP capacity thought to be retired represents a new market effect for consideration in determining the program's impact on market transformation.[6]

Top 200 Demand Hours

As a more robust measure of SGIP peak demand impacts we consider additional peak demands besides the single peak hour. Specifically, we consider the top 200 CAISO demands as shown in the load duration curve of Figure 5-1.

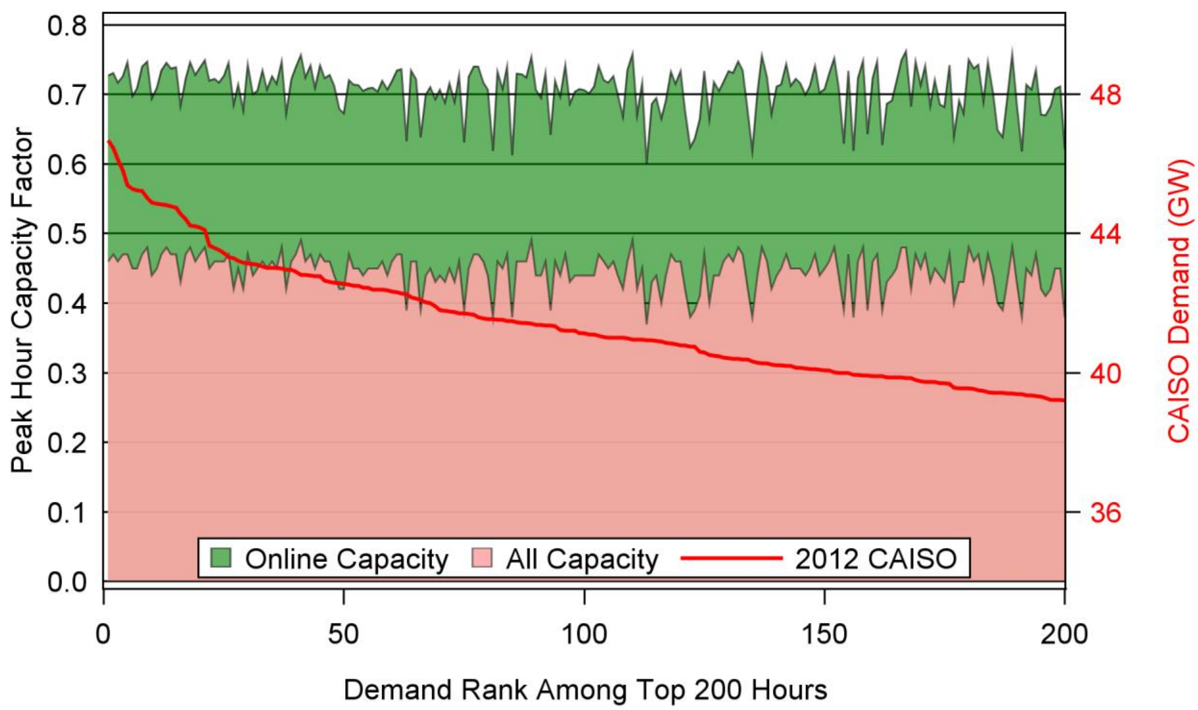
In 2012, these top 200 demands occurred during 38 of the 85 days between July 10 and October 2. The peak demand during these top 200 hours ranged from 39.2 to 46.7 GW. Just over half of the peak demand in the top 200 hours occurred over 13 consecutive days from August 6 to 18 during an intense heat wave. The top 200 peak demand hours included 18 hours during weekends. This is unusual since peak demand for many commercial and industrial customers decrease during weekends.

SGIP projects contributed an average peak demand impact of 123 MW during the 200 top demand hours of 2012. The SGIP impacts ranged from 103 MW to 134 MW. The lowest impacts occurred during the weekends when many SGIP projects reduce output partially if not completely due to reduced site demands. A conservative load planning approach would use the low end of this impact range (103 MW) as the SGIP's potential for peak reduction during the top 200 hours of demand.

The impact range of 103 to 134 MW represents a capacity factor range of 0.37 to 0.49. The red shaded area of Figure 5-6 shows the distribution of hourly capacity factors within this range over the top 200 hours, with CAISO demand shown as a solid red line ordered by rank from the peak to the 200th hour. The red shaded area represents all SGIP project capacity, whether retired or not. To demonstrate how retired capacity reduces peak hour capacity factors, Figure 5-6 shows capacity factors from on-line capacity alone with the green shaded area. The range among on-line capacity is higher, from 0.60 to 0.75.

6 Permanent capacity retirement is considered decommissioned capacity, strictly defined as physically removed from its original site. Some decommissioned capacity may be relocated to new sites. Such relocations are not tracked and any demand impacts they provide are not considered contributions to program impacts.

Figure 5-6: Top 200 CAISO Demand Hour Capacity Factors, On-line versus All SGIP Capacity



Assuming little of recent capacity additions and capacity now in the queue will be retired in the near term, we expect the vast majority of it to be online during peak hours in 2013. We project capacity factors for this newer capacity to be well above the 0.71 average for on-line capacity from Figure 5-6.

Key Takeaways:

1) ***Demand impact during the 2012 CAISO peak reached new high of 128 MW, or 46 percent of the SGIP's total capacity.***
2) ***Peak demand impacts increased largely due to capacity additions in 2011 and 2012.***
3) ***The SGIP's impact over the top 200 hours of CAISO demand during 2012 was no less 103 MW, or about 37% of the SGIP's total capacity.***
4) ***The SGIP's ability to impact peak demand is reduced by ongoing retirement of older capacity, but recommissioning may restore some impact potential.***
5) ***The SGIP's ability to affect peak demand depends largely on SGIP project capacity, its age, and the utility customer's choice of generation schedules. Additional factors include technology choice and operating costs that may be affected by changing fuel costs and air quality regulations.***

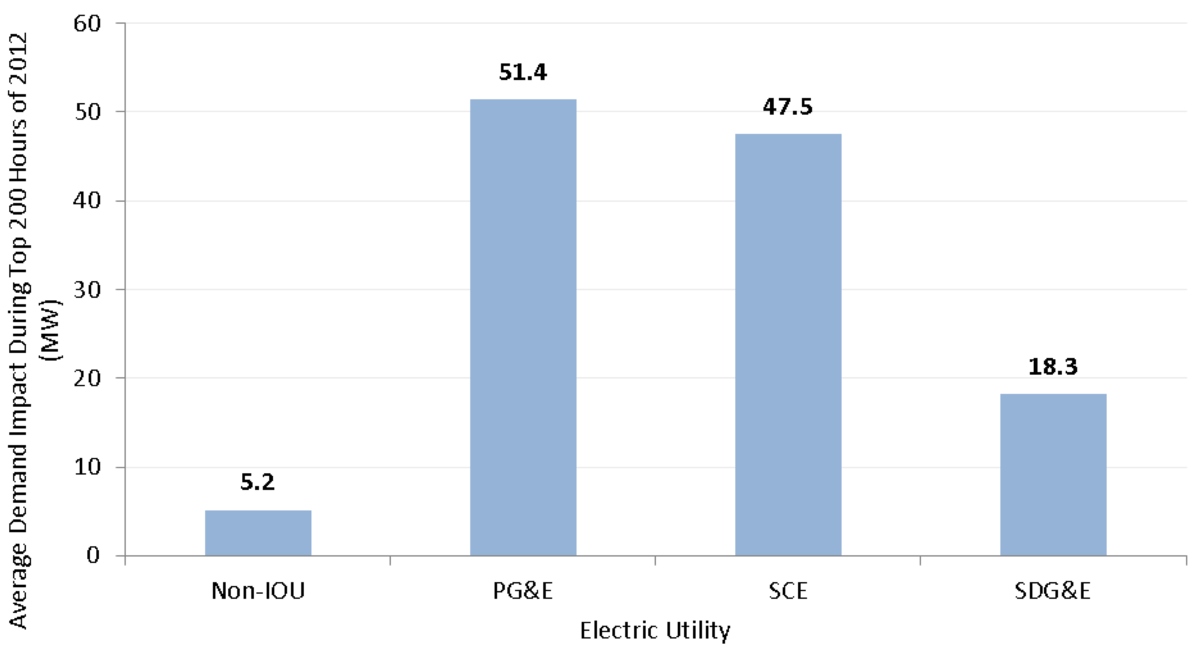
5.2 Investor Owned Utility Impacts

Like the CAISO, the three IOUs (PG&E, SCE, and SDG&E) have specific top demand hours and associated demand impacts. In examining these demand impacts we associate individual SGIP projects with their particular electric utility. Most SGIP projects have one of the three IOUs as their electric utility. About 5% of SGIP projects are not served by an IOU. We do not have information on the top demand hours for any non-IOU utilities. To describe the demand impacts of these 'Non-IOU' SGIP systems as we do for IOU-served systems, we consider their utility's top hours to be the same as those of the IOU associated with their program administrator. For systems with SCG as the program administrator, we consider the top 200 hours to be those of SCE.

Top 200 Demand Hours

We consider each IOU separately although many of their top 200 hours are the same. Figure 5-7 shows average demand impacts during the top 200 hours for the three IOUs from the SGIP systems they serve. It also shows the average demand impacts from SGIP systems not known to be served by an IOU.

Figure 5-7: Top 200 Hours Average Demand Impacts by Electric Utility



As with different technology and fuel types during CAISO demand hours, SGIP demand impacts differ between IOUs largely due to their contributing system capacities. Table 5-1 lists system counts and capacities for the different electric utilities at the end of 2012.[7]

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[7] Capacity totals and system counts at year's end may exceed those during the year's peak demand hours because new capacity may be added after peak demand hours occurred.

Table 5-1: SGIP Capacities by Electric Utility

Electric Utility	*Project Count*	*Rebated Capacity (MW)*	*Capacity as Percentage of Total*
PG&E	260	111	39%
SCE	214	120	43%
SDG&E	60	34	12%
Non-IOU	67	18	6%
TOTAL	**601**	**282**	**100%**

5.3 Peak Demand Impact Economic Value

SGIP peak demand impacts are less than one percent of CAISO total demand but the relief they provide to the grid has substantial economic value. To estimate a benchmark of that value we consider the avoided costs of demand impacts during the IOUs' top 200 hours of 2012. This benchmark is a simple yardstick to approximate the value of demand impacts.

Hourly Avoided Cost Model

To estimate avoided costs per MWh of demand impact we use an avoided cost model produced for the CPUC by the firm *Energy and Environmental Economics* (E3).[8] The avoided cost model has been approved for use with demand response valuation protocols. The model provides building climate zone-specific hourly avoided costs for each IOU. To every MW of demand impact from an SGIP system in a particular hour we assign its IOU's and climate zone's corresponding 2012 hourly avoided cost for supply of one MWh from the grid. The sum of these avoided costs across the IOU's top 200 hours is then the estimated value to the IOU of the 2012 demand impacts.

8 Additional information about E3's avoided cost model can be found at http://www.ethree.com/public_projects/cpuc5.php

Table 5-2: E3 Avoided Cost Model Components

Cost Component		***Valued for Achieved Demand Impact***
1	Generation energy	✓
2	Losses	✓
3	Ancillary services	✓
4	System (generation) capacity	✓
5	T&D capacity	✓
6	Environmental costs	✓
7	Avoided renewable purchases	✓

Top 200 Demand Hour Impacts Value

Table 5-3 lists the sums of avoided costs over the IOUs' top 200 hours. It includes avoided costs from achieved demand impacts. These sums are benchmark estimates of the value of SGIP achieved during the top 200 demand hours for each IOU.

Table 5-3: Avoided Costs of SGIP Demand Impacts by Electric Utility[9]

Electric Utility	***Achieved Demand Impact Avoided Cost (000 $)***
PG&E	$2,510
SCE	$3,222
SDG&E	$936
Non-IOU	$346
TOTAL	**$7,013**

SCE has the greatest achieved avoided costs. High costs associated with T&D congestion in SCE territory explain these higher avoided costs. The total avoided cost of $7 million is the value that SGIP demand impacts provided over the IOUs' top 200 hours in 2012. SGIP demand impacts in other hours provide some additional value but at far lower rates.

Table 5-4 lists the sums of avoided costs derived by IOU but summarized by program administrator. Differences between Table 5-3 and Table 5-4 arise from values being assigned to SCG as program administrator that had been assigned to an IOU. SCG systems account for a majority of demand impact value reported for SCE in Table 5-3.

[9] The SGIP provides benefits in four areas; this represents the value only associated with peak demand reduction.

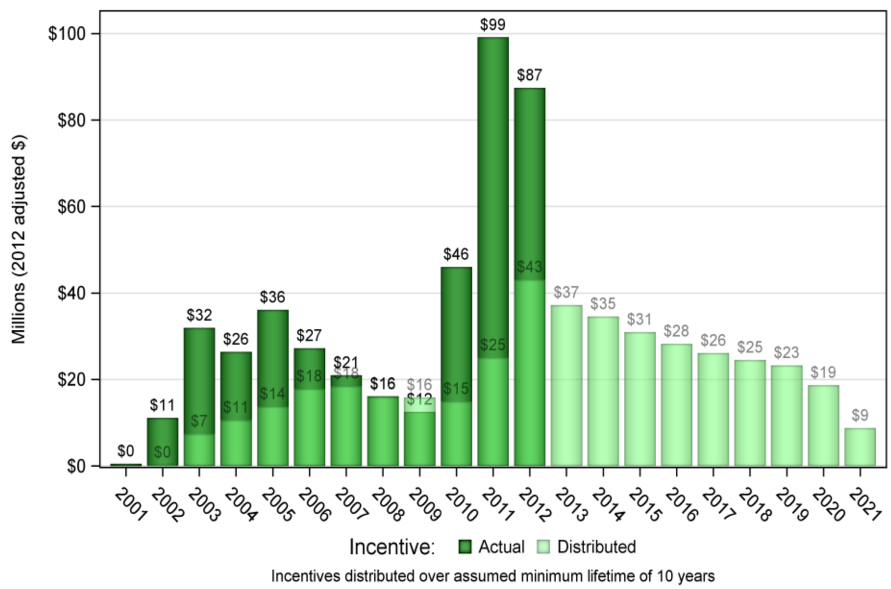
Table 5-4: Avoided Costs of SGIP Demand Impacts by Program Administrator[10]

Program Administrator	*Achieved Demand Impact Avoided Cost (000 $)*
CCSE	$915
PG&E	$2,443
SCE	$1,181
SCG	$2,475
TOTAL	**$7,013**

SGIP Incentive Comparison

We now compare the 2012 benchmark demand impact values with actual incentives paid under SGIP. We do not compare 2012 demand impact values with SGIP incentive totals to date. SGIP incentives may be said to support both past and future demand impacts in addition to those of 2012. To recognize past and future impacts we distribute some SGIP incentives toward the future and some toward the past demand impacts. Figure 5-8 shows incentives both actual and distributed.

Figure 5-8: Distribution of Incentives over Time



To distribute incentives we assume that SGIP systems currently less than 10 years old will provide impacts for only 10 years. We distribute their incentives over 10 years but defer some of their incentives into the future. We assume older systems will provide their last impacts in 2012, and distribute their incentives across their lifetimes based on their on-peak[11] demand impacts, including

[10] The SGIP provides benefits in four areas; this represents the value only associated with peak demand reduction.

[11] Based on IOU-specific definitions of on-peak period hours used for commercial time-of-use tariffs. For PGE, this is noon to 6 p.m., May through October, approximately 749 hours per year. For SCE: this is noon to 6 p.m., June through September, approximately 498 hours per year. For SDGE, this is 11 a.m. to 6 p.m., May through September, and 5 p.m. to 8 p.m., October through April, approximately 1164 hours per year.

2012. We do not defer any of their incentives into the future. For example, a system that first operated in 2004 has 90% of its incentive distributed across its on-peak demand impacts through 2012, and the remaining 10% deferred to 2013. For a system that first operated in 2012 its incentive would be deferred as late as 2021.

Distributing incentives across the IOU's on-peak hours only results in SCE-served systems having incentives distributed across fewer than 500 hours per year. For SDG&E-served systems the distribution includes more than twice that number. This difference in on-peak hour counts effectively increases the incentive associated with demand impacts for SCE served systems.

Of the $43 million of distributed incentives shown in Figure 5-8, $10 million are associated with systems served by municipal or other electric utilities.[12] So we compare just $33 million of distributed SGIP incentives in 2012 to avoided cost values. Figure 5-9 shows 2012 distributed SGIP incentives and avoided cost totals.

Figure 5-9: Demand Impact Avoided Cost Value versus SGIP Distributed Incentive Costs

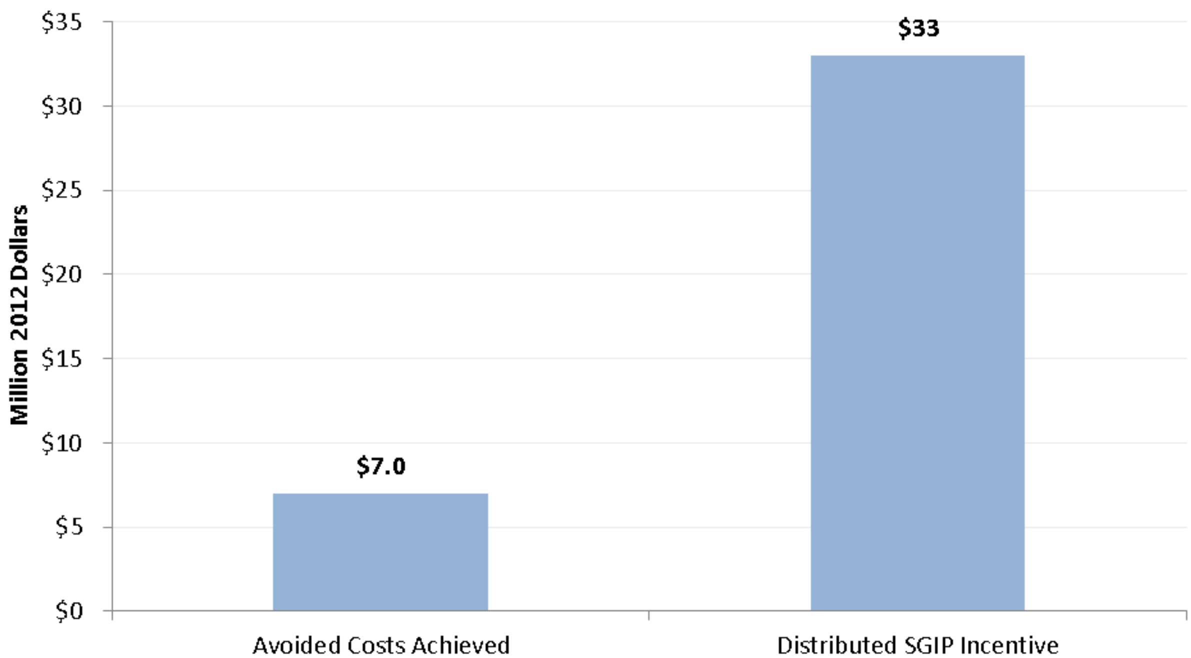


Figure 5-9 indicates that the SGIP, although not designed strictly as a demand impact program, provides demand response benefits valued at $7 million in terms of avoided costs.

Because the SGIP is not designed to deliver demand impacts alone, this result is not surprising. In conducting the valuation of the peak demand impacts, we recognize that the SGIP has four primary purposes. In addition to the economic values placed on peak demand reductions, there is value to the GHG reductions achieved by the SGIP. There are also less quantitative but still significant market transformation and transmission and distribution benefits resulting from the SGIP. As discussed in

[12] Systems that are not served by an IOU electric utility are served by an IOU gas utility.

Chapter 7, in the future, the SGIP is projected to achieve higher benefit-to-incentive values as SGIP incentive declines and as the market realizes improvements to the efficiency with which participating technologies are produced.

Figure 5-8 shows the 2012 incentive distribution to be the largest distribution. This is due in part to the assumption of a 10-year lifetime and in part to the actual incentives paid in 2010 through 2012. An assumption of 15 years would reduce the 2012 incentive distribution and the $33 million of Figure 5-8. While it is clear many systems have not continued to provide impacts, other systems still may continue to prove useful for two decades and more.

Distributed incentives per unit of impact are expected to decline in 2013 and beyond. The decline in incentive distributions as seen in Figure 5-8 is just one reason. We also expect that new systems entering under current SGIP guidelines will deliver more on-peak impacts over more years than earlier systems. Fuel cells and gas turbines in the queue are expected to deliver high on-peak capacity factors beyond 2020. As a result, we fully expect SGIP to deliver greater demand response benefits in future years compared to those observed in 2012.

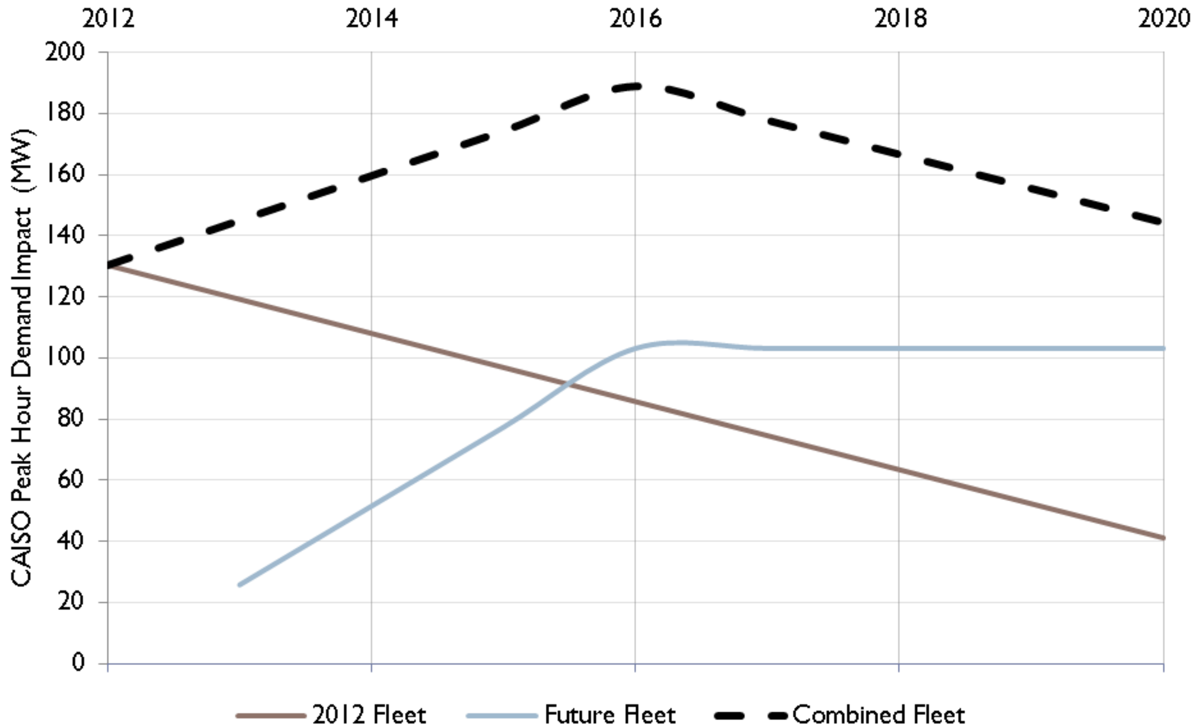
5.4 Future Demand Impacts

Similar to the approach in the previous section on energy impacts, here we project future demand impacts from SGIP capacity. This provides an outlook of the program's ability to deliver demand impacts in the future. We project demand impacts from a combination of SGIP's 282 MW of existing capacity,[13] technology portfolio, and the 141 MW capacity portfolio in the current queue of reserved systems. We assume 35 MW of capacity, one quarter of the current queue, comes online at the start of each year from 2013 through 2016. Lastly, we assume that the SGIP is not extended and no new applications come in after December 31, 2015.

Figure 5-10 shows projected demand impacts of both the existing SGIP capacity 'fleet' and of the assumed future capacity fleet. It also shows total program demand impact as a dashed black line.

[13] This excludes all existing wind and photovoltaic capacity.

Figure 5-10: 2012 and Projected CAISO Peak Hour Demand Impacts through 2020



Capacity additions from the queue increase the demand impact of the future fleet through 2016. As with energy impacts, we assume no decline in impact from this new future fleet capacity through 2020 but assume historic declines for the 2012 fleet.

Total program demand impact increases through 2016 to a maximum of 189 MW. After 2016, demand impact declines as capacity additions stop and capacity from the 2012 fleet either retires or simply generates at lower levels. Capacity grows by 51% from 2012 to 2016 while demand impact increases by 48% from the 2012 demand impact. The decline in impact from the 2012 fleet is offset in part by high capacity factors assumed for much of the new fleet capacity.

2012 Greenhouse Gas Impacts

6

6 2012 GREENHOUSE GAS 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 program were designed to maximize electricity generation during utility system peak periods and not necessarily to reduce greenhouse gas (GHG) emissions. Consequently, any GHG emission reductions achieved by SGIP systems under the original program rules were positive externalities of the program.

In 2006, the California Legislature passed Assembly Bill (AB) 32(Nunez), the Global Warming Solutions Act. Senate Bill 412 (Kehoe), passed in 2009 required the CPUC to establish GHG goals for the SGIP. In response, California Public Utilities Commission (CPUC) Decision (D.) 11-09-015 modified the SGIP to include distributed generation (DG) and advanced energy storage (AES) technologies that would result in the reduction of GHG emissions. As of December 31, 2012, only 400 kW of project capacity subject to the program's new rules had been rebated. In other words, the vast majority of systems included in this analysis were deployed prior to the 2011 requirements. These "pre-SB 412" systems represent a legacy fleet not required to achieve GHG reductions.

This section discusses the GHG emissions impacts of the SGIP during 2012 with a forward looking perspective. The scope of this analysis is limited to carbon dioxide (CO_2) and methane (CH_4) emissions impacts associated with SGIP projects. The discussion is organized into the following sub-sections:

- *Analysis Approach & 2012 Impacts*
- *Performance of 2012 Non-Renewable Systems*
- *Performance of 2012 Renewable Biogas Systems*
- *Potential Impacts of Emerging Technologies*
- *Valuing GHG Emissions and Future Outlook*

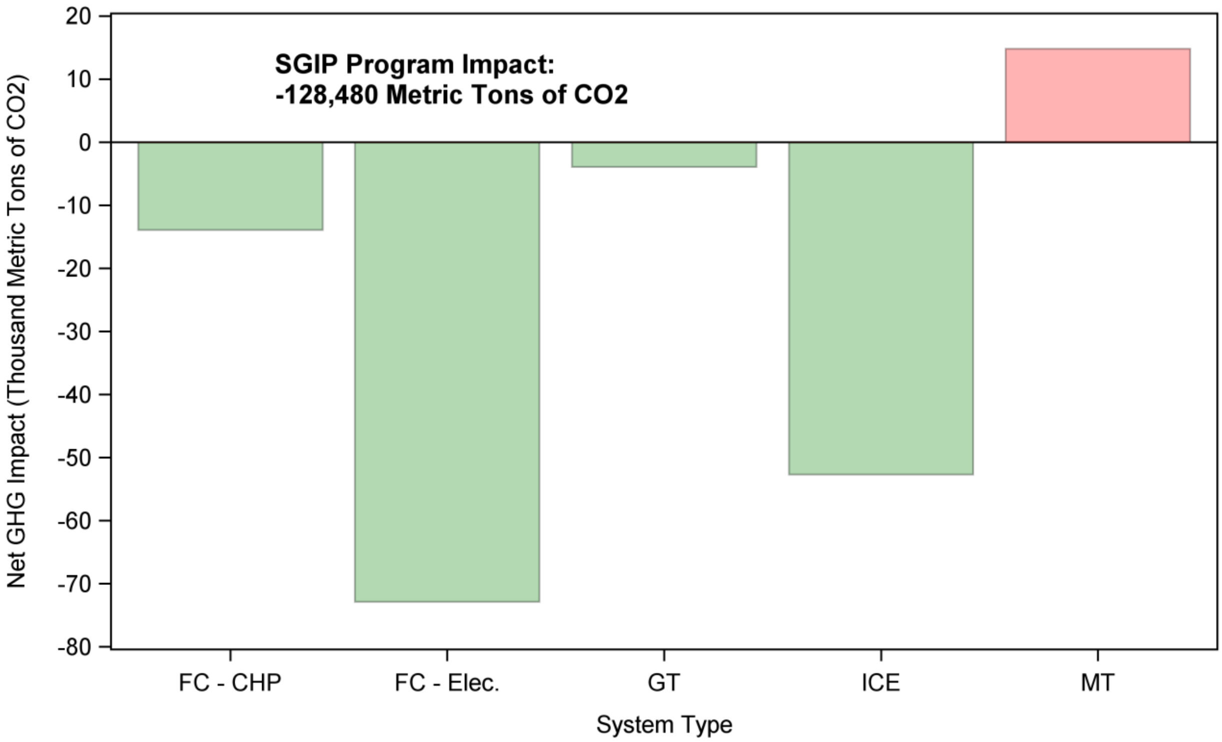
6.1 Analysis Approach & 2012 Impacts

GHG emission impacts are determined by comparing the emissions generated by SGIP systems to those 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 waste heat avoid emissions associated with displacing boiler use.

In 2012, the net GHG impact of the SGIP was a reduction of more than 128 thousand metric tons of CO_2. Put differently, systems rebated by the SGIP generated less emissions than those that would have occurred in the absence of the program.

Figure 6-1 shows the net GHG impacts of five major technologies rebated by the SGIP. Electric fuel cells and internal combustion (IC) engines achieved the greatest GHG emission reductions. Fuel cells with heat recovery and gas turbines achieved marginal reductions, while microturbines were the only technology that increased net GHG emissions.

Figure 6-1: GHG Impact by Technology (2012)[1]



FC – CHP = CHP fuel cell, FC – Elec. = All electric fuel cell, GT = Gas turbine, ICE = Internal combustion engine, MT = Microturbine

The net GHG impacts attributed to each SGIP Program Administrator (PA) are summarized in Table 6-1.

Table 6-1: GHG Impact by Program Administrator (2012)

Program Administrator	*Net GHG Impact (Tons of CO_2)*	*Percent of GHG Impact*
CCSE	-15,818	12%
PG&E	-69,008	54%
SCE	-25,115	20%
SCG	-18,539	14%
Total	**-128,480**	**100%**

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

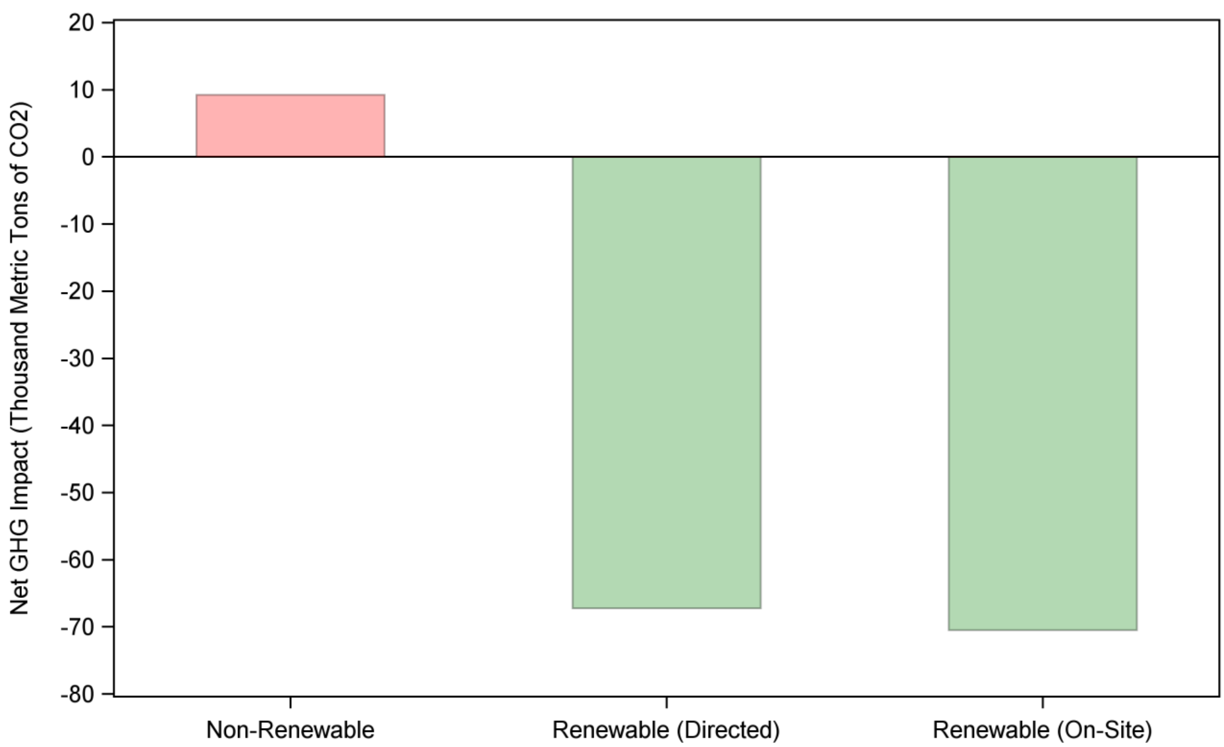
GHG impacts associated with each fuel type are shown in Figure 6-2. Renewable fueled projects are further classified into those that consume biogas at the source (On-Site) and those that procure biogas

[1] There was insufficient data to estimate the 2012 impacts of wind and advanced energy storage projects. The potential impacts of these technologies are addressed in Section 6.4.

from a distant source (Directed). In CPUC Decision 09-09-048 (September 24, 2009), eligibility for renewable fuel use incentives was expanded to include “directed biogas” projects. Deemed to be renewable fuel use projects, directed biogas projects are eligible for higher incentives under the SGIP.

Directed biogas projects consume biogas fuel that is produced at another location. The procured biogas is processed, cleaned, and injected into a natural gas pipeline for distribution. Although the procured 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. Eligibility of directed biogas projects in the SGIP is now limited to gas procured in California. [2]

Figure 6-2: Net GHG Impact by Fuel Type (2012)



The GHG impact of non-renewable projects was positive in 2012. In other words, non-renewable systems increased GHG emissions relative to the emissions that would have occurred in the absence of the program. Renewable projects provide the SGIP’s main source of net GHG emission reductions.

The following sections provide more information about the GHG performance of SGIP technologies in 2012.

6.2 2012 Non-Renewable GHG Performance

Non-renewable SGIP systems include fuel cells, gas turbines, internal combustion engines, and microturbines. These systems consume natural gas and generate electricity to serve a customer’s load. Non-renewable SGIP systems produce GHG emissions that are proportional to the amount of fuel they

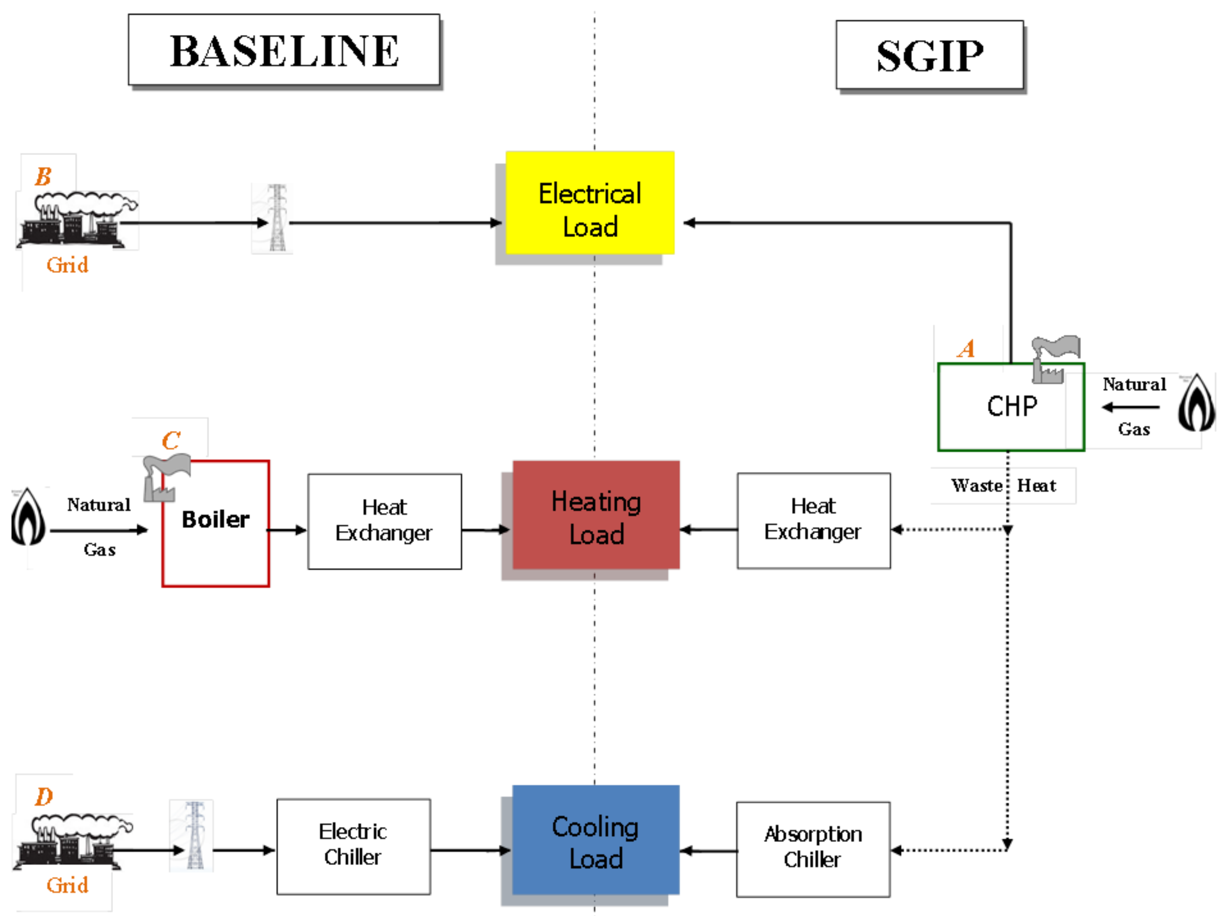
[2] The November 7, 2011 version of the SGIP Handbook limits directed biogas eligibility to in-state sources only.

consume. In the absence of the program, the customer's electrical load is assumed to have been served by the electricity distribution company. Consequently, if SGIP systems only served electrical loads, they would need to generate electricity more efficiently than the avoided marginal grid generator in order to achieve GHG emission reductions.

Certain SGIP systems 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 have been met by a natural gas boiler, and a cooling end use is assumed to have been 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 generated the electricity to run the chiller.

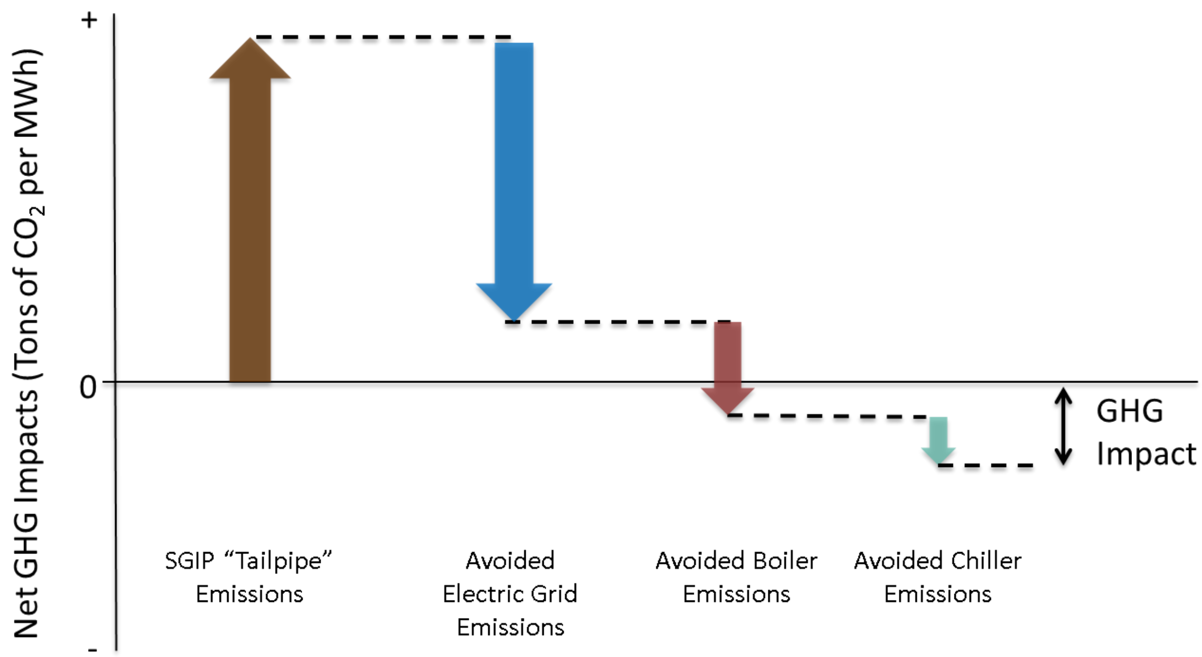
The relationship between the emissions generated and avoided by the SGIP is summarized in Figure 6-3. A complete overview of the GHG impact methodology is provided as Appendix C.

Figure 6-3: Summary of SGIP vs. Avoided Emissions



GHG impacts are the difference between SGIP emissions and avoided emissions. Figure 6-4 demonstrates how GHG reductions may be achieved if the emissions generated by the SGIP system are less than the sum of the electric grid, boiler, and chiller emissions avoided by the SGIP.

Figure 6-4: GHG Impact Calculation

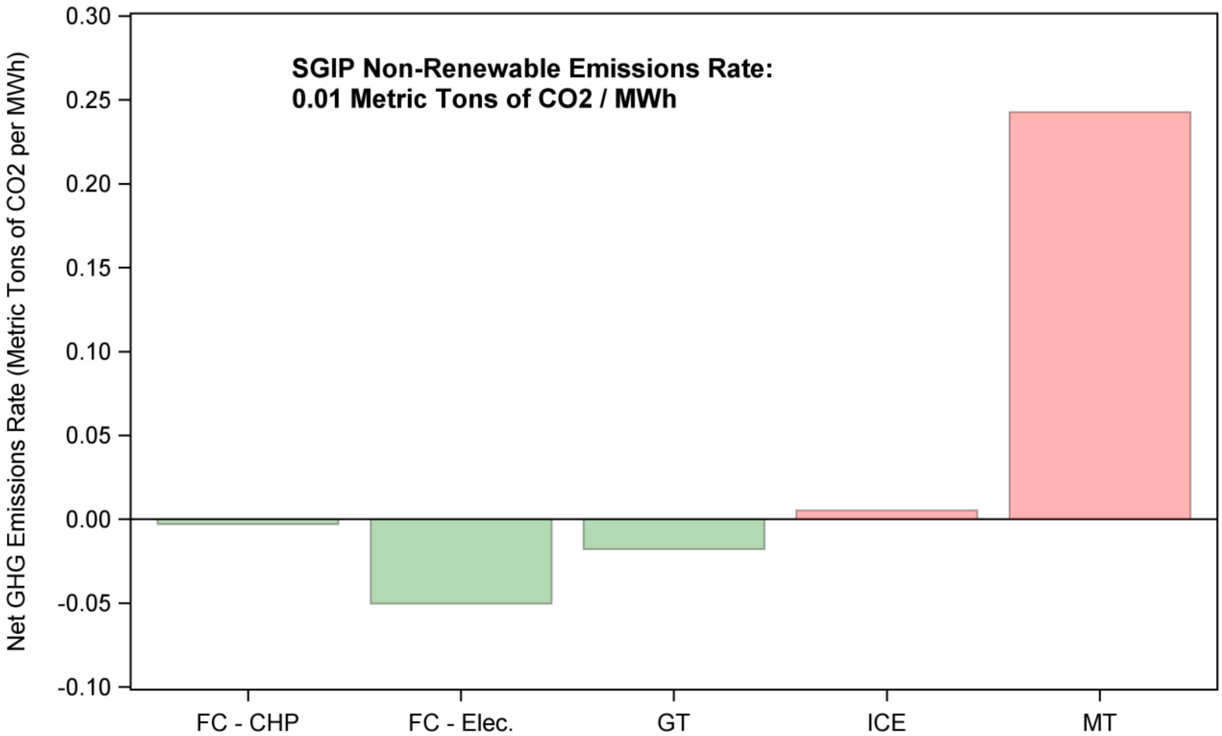


The GHG performance of non-renewable SGIP systems is summarized in Figure 6-5. Two important distinctions must be drawn between Figure 6-5 and Figure 6-1.

1. Figure 6-5 shows CO_2 emissions rates in tons per MWh while Figure 6-1 shows total tons of CO_2 in 2012, and
2. Figure 6-5 describes the performance of non-renewable systems while Figure 6-1 presents the impacts of all projects including renewable systems.

Figure 6-5 also shows the emissions rates generated and avoided by each technology. The SGIP emissions rate minus the sum of the emission avoided from grid, boiler, and chiller usage result in the net GHG emission rate.

Figure 6-5: 2012 Non-Renewable GHG Emissions Impacts by Prime Mover (Tons CO2/MWh)



Net	**-0.01**	**-0.05**	**-0.02**	**0.01**	**0.24**
SGIP	+0.50	+0.40	+0.57	+0.62	+0.83
Grid	-0.45	-0.45	-0.45	-0.46	-0.45
Boiler	-0.06	0.00	-0.11	-0.14	-0.13
Chiller	0.00	0.00	-0.02	-0.01	-0.01

Fuel cells and gas turbines were the only non-renewable SGIP technologies that reduced GHG emissions. All-electric fuel cells achieve reductions exclusively by generating electricity more efficiently and cleaner than the avoided system on the grid. Gas turbines and fuel cells that recover waste heat to serve an on-site thermal load generate electricity less efficiently than the grid, but they avoid emissions from the use of boilers and chillers. This additional component of avoided emissions allows combined heat and power (CHP) fuel cells and gas turbines to achieve negative net GHG emissions rates.

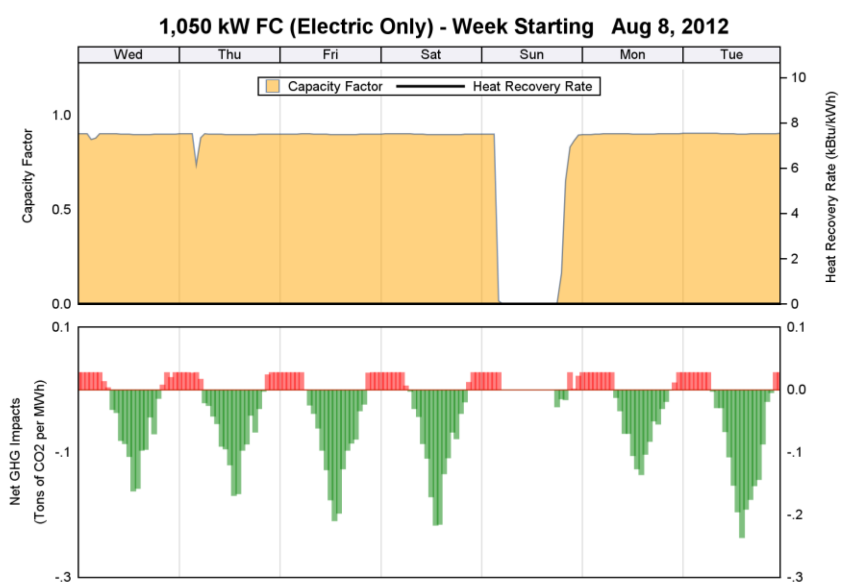
Non-renewable internal combustion engines and microturbines generated more emissions than they avoided in 2012. For both technologies, not enough waste heat was recovered to offset the increased emissions due to electricity generation being less efficient than electricity generated from the grid. Non-renewable microturbines have high GHG emissions rates due to their low electrical efficiencies. Since microturbines were observed to be significantly less efficient than the avoided grid generator, high heat recovery is required to generate sufficient boiler and chiller avoided emissions. Microturbine heat recovery rates were not sufficiently high in 2012 to achieve GHG reductions.

As the SGIP moves forward, several factors will affect emissions from non-renewable projects. Some of these factors and their implications for SGIP GHG impacts in the future are discussed in the following case studies.

Electric Only Fuel Cells – The Case of Zero Useful Waste Heat Recovery

Electric only fuel cells are able to achieve higher electrical conversion efficiencies than other DG technologies partly due to the internal utilization of waste heat. As a result, these types of systems do not have any useful waste heat available to be used for meeting a site's thermal loads. The GHG emission rate for a representative electric only fuel cell is shown in Figure 6-6. The shaded area in the top half of the figure plotted on the left axis is the system's hourly capacity factor. This system operates at a steady capacity factor close to 1.0 or in other words a "baseload" operating mode.

Figure 6-6: GHG Profile for an Electric Only Fuel Cell



The hourly emission rate, the rate at which this system increases (red bars) or decreases (green bars) GHG emissions is shown in the bottom half of Figure 6-6. In this example the system is assumed to have a constant electrical efficiency and the capacity factor remains relatively constant throughout the week. Why then do the hourly net GHG impacts exhibit so much intra-day variability? The reason is that the mix of generators supplying electricity to the grid does not remain constant. This variability means that the source of the electricity and therefore the associated emission rate that is "avoided" by the SGIP system changes from hour to hour.

In Figure 6-6, the avoided emission rate close to midnight corresponds to the clusters of red bars (net GHG emission increase), and is less than the emissions rate of the electric only fuel cell. In other words, during the hours around midnight, this electric only fuel cell is avoiding electricity that would have been generated more efficiently and therefore with fewer emissions from the grid. On the other hand, the electric only fuel cell in this example is avoiding more emissions than it generates during the day as shown by the clusters of green bars during daytime hours.

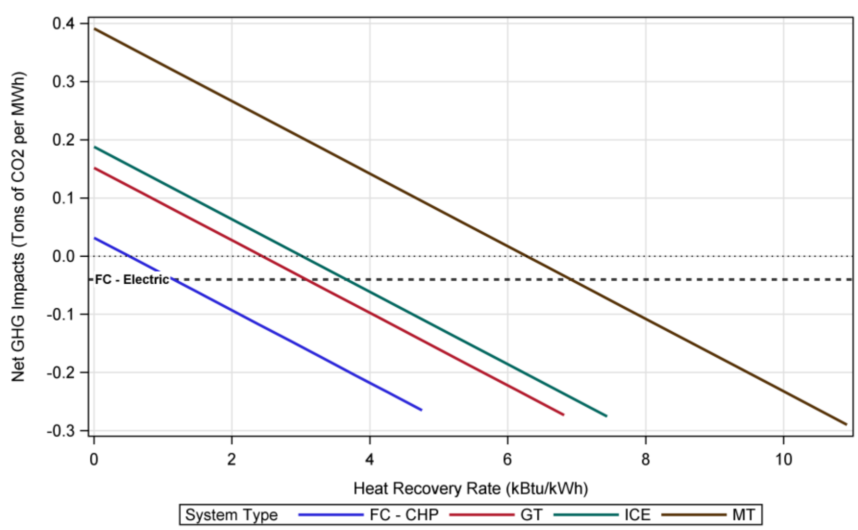
By examining the lower half of Figure 6-6 one can determine that, because the area under the green bars is greater than the area under the red bars, this system reduced GHG emissions during the week of August 8, 2012. All non-renewable electric only fuel cells rebated by the SGIP reduced GHG emissions by a total 4,650 metric tons of CO_2 during 2012.

Figure 6-6 also illustrates the effect that an increasingly efficient grid[3] would have on GHG impacts of the SGIP. If the emissions rate of the grid decreases, SGIP technologies (especially those without the ability to serve onsite thermal loads) will find it more difficult to achieve net negative GHG impacts. It is expected that the GHG emissions rate of the grid (and therefore the SGIP's avoided emissions) will decrease due to state policies and technological advances.

CHP Technologies – The Need for Useful Waste Heat Recovery

Not all technologies can achieve electrical efficiencies that are as high as electric only fuel cells. While efficiencies as high as $55\%_{LHV}$ were observed for electric only fuel cells, a typical combustion generator will achieve an electrical efficiency somewhere between $20\text{-}35\%_{LHV}$[4]. The impact of SGIP electrical efficiencies on GHG emissions is that systems with lower electrical efficiencies have a more difficult time producing energy in a manner that is more efficient and therefore cleaner than the grid. In other words, low efficiency SGIP systems potentially avoid "cleaner" electricity leading to increased GHG emissions relative to the grid. To get around this, systems with lower electrical efficiencies must also capture waste heat to be used on-site. As described in Section 6.2, the recovery of useful waste heat carries the added benefit of reducing or avoiding the use of natural gas boilers to supply a thermal load. This issue is described in more detail in Figure 6-7. Five lines are drawn each representing a different technology found in the SGIP. The useful waste heat recovery rate is plotted on the horizontal axis and the GHG impact associated with that heat recovery rate is shown on the vertical axis. Three things become apparent from reviewing Figure 6-7:

Figure 6-7: Heat Recovery Requirements for GHG Reductions



- *Over the course of a typical year, CHP technologies that do not recover any heat will inevitably increase GHG emissions*
- *To reduce GHG emissions, technologies with lower electrical efficiencies, such as microturbines must achieve greater heat recovery rates than technologies with higher electrical efficiencies such as CHP fuel cells*
- *All electric fuel cells provide reliable GHG reductions, but CHP systems have the potential to achieve greater reductions with sufficiently high heat recovery rates*

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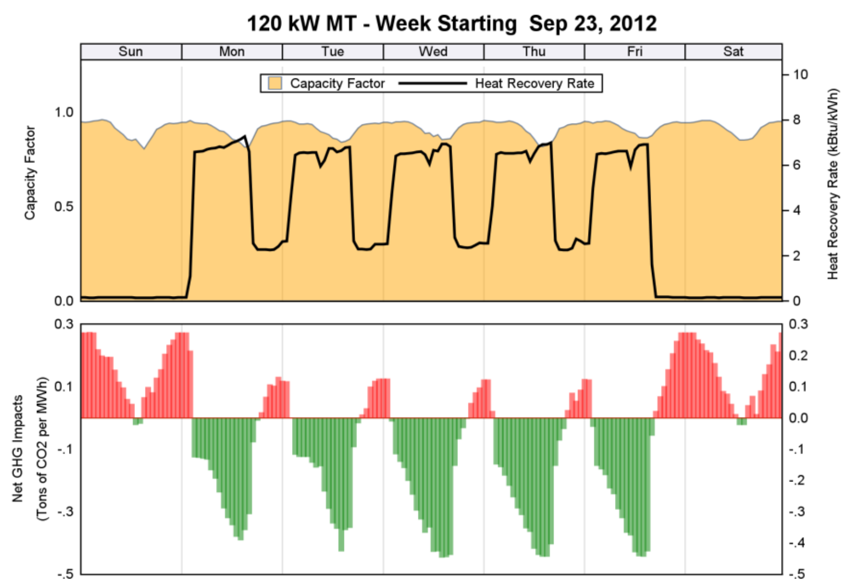
[3] In the context of GHG impacts, the grid comprises a mix of dispatchable simple cycle gas turbines and combined cycle gas turbines operating at the margin.

[4] Lower heating value (LHV) assumes 920 Btu of chemical energy per cubic foot of natural gas.

Figure 6-8 shows the GHG emissions from a representative CHP system (in this case a microturbine) during a week in 2012. The useful waste heat recovery rate for this system is shown as the solid black line in the top half of the figure plotted against the right vertical axis. The system provides near-baseload electrical generation to the site as seen by the capacity factor oscillating around 90%.

Three distinct heat recovery operating modes can be observed. During the weekend (Sat & Sun) the heat recovery rate is zero, meaning the thermal energy produced by the CHP system is being dumped to the atmosphere. Two other operating modes are observed during the weekdays (Mon – Fri). During the evening hours, the system is recovering some, but not all of the thermal energy – useful heat recovery rates between 2 and 3 MBtu/kWh are observed. During early morning and afternoon hours, a large portion of the useful waste heat is recovered and heat recovery rates between 6 and 7 MBtu/kWh are achieved.

Figure 6-8: GHG Profile for Various Heat Recovery Modes



The fact that the same system exhibits three distinct thermal energy recovery modes provides an excellent opportunity to discuss the implications each mode has for GHG emission impacts. The worst operating mode from a GHG emission standpoint is heat dumping (zero useful heat recovery rate) as seen during the weekend hours for the system in Figure 6-8. The large areas of red bars indicate that this is a period of substantial increase in GHG emissions.

The next best operating mode entails recovery of some but not all available heat. In Figure 6-8, the system operates at about a third of its maximum observed heat recovery rate on weekday evenings. In this operating mode, the magnitude of the net GHG emissions is reduced, but they remain positive in value. This can be observed in the small clusters of red bars in the lower half of the figure during weekday evenings.

The five large clusters of green bars in the bottom half of Figure 6-8 are the only periods when the system reduced GHG emissions. These periods coincide with instances during which the system recovered the greatest amount of waste heat. During these hours, the avoided emissions from electricity consumption and boiler operation are greater than the emissions generated by the SGIP system. In other words, high heat recovery rates were necessary for this system to achieve GHG emissions reductions.

The three thermal operating modes depicted in Figure 6-8 and their GHG implications are summarized below:

- *Heat dumping during weekends – this operating mode leads to the greatest positive GHG impact.*

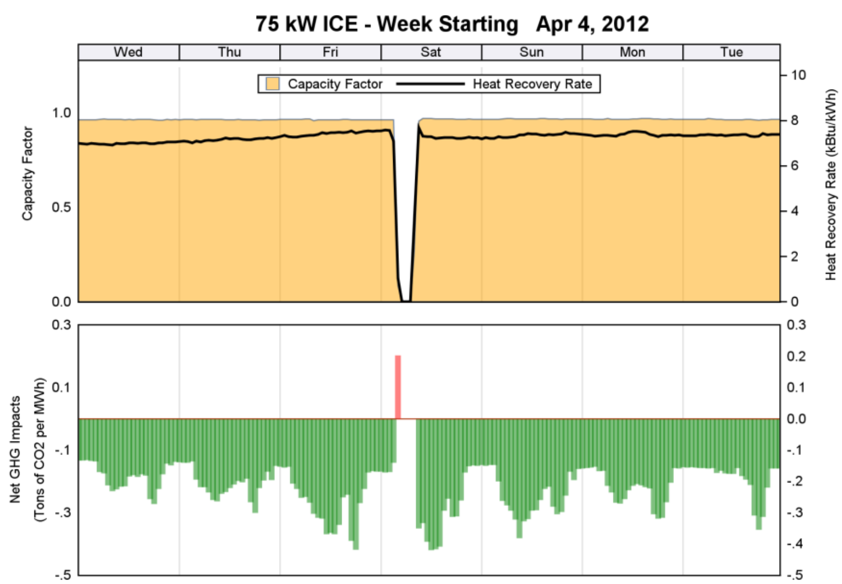
- *Partial useful heat recovery during weekday evenings – this operating mode reduces the GHG impact but it remains positive.*
- *Maximum useful heat recovery during weekday mornings – this is the only operating mode that achieves GHG emission reductions for the system in Figure 6-8.*

The purpose of this case study was to highlight the important relationship between useful waste heat recovery rate and net GHG impact. The November 7, 2011, version of the SGIP handbook[5] introduced a GHG performance based incentive. This case study demonstrates that if electricity is being generated less efficiently than the grid, a high heat recovery rate is required to reduce GHG impacts.

The 2011 SGIP handbook also introduced minimum capacity factors below which incentive payments will be reduced. The following case study will demonstrate the implications of capacity factor on GHG emissions.

Thermal Load Following to Maximize Heat Recovery Rate – The Implications of Capacity Factor

Figure 6-9: GHG Profile for Thermal Baseload CHP System



The previous example demonstrated that for most combustion based CHP technologies, high useful waste heat recovery rates are necessary to achieve GHG emission reductions. To that end, the ideal candidate for a CHP system is a site with a continuous large thermal load, such as an industrial process with a continuous demand for thermal energy. Facilities with these types of thermal loads exist. Figure 6-9 is an example of a system that operates at a continuously high useful heat recovery rate. As can be seen by the large area of green bars in the lower half of the figure, the system is continuously operating in a mode that reduces GHG emissions. This is the type of behavior that one would expect from a project that seeks to maximize its incentive payment based on the structure implemented in the 2011 SGIP handbook. Utilities and in particular, gas utilities are in a unique position to know which customer sites have high thermal loads and help solicit these types of projects to the SGIP in the future.

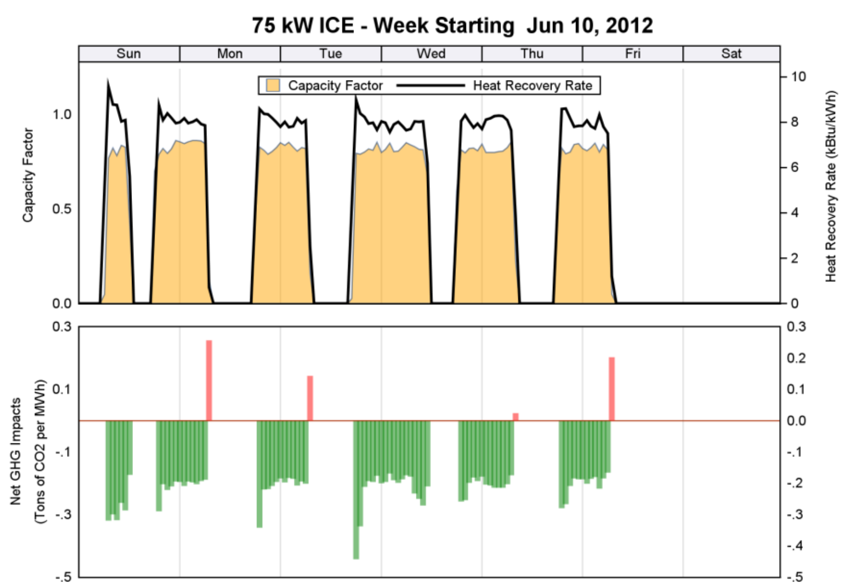
[5] http://www.pge.com/includes/docs/pdfs/shared/newgenerator/selfgeneration/SGIP_Handbook_2011.pdf

Not all facilities have the type of thermal demand shown in Figure 6-9. For example, a small health club might have a high water heating load during the day, but may not have a significant thermal demand overnight. In this example, should the CHP unit continue to generate electricity overnight while dumping the thermal energy to the atmosphere? Dumping waste heat to the atmosphere reduces the system's useful waste heat recovery rate and increases net GHG emissions. Figure 6-10 shows an alternative scenario where the unit appears to only operate when thermal and electrical demand exists.

The behavior in Figure 6-10 is representative of a site that may only have a thermal demand in the evening. From the lower half of Figure 6-10 it can be seen that GHG emissions reductions are achieved during almost all hours of operation in this thermal load following mode. If this CHP system were to generate electricity 24/7 and dump waste heat during periods of low thermal demand, GHG emissions reductions would not be achieved (as seen in Figure 6-8). However, in situations such as this where the electrical load and thermal loads are not coincident other means could potentially be used to achieve GHG reductions. For example, the site could capture and store the waste heat as hot water. The stored hot water could then be used to meet the thermal loads, offsetting boiler fuel and the associated GHG emissions.

During 2012, non-renewable SGIP systems collectively had a net GHG emissions rate of 0.01 tons of CO_2 per MWh resulting in a net increase of 9,227 metric tons of CO_2. Certain non-renewable technologies, such as fuel cells and gas turbines, achieved GHG emission reductions while others, such as internal combustion engines and microturbines, did not. All non-renewable projects have the potential to reduce GHG emissions, but their ability to do so is highly sensitive to the manner in which they operate.

Figure 6-10: GHG Profile for Thermal Load Following CHP System



The examples shown in this section highlight the important relationship between capacity factor, efficiency, and useful waste heat recovery rate on GHG impacts.

Key Takeaways:

1) ***High heat recovery rates are critical to achieving GHG emissions reductions.***
2) ***Electric only fuel cells offer a reliable means of achieving modest GHG emissions reductions.***
3) ***Proper sizing of systems is critical to maintaining high heat recovery rates and potentially high capacity factors as well.***
4) ***Low capacity factors may be acceptable if they are traded for high heat recovery rates.***

6.3 2012 Renewable Biogas GHG Performance

Renewable fueled projects in the SGIP include wind projects and projects that use biogas fuel. Sources of biogas include landfills, wastewater treatment plants (WWTP), dairies, and food processing facilities. Analysis of the GHG emission impacts associated with fuel cells, microturbines, and internal combustion engines using renewable biogas is more complex than for non-renewable projects. This complexity is due, in part, to the additional baseline GHG 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 CO_2 emissions the same way that non-renewable projects can, but they also include GHG emission impacts caused by captured CH_4 contained in the biogas.

Landfill gas, consisting primarily of methane, is produced via biological breakdown of waste material. Methane is required to be combusted (flared) before being released to the atmosphere for safety and environmental reasons. Methane has a high GHG potential and is highly flammable.

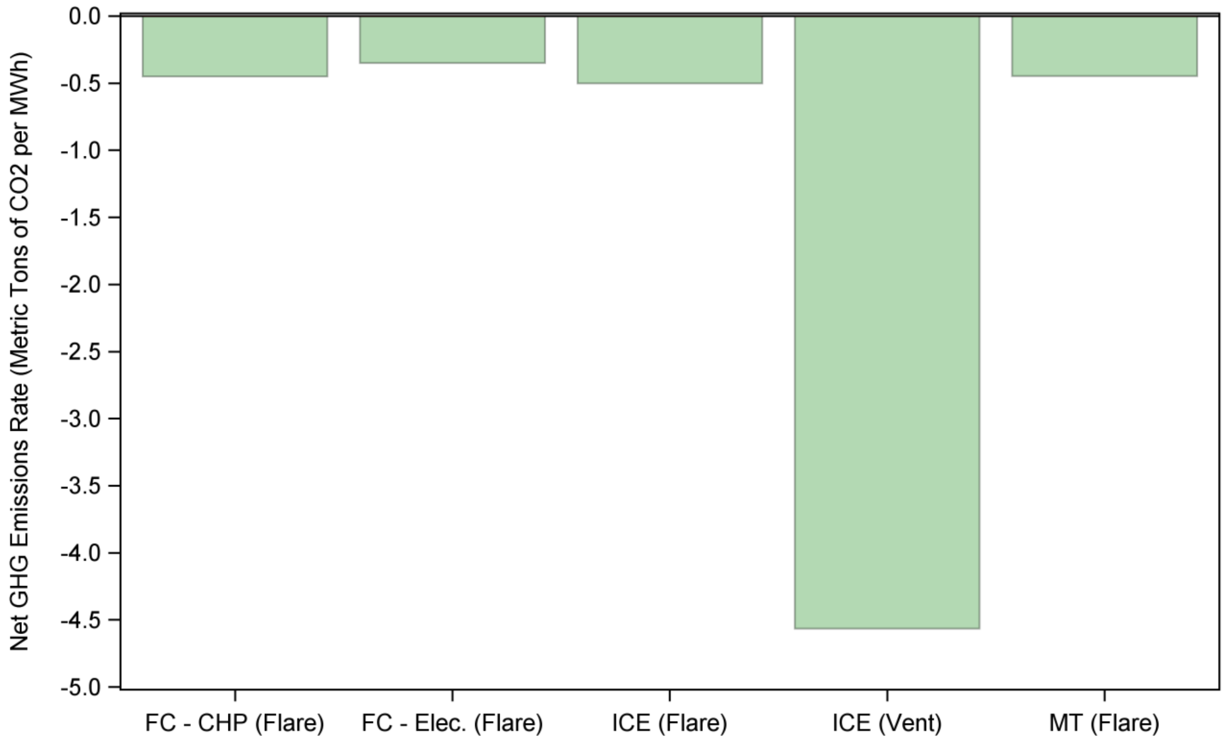
Renewable biogas SGIP projects capture and use CH_4 that otherwise may have been emitted into the atmosphere (vented) or captured and burned (flared). By capturing and utilizing this gas, emissions from venting or flaring the gas are avoided. The concept of avoided biogas emissions is further explained in Appendix C.

Animal waste from dairies and other livestock is often disposed of in man-made lagoons. Within these lagoons the waste undergoes a biological process that converts the waste into methane. This methane is often allowed to vent to the atmosphere.

When reporting emissions impacts from different types of greenhouse gases, total GHG emissions are reported in terms of tons of CO_2 equivalent (CO_2Eq) so that direct comparisons can be made to other components of the baseline. 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 systems is summarized in Figure 6-11. GHG emission impacts rates per MWh are grouped by technology type and biogas baseline. Fuel cells, internal combustion engines, and microturbines were deployed in applications that would otherwise flare biogas. Internal combustion engines were the only technology deployed in applications that would otherwise vent biogas. To date, no gas turbine fueled by renewable biogas has been rebated by the SGIP.

Figure 6-11: Renewable Biogas Net GHG Emissions Rates (2012)



Net	**-0.45**	**-0.35**	**-0.50**	**-4.60**	**-0.45**
SGIP	+0.50	+0.40	+0.62	+0.62	+0.83
Grid	-0.45	-0.45	-0.45	-0.45	-0.45
Boiler	0.00	0.00	-0.05	0.00	0.00
Biogas	-0.50	-0.30	-0.62	-4.74	-0.83

Figure 6-11 highlights the importance of the biogas baseline. All renewable systems have negative (reducing) net GHG emissions rates. Systems with flaring biogas baselines achieved reductions between 0.35 and 0.50 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 4.60 metric tons of CO_2Eq per MWh.

6.4 Potential Impacts of Future Projects

The SGIP was redesigned in 2011 to focus on providing incentives to technologies that reduce GHG emissions. The composition and performance of the portion of the SGIP fleet subject to the new program rules will likely be significantly different than the performance observed to date. For example, non-renewable CHP and fuel cell systems will be required to maintain a capacity factor of 80% or better. Furthermore, CHP technologies must demonstrate that useful heat recovery rates will be high enough to achieve GHG emission reductions.

The composition of the queue of SGIP projects was shown in Section 4. Projects in the queue will not necessarily be completed if they cannot meet certain program requirements, but the distribution of systems is a reasonable indicator of what types of projects are expected to emerge in the SGIP.

Advanced energy storage (AES) projects dominate the queue with 82% of the projects by count. Due to the relatively small size of these systems compared to other technologies, AES projects account for only 27.5 MW (19 percent) of the queue.

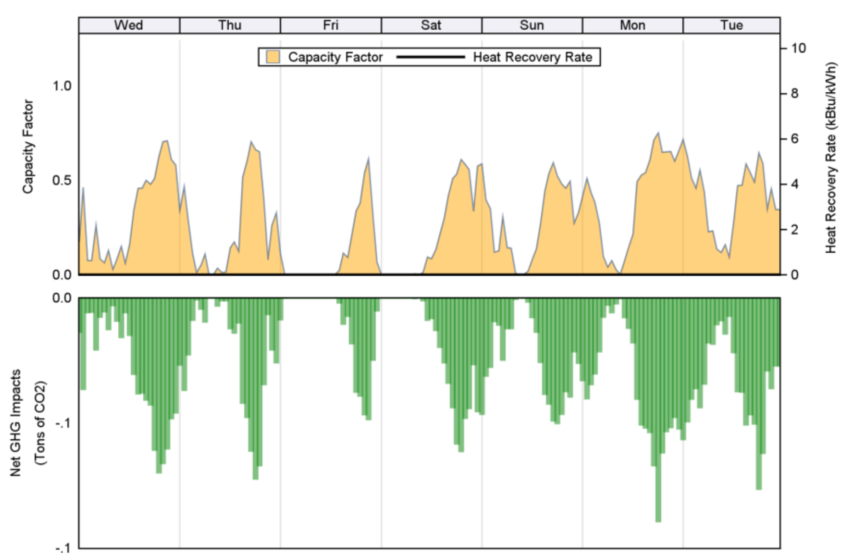
The future composition of the SGIP is expected to include:

- *Electric only fuel cells*
- *Baseload CHP technologies*
- *On-site renewables or in-state directed biogas*
- *Wind projects*
- *Advanced Energy Storage projects*

The impacts of electric only fuel cells, CHP technologies, and renewable systems were discussed in Section 6.2 and Section 6.3. Due to a lack of metered data, the impacts of wind and AES projects were not estimated for 2012. The following section will describe the potential implications of these technologies on GHG emissions.

Wind Systems – Avoided GHG Emissions

Figure 6-12: GHG Profile for Wind System



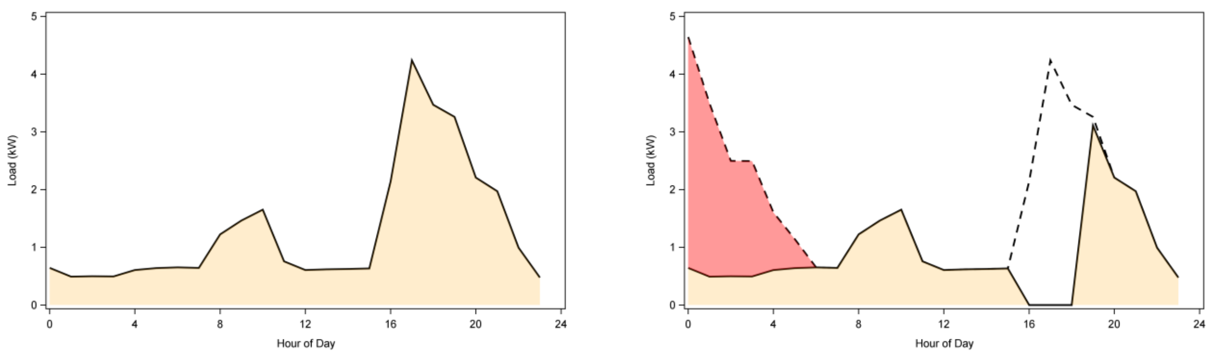
Wind systems generate electricity without consuming any fossil or biogas fuel. There is no emissions rate associated with electricity generation from wind systems. The rate at which wind systems avoid emissions is equal to that rate at which the grid generates emissions. Figure 6-12 shows the GHG impacts profile for a wind system during a representative week. The capacity factor shown in the top half displays the variability one might expect from a wind turbine. Unlike previous case studies, the lower half of this figure shows the total avoided tons of CO_2 during each hour (instead of tons per MWh). The tons of CO_2 avoided during each hour are proportional to the system's capacity factor. Higher capacity factors lead to greater amounts of avoided emissions. A wind turbine's capacity factor is dictated by the availability of the wind resource; appropriately locating the turbine in a high wind resource area is critical to maximizing the capacity factor.

Advanced Energy Storage – Shifting Load to Reduce GHG

In 2011, standalone (not coupled to SGIP systems or solar PV) advanced energy storage systems became eligible for incentives under the SGIP. Evaluating the GHG impact of storage systems requires an understanding of how the storage system is affecting the load. In this section we model a residential storage system that charges during the minimum load hours and discharges when loads are highest. This operating mode is more commonly referred to as peak shifting.

Figure 6-13 illustrates one potential scenario in which storage could reduce GHG emissions. Part (a) shows a representative electric load profile for a residential customer – a small peak is observed in the morning and a larger peak is seen in the afternoon and evening. A storage system that shifts this afternoon peak to hours when the marginal GHG emissions rate of the electricity grid is lower (cleaner) could reduce GHG impacts.

Figure 6-13: Residential Load with Peak-Shifting Storage



(a) Load Only
Total Energy Consumption: 31 kWh
CO_2 Emissions: 13.28 kg

(b) Load With Peak-Shifting Storage
Total Energy Consumption: 33.5 kWh
CO_2 Emissions: 13.23 kg

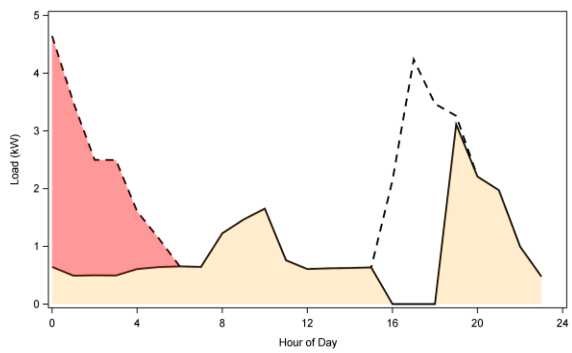
Part (b) of Figure 6-13 shows what the load profile could look like if a storage system were operating in peak-shifting mode. The battery would charge during early morning hours when the grid is relatively cleaner (red area) and discharge its energy to reduce energy consumption during the afternoon peak hours. Because of round-trip inefficiencies inherent in all battery technologies, the total energy consumption of the residence increases with the application of storage from 31.0 kWh to 33.5 kWh. Despite the increase in consumption, the emissions associated with this load profile have decreased slightly due to the shift in consumption to a period with a lower emissions rate. If this pattern were to repeat each day for an entire year, GHG impacts would equal 17 kg of CO_2 per year. To put this number in perspective, an average household[6] with two occupants will generate approximately 750 kg of CO_2 each year. The emissions avoided by the storage system are more than one order of magnitude smaller than the emissions from an average household.

The system in Figure 6-13 was assumed to have a roundtrip efficiency of 80%. The roundtrip efficiency is a measure of the losses in the storage system – the higher the efficiency the lower the losses. In other words, roundtrip losses increase the total amount of energy consumption at the site. Figure 6-14 shows the effect that roundtrip efficiency has on energy and GHG impacts. Part (a) on the left of the figure

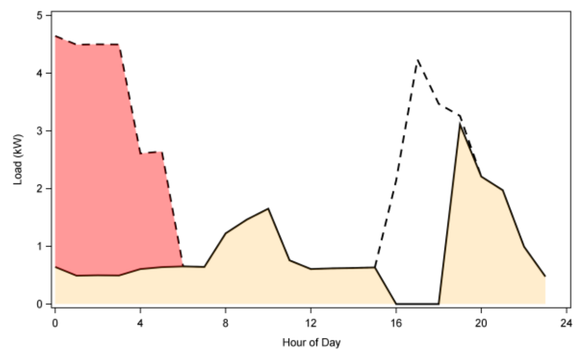
[6] http://www.epa.gov/climatechange/ghgemissions/ind-calculator.html

shows the net impacts of the system shown in Figure 6-13 – the roundtrip efficiency of the battery leads to an increase in consumption of 2.5 kWh. The net GHG impacts are negative (decreased GHG) because the benefit of shifting energy consumption to “cleaner” hours outweigh the effect of increased consumption.

Figure 6-14: Effect of Roundtrip Efficiency on Energy and GHG Impacts



(a) Residential Storage: 80% Roundtrip Efficiency
Net Energy Impact: +2.5 kWh
Net CO_2 Emissions: - 47 g



(b) Residential Storage: 50% Roundtrip Efficiency
Net Energy Impact: +10 kWh
Net CO_2 Emissions: + 2,698 g

Part (b) of Figure 6-14 shows the same system with 50% roundtrip efficiency. In this case, the total energy consumption for the day is significantly greater because the battery needs to consume more electricity to serve the same load later in the afternoon – this is manifested in the larger red area in the early morning. Because of this increased energy consumption, the system no longer achieves GHG reductions and actually increases emissions by almost 3 kg of CO_2 per day.

Key Takeaways:

1) ***As a result of recent program design changes, the composition of the future fleet of SGIP projects will be substantially different than what has been observed in previous years.***
2) ***Increased penetration of wind projects is expected–proper siting will be critical to maximize capacity factors and GHG emission reductions.***
3) ***Large quantities of residential storage projects exist in the SGIP queue. A storage system’s ability to achieve its GHG reduction potential remains unproven. Round trip efficiencies will be critical to understanding impacts.***

6.5 Valuing GHG Emissions and Future Outlook

In previous sections, it was shown that the SGIP successfully reduced GHG emissions in 2012. In this section the cost of these GHG impacts will be examined and the future outlook of SGIP GHG impacts is discussed.

Cost of GHG Emissions

Figure 6-15 summarizes the incentives associated with achieving net GHG reductions for the different DG technologies used in the SGIP. We developed "GHG reduction costs" that are proxy costs based on the cumulative incentives that have been paid for the specific technologies since the SGIP's inception. For comparison purposes, the cumulative incentives were distributed over ten years. Microturbines and internal combustion engines fueled by natural gas were excluded from Figure 6-15 because, on average, these technologies created a net increase in GHG emissions through 2012.

Figure 6-15: Program Costs of GHG Reductions by Technology[7]

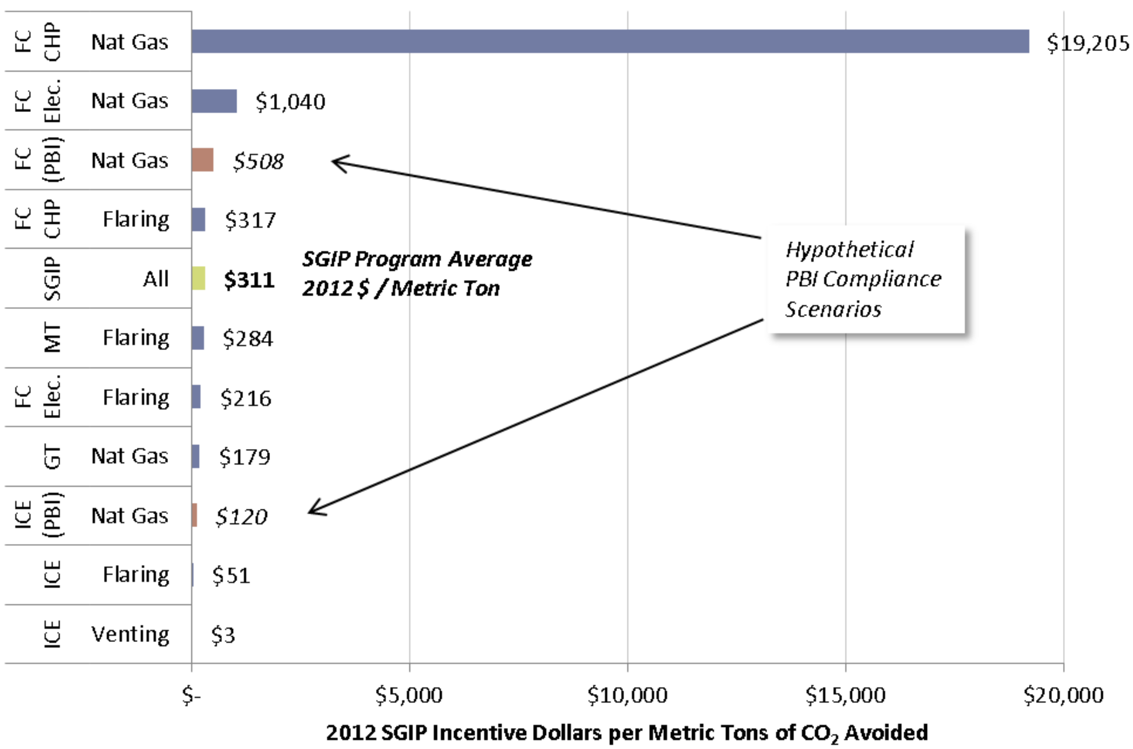


Figure 6-15 indicates several important points. First, it's important to recognize that in 2012, the SGIP was a net GHG reducing program, resulting in the reduction of over 128,000 metric tons of GHG (CO_2 eq.). Second, the figure provides information on technologies receiving incentives prior to the PBI guidelines and how these GHG cost reductions would look under the new PBI requirements that are specifically geared to reducing GHG emissions. In the case of non-renewable (i.e., natural gas based)

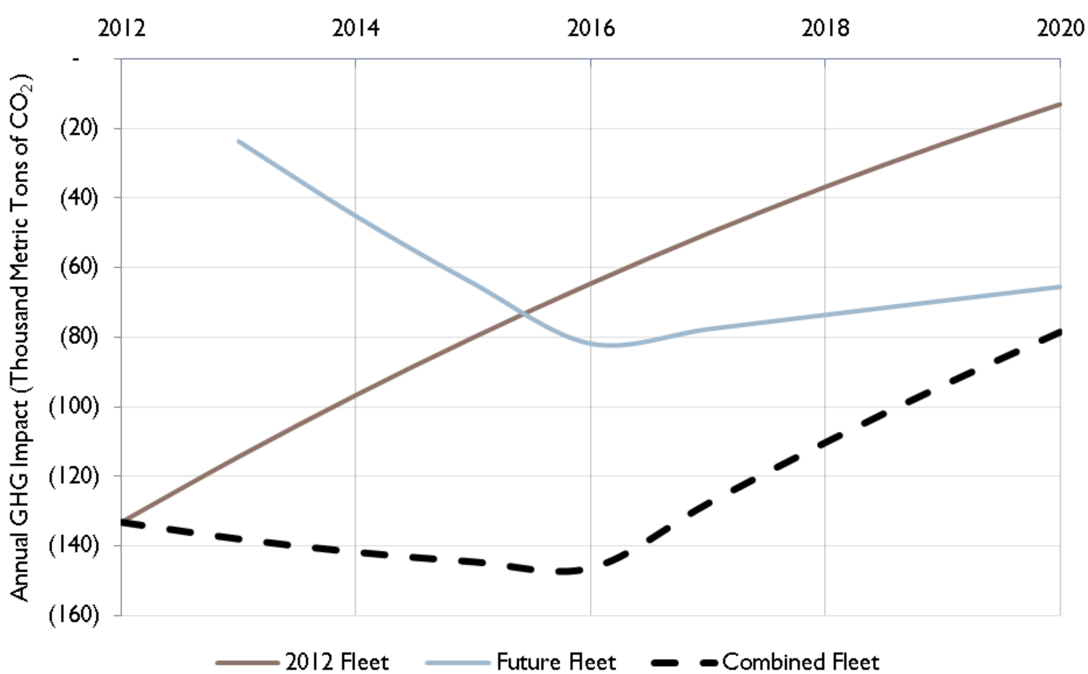
[7] The SGIP provides benefits in four areas; this represents the value only associated with GHG reductions.

fuel cells using waste heat recovery, the cost of achieving GHG emission reduction was fairly high. This high cost was largely due to the limited amount of waste heat recovered by the fuel cells and their electrical efficiencies being very close to the electrical efficiency of combined cycle power plants supplying grid electricity during most of the year. However, under the new PBI requirements, "CHP-fuel cells" would be required to recover higher rates of useful waste heat. Consequently, the cost of capturing GHG emission reductions would drop significantly from approximately $19,000 per metric ton to around $500 per metric ton. Similarly, under the pre-PBI conditions, non-renewable fueled internal combustion engines increased rather than reduced net GHG emissions. However, under the new PBI requirements, non-renewable (natural gas fueled) internal combustion engines should be achieving net GHG reductions at a cost of $120 per metric ton. Lastly, the SGIP had a range of GHG reduction costs. Internal combustion engines that avoid venting of renewable biogas required the least amount of program expenditures to achieve net GHG reductions at $3 per metric ton, while the SGIP spent on average $311 per metric ton of CO_2 reductions.

Future Outlook for GHG Impacts

Future projections of the electric, fuel, and thermal energy impacts of the SGIP through 2020 were presented in Section 4. These projections were based on both the SGIP fleet at the end of 2012 and the contents of the SGIP queue as it existed in April 2013. Figure 6-16 shows estimates of GHG impacts through 2020. Projected GHG impacts of projects completed by 2012 are shown in brown, the future impacts of projects in the queue are shown in blue, and the combined performance of the fleet (present and future) is shown in dashed black.

Figure 6-16: Projected SGIP GHG Impacts Through 2020

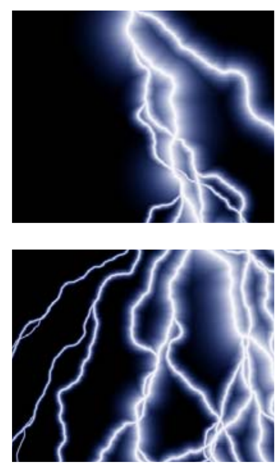


The GHG impacts of the 2012 fleet are projected to diminish from a reduction of 130 thousand metric tons of CO_2 in 2012 to about 80 thousand tons of CO_2 in 2020. This change is expected to occur for two reasons:

1. The performance of the 2012 fleet is expected to decline due to increased outages and decommissioning as systems age. Outages and decommissioning lead to decreased availability and diminishing GHG impacts.
2. The baseline conditions of the grid are expected to change through 2020. Specifically, the efficiency of the grid is assumed to increase due to regulatory requirements. This projection assumes a 1.4 percent increase in the efficiency of the grid (on the margin) per year.

The GHG impacts of the future fleet are projected to begin in 2013 at just over 20 thousand metric tons of CO_2 reductions and reach a maximum of just over 80 thousand metric tons of CO_2 reductions in 2016. GHG impacts are expected to increase (more reductions) through 2016 as more capacity is added each year. For this analysis we assumed that the SGIP is not extended and no new applications come in after December 31, 2015. Consequently, all projects in the SGIP queue were assumed to be completed by 2016, therefore the GHG impacts of the future fleet after 2016 are projected to remain flat.

The impacts of the combined fleet represent the sum of the 2012 fleet and the future fleet. Overall, the GHG impact of the SGIP is expected to diminish from a reduction of 130 thousand metric tons of CO_2 to just over 80 thousand metric tons of CO_2 reduced in 2020.



SGIP and Distributed Generation Market Transformation

7

7 SGIP AND DISTRIBUTED GENERATION MARKET TRANSFORMATION

In its September 2011 decision modifying the SGIP and implementing Senate Bill 412, the CPUC established market transformation as one of the four goals of the program.[1] Therefore, in assessing the sustainability of benefits being captured by the SGIP, we need to investigate the ability of the SGIP to help transform the DG market.

Market transformation involves more than driving technologies to a cost competitive stance. The American Council for an Energy-Efficient Economy (ACEEE) has defined market transformation of the energy efficiency market as *"the strategic process of intervening in a market to create lasting change in market behavior by removing identified barriers or exploiting opportunities to accelerate the adoption of all cost-effective energy efficiency as a matter of standard practice."*[2] Making distributed energy technologies a sustainable part of the energy landscape requires the presence of active market players who can respond effectively to marketplace needs and opportunities, and an environment conducive to DER growth.[3]

This section presents a discussion of the relationship between the costs and benefits under the SGIP. Results from the 2011 SGIP cost-effectiveness study on DG technologies,[4] as well as policy drivers that will help support future cost reductions, are discussed.

7.1 Distributed Generation Cost-Effectiveness

Reducing DG Costs and Increasing Benefits

Earlier in this study we examined the value of achieving peak demand relief and GHG emission reductions from the SGIP. In general, the SGIP achieved these benefits at certain levels of 'costs,' measured as the amount of incentives provided through the program. In assessing any type of benefits-to-cost ratio, it must be remembered that the SGIP is required to achieve multiple goals. Unlike demand reduction programs that have been specifically constructed to achieve demand reductions at low costs, the SGIP achieves demand reduction as only one of four goals. Similarly, while achieving GHG emission reductions is one of the primary goals of the SGIP, the SGIP garners multiple benefits along the way of achieving GHG.

As costs of SGIP technologies drop, we expect incentives to also decrease. This expectation is reflected in the program by incentive rates that decline annually.[5] Similarly, as shown in our assessment of future

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[1] In particular, SGIP is to assist in market transformation of distributed energy resource (DER) technologies. See CPUC Decision D.11-09-015, September 8, 2011.

[2] http://aceee.org/portal/market-transformation

[3] In Decision D.11-09-015, the CPUC expands cost-effectiveness in determining eligibility of SGIP applications to include technologies that show the potential to be cost-effective in the future. Within this study, we are using cost-effectiveness as a way to measure market transformation.

[4] "CPUC Self-Generation Incentive Program: Cost-Effectiveness of Distributed Generation Technologies," Itron, February 9, 2011.

[5] Incentives for emerging technologies decline 10% per year; all other technologies decline 5% per year.

GHG emission and peak demand reductions, we expect the magnitude of the benefits to remain the same or increase. Moving into the future, the SGIP will achieve higher benefit-to-incentives values for the achieved GHG or peak demand reductions.

How does SGIP result in market transformation of the DG industry? Ideally, SGIP incentives help support an increase in the demand for DG technologies. The increased demand causes increased production, with associated improvements to the efficiency with which the technology is produced and, potentially, an increase in the technology performance. The improvement in efficiency of production should lead to reduced prices and a self-sustaining market place. Although the California market for DG is insufficient in size to be wholly responsible for any market transformation effects, the California DG market can expect that a certain amount of market transformation will occur, particularly at the engineering, design, and construction steps in the value chain.

In 2011, Itron investigated the cost-effectiveness of DG technologies currently eligible for SGIP.[6] As part of the cost-effectiveness study, we modeled the market transformation effects of the SGIP program on the future costs of DG technologies.[7] The developed model (SGIPce model) allowed cost-effectiveness to be looked at on a prospective, and not just retrospective, basis.

Incorporating market transformation into the SGIPce model meant assessing historical cost reductions in DG technologies attributable to increased global production. It required the incorporation of recent historical information on technology prices and sales volumes and an assessment of technology development that may occur in the future. In turn, this information was used to examine how increased volumes of sales in California, and around the world, may contribute to future changes in prices attributable to improvements in technology or manufacturing processes.

We modeled the prospective cost-effectiveness and the market transformation benefits of DG technologies based on "learning curves." Learning curves use the premise of "learning by doing." As a new technology is developed, manufactured, and shipped, future units (holding all other inputs constant) will cost less to produce due to improved learning. Based on the maturity of the technology and worldwide distribution, learning curves start with the assumption that costs will decrease at particular rates as the volume of worldwide sales double. We applied this concept through the development of progress ratios, which were incorporated into the SGIPce model: A progress ratio of 1 represents no change in the cost of the system over time, regardless of how many units are manufactured. In essence, there is no "learning by doing." A progress ratio of 0.8 indicates that, based on projected worldwide shipment volumes, the cost of the unit will be reduced by 20% with doubling of the worldwide volumes. Within the SGIPce model, the progress ratio was applied on a year-by-year basis.

Progress ratios and worldwide volume estimates were derived for each examined DG technology based on research including analysis of financial data, material content of the technology, maturity of the technology, interviews with manufacturers, and other published research. As acknowledged in the CPUC cost-effectiveness decision, "…any market transformation analysis will involve scenario analysis

[6] "CPUC Self-Generation Incentive Program: Cost-Effectiveness of Distributed Generation Technologies," Itron, February 9, 2011

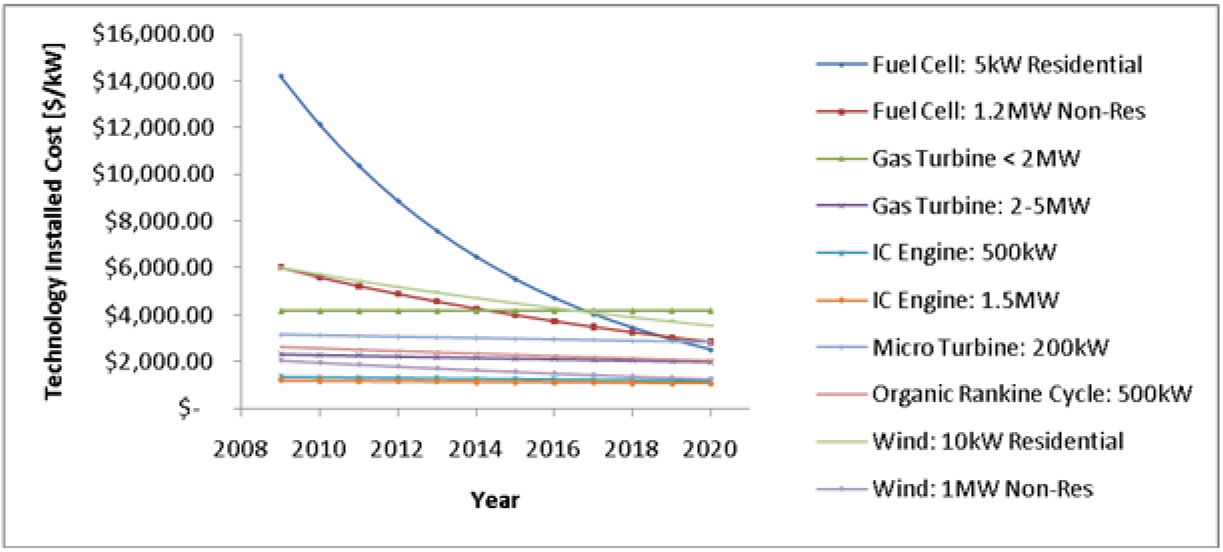
[7] The SGIP cost-effectiveness model (called SGIPce) is available at: http://www.cpuc.ca.gov/PUC/energy/DistGen/sgip/proposal_workshops.htm

and a host of assumptions. Among other things, these assumptions will likely include varying levels of future total installation costs for DG."[8]

Future DG Costs: DG Learning Curve Results

Figure 7-1 summarizes the DG learning curve results that were developed under the DG cost-effectiveness study for the examined technologies. As expected, less mature DG technologies show steeper and more pronounced learning curves than more mature technologies. However, nearly all the DG technologies showed some amount of future cost reductions.

Figure 7-1: Distributed Generation Learning Curves

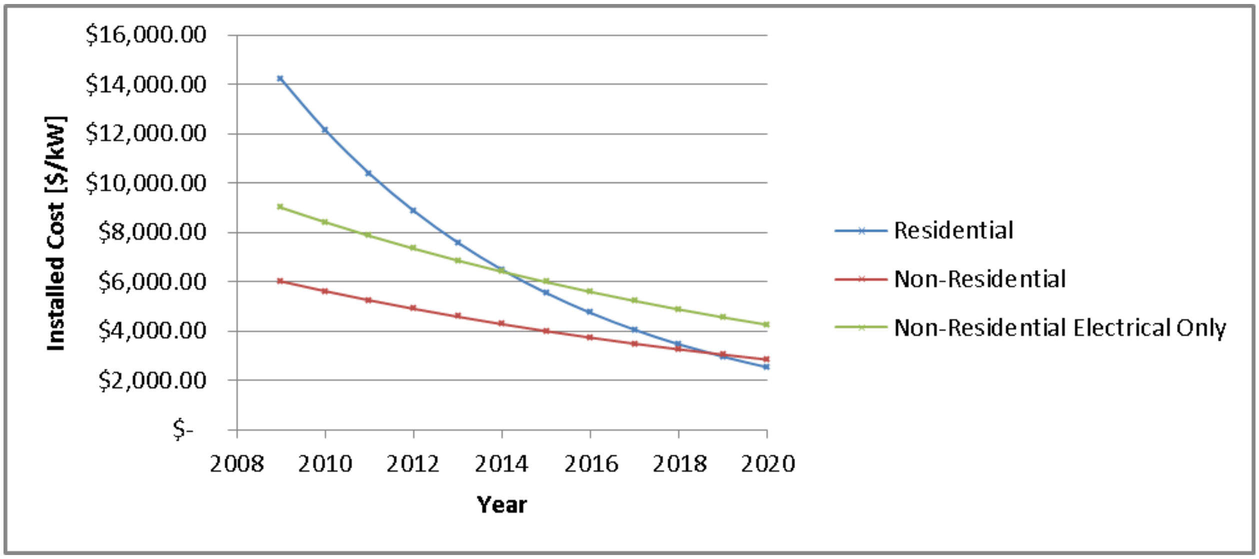


Source: Itron

In Section 3 (Background and Status), we note that the SGIP queue going into 2012 and later is made up of a significant amount of fuel cell and storage technologies. Because these are also newly emerging technologies, it's instructive to examine the individual learning curves for these technologoies. Figure 7-2 shows the predicted effect of leaning curves on the capital costs of residential and non-residential fuel cells. Based on production volumes and cost reductions achieved to date, fairly steep reductions in fuel cell costs could be expected in the future.

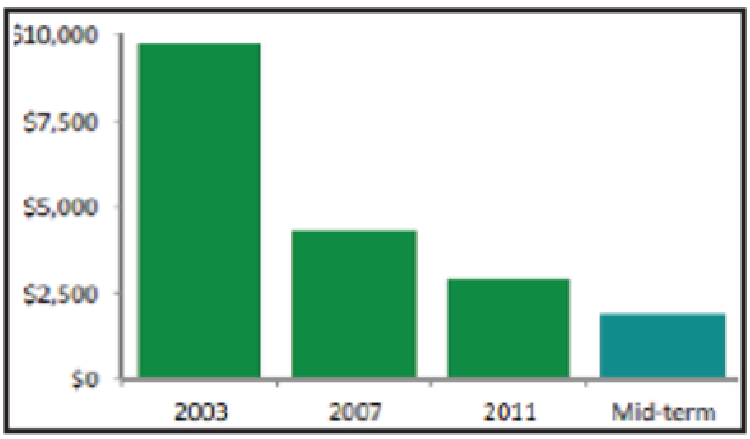
8 http://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/105926.pdf page 44.

Figure 7-2: Effect of Learning Curves on Fuel Cell Capital Costs



Outside sources also show significant cost reductions occuring for fuel cell technologies and continued reductions projected for the future. Figure 7-3 shows historical cost trends for stationary fuel cells.[9]

Figure 7-3: Historical Cost Trends for Stationary Fuel Cells



Source: DOE

There are a number of advanced energy storage technologies developing in the marketplace. Figure 7-4 is a summary of estimated capital costs and levelized costs for storage technologies suitable for use with distributed energy applications.[10] Li-ion batteries appear to be a likely battery choice for electric and

[9] "2011 Fuel Cell Technologies Market Report," Department of Energy, July 2012

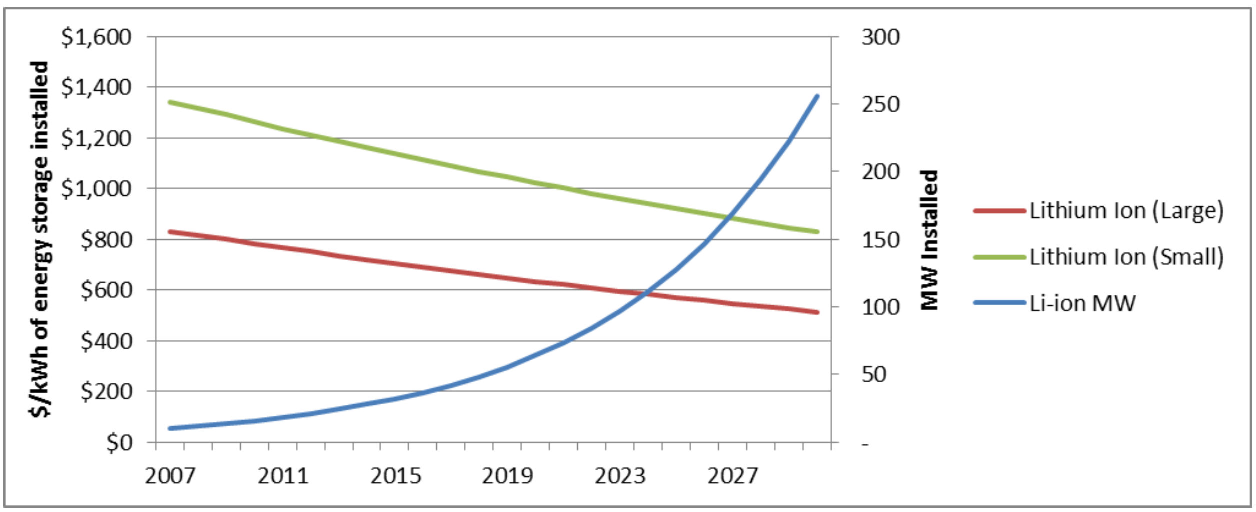
[10] "Electricity Energy Storage Technology Options: A White Paper Primer on Applications, Costs and Benefits," Electric Power Research Institute, December 2010

hybrid electric vehicles. As such, large-scale volume production may lead to faster reductions in costs. Figure 7-5 represents projected costs of Li-ion battery technologies out through 2027.[11]

Figure 7-4: Estimated Costs of Distributed Storage Technologies[12]

Applications: • Distributed Energy Storage at Pad-Mounted Transformer • Distribution Deferral; Peak Shaving • Reliability • Dual-Mode Frequency Regulation							
Technology Option	**Maturity**	**Capacity (kWh)**	**Power (kW)**	**Duration (hrs)**	**% Efficiency (total cycles)**	**Total Cost ($/kW)**	**Cost ($/kW-h)**
Advanced Lead-Acid	Demo-Commercial	100-250	25-50	2-5	85-90 (4500)	1600- 3725	400-950
Zn/Br Flow	Demo	100	50	2	60 (>10000)	1450-3900	725-1950
Li-ion	Demo	25-50	25-50	1-4	80-93 (5000)	2800-5600	950-3600

Figure 7-5: Projected Costs of Li-ion Storage



Improvements in manufacturing result in learning curves that drive down capital costs, thereby making technologies more economically attractive and increasing market adoption. However, government policies also affect market growth of technologies. Due to its leadership position in energy and the environment, Calfornia's policies can play a strong role in the adoption of DG technologies in the future.

[11] "CPUC Self-Generation Incentive Program: Cost-Effectiveness of Distributed Generation Technologies, Appendix A" Itron, February 9, 2011

[12] Source: IEPR, 2010

Policy Drivers

Within California, existing programs such as the SGIP, CSI, Feed-in-Tariff and utility PV programs support DG development on both the customer and utility side.[13] Moving forward, the Governor's Clean Energy Jobs Program calls for the addition of 12,000 MW of new localized DG by 2020, and 6,500 MW of CHP by 2030.[14] The same program calls for utilities to procure 5% of their peak demand needs via energy storage technologies. At the federal level, the President's Executive Order on Industrial Energy Efficiency has established a national goal of 40 GW of new CHP by 2020.[15] Market forces will act to pull forward DG and CHP growth in California, while federal and state policies will help push it forward.

Climate change policies will be another critical factor affecting adoption of DG technologies in California. In 2005, Governor Schwarzenegger established Executive Order S-3-05 requiring the state to reduce GHG emissions to 2000 levels by 2010, to 1990 levels by 2020, and 80% below 1990 levels by 2050.[16] In 2006, the legislature passed AB 32 (the Global Warming Solutions Act of 2006) mandating that the state reduce GHG emissions to 1990 levels by 2020.[17]

The road map for implementing California's climate change policies is contained in the Climate Change Scoping Plan.[18] In accordance with the Scoping Plan, GHG emissions from California's electricity sector must be reduced by 30% over the Business as Usual scenario to achieve the 2020 goals. Table 7-1 reflects the levels of GHG emission reductions called for from the electricity sector under the Scoping Plan.

Table 7-1: Electricity Sector 2020 GHG Emission Reductions

AB 32 Strategies	*GHG Reductions (MMT CO_2Eq)*
Energy Efficiency	26.3
- Building/Appliances	19.5
- Increased CHP	6.7
- Solar Water Heating (AB 1470)	0.1
RPS (33% by 2020)	21.3
Million Solar Roofs (CSI)	2.1
Total:	**49.7**

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13 http://www.cpuc.ca.gov/PUC/energy/DistGen/

14 http://gov.ca.gov/docs/Clean_Energy_Plan.pdf

15 http://www.whitehouse.gov/the-press-office/2012/08/30/executive-order-accelerating-investment-industrial-energy-efficiency

16 http://www.casfcc.org/2/StationaryFuelCells/PDF/Executive%20Order%20S-20-06.pdf

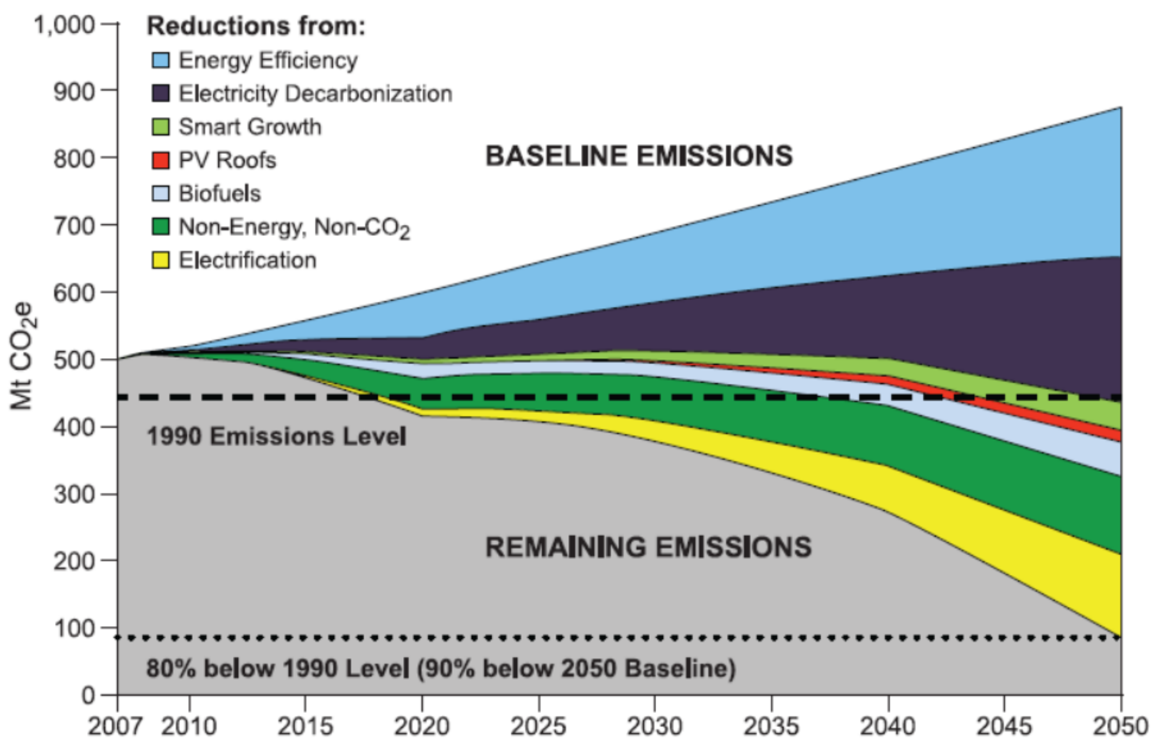
17 http://www.leginfo.ca.gov/pub/05-06/bill/asm/ab_0001-0050/ab_32_bill_20060927_chaptered.pdf

18 "Climate Change Scoping Plan," California Air Resources Board, December 2008

According to the Scoping Plan, capturing 6.7 Million Metric tons (MMT) of CO_2 equivalent emission reductions from CHP requires the addition of 4,000 new MW of CHP systems capable of displacing approximately 30,000 GWh of electricity demand from grid resources.[19]

To date there is no official requirement for achieving the 80% reduction by 2050 goal set out in the 2005 Executive Order. However, analyses by Lawrence Berkeley National Lab (LBNL) suggest that major new technology advances will be required to achieve the 2050 target.[20] Figure 7-4 summarizes the strategies identified by LBNL for California to achieve the 2050 GHG emission reduction goal. Among the strategies include 90% of the state's electricity generation coming from carbon free sources, and 10% of electricity demand being met by rooftop solar PV.

Figure 7-4: Strategies for Achieving 2050 GHG Emission Reductions



There is also increasing concern over climate change impacts at the federal level. In June, President Obama released an Action Plan containing specific objectives to achieve the targeted 17% reduction below 2005 levels by 2020.[21] Among the specific objectives are a doubling of renewable energy generation at the national level by 2020, increasing energy efficiency efforts in the multifamily arena, and expanding electric vehicle deployment. Overall, the net effect will be an increasing emphasis on developing additional clean energy resources that help to reduce GHG emissions.

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[19] Ibid, page 44

[20] "The Technology Path to Deep Greenhouse Gas Emission Cuts by 2050: The Pivotal Role of Electricity," Williams, James H., et. al., Science, January 6, 2012

[21] "The President's Climate Action Plan," Office of the President, June 2013

> ***Key Takeaways:***
>
> 1) ***Assisting in market transformation of distributed generation technologies is one of the four primary goals of the SGIP.***
> 2) ***SGIP helps in DG market transformation by leading to increased production of DG technologies with associated improvements to the efficiency with which the technologies are produced (i.e., "learning curves"). Cost modeling of DG technologies shows that DG costs can be expected to decrease moving into the future.***

7.2 SGIP Current and Future Market Potential

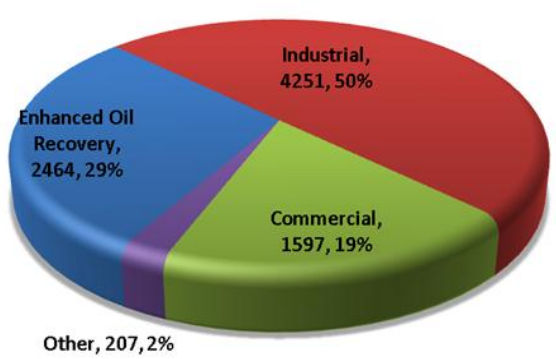
While a number of new DER technologies are beginning to appear in the SGIP, CHP remains a major part of the program. In addition, new CHP applications to SGIP indicate that CHP is likely to continue being a strong component in the SGIP. Consequently, it's important to look at the current CHP market in California and how it may change in the future.

California's Current and Potential CHP Markets

Several past studies have examined California market potential for CHP.[22,23,24,25] One of the most recent studies conducted in 2012 by ICF International examines the technical potential of CHP in California.[26]

ICF's 2012 report provides a good breakout of existing CHP installations in California. ICF estimates that there are some 1,200 CHP systems installed in California, representing over 8,500 MW of capacity. The vast majority (85 percent) of California's installed CHP capacity is greater than 20 MW in size. As shown in Figure 7-9, industrial sector applications account for nearly 50% of the installed CHP capacity, while commercial applications account for 19%.

Figure 7-5: California's Existing CHP Capacity



Source: ICF

While the SGIP provides incentives to CHP projects in both the industrial and

[22] "Market Assessment of Combined Heat and Power in the State of California," Prepared by Onsite Systems Energy for the California Energy Commission, P700-00-009, October 2000.

[23] "Assessment of California CHP Market and Policy Options for Increased Penetration," Prepared by the Electric Power Research Institute for the California Energy Commission, CEC 500-2005-060, April 2005.

[24] "Preliminary Estimates of Combined Heat and Power Greenhouse Gas Abatement Potential for California in 2020," Prepared by the Lawrence Berkeley National Lab for the California Energy Commission, July 2007.

[25] "Combined Heat and Power Market Assessment," Prepared by ICF International for the California Energy Commission, CEC 500-2009-094, October 2009.

[26] "Combined Heat and Power: Policy Analysis and 2011-2030 Market Assessment, Prepared by ICF International for the California Energy Commission, CEC-200-2012-002, February 2012.

commercial sectors, projects have historically been sized at 5 MW and below.[27] Within the industrial sector, three market segments have high technical potential in the smaller than 5 MW size range: paper manufacturing, food processing and the chemical industry.

Figure 7-6: Industrial Sector CHP Potential by Segment and Size (MW)

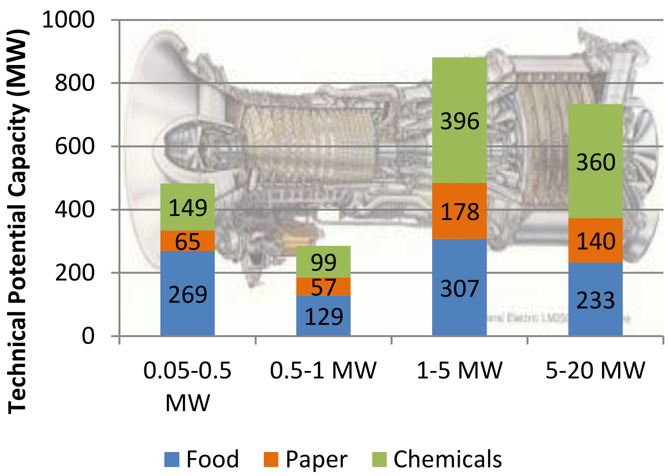
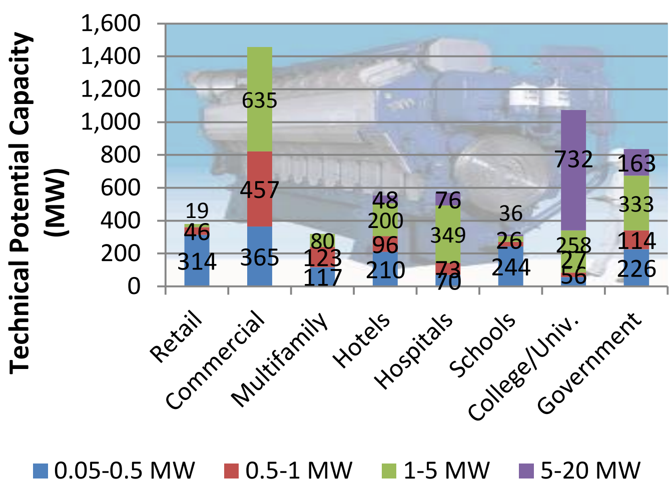


Figure 7-10 shows a breakdown of CHP technical potential in the industrial sector by market segment and CHP system size.

Within the three industrial segments that are applicable to SGIP projects, there is 483 MW of potential in the less than 500 kW size range, 285 MW within the 500 kW to 1 MW size range, and over 880 MW of potential in the 1 to 5 MW size in range - for a total potential of 1,649 MW. Industrial operations tend to have high and consistent thermal and electrical loads, making them good candidates for baseload generation technologies, such as gas turbines and fuel cells.

Figure 7-7: Commercial Sector CHP Potential by Segment and Size (MW)



Within the commercial sector, eight market segments show high technical potential in the smaller than 5 MW size range. Figure 7-11 shows a breakdown of the eight commercial market segments by size. There is approximately 1,600 MW of technical potential in the size range smaller than 500 kW, an estimated 960 MW in the 500 kW to 1 MW size range, and over 1,900 MW of potential in the 1 to 5 MW size range - for a total technical potential of approximately 4,500 MW.

California clearly has significant CHP potential that can be developed in the small-scale range suitable for the SGIP. The combination of decreased costs through learning curves and increased useful waste heat recovery rates will help make CHP technologies more economically attractive. Blending of CHP systems with storage can also help improve the ability of these technologies to better address peak demand needs within the electricity distribution system. Lastly, the ability of

[27] Note that the 2011 SGIP decision removed system size limitations, provided the system is sized to onsite load.

SGIP technologies to reduce GHG emissions may play a critical role in their market adoption if concerns over climate change increase.

We started this section noting that the SGIP is a multiple purpose program, with market transformation being one of those primary goals. By supporting and encouraging the deployment of DG technologies in a utility setting, the SGIP enables learning by both the DG industry and utilities, which ultimately results in technology improvements and cost reductions. Reductions in DG technology costs and improvements in operations resulting from the SGIP will play an increasingly important role in the transformation of the DER market and positioning California's electricity sector to move to a smart grid platform and achieve the state's future GHG emission goals.

Key Takeaways:

1) ***There is large and unmet potential for DG and CHP technologies in California. Decreasing DG costs will act as market drivers to increased DG growth. In turn, state and federal policies on renewables, climate change and CHP will help spur additional growth and advancement in DG technologies.***
2) ***One example of how SGIP may influence DG market transformation is through increased improvements and efficiency of CHP technologies. The combination of decreased costs through learning curves and increased useful waste heat recovery rates will help spur development of CHP technologies in the commercial and industrial sectors.***

Appendix A

APPENDIX A
SOURCES OF DATA AND PROGRAM STATISTICS

A.1 Overview

This appendix provides details on the sources of data and program statistics. First, the primary sources of data used in this impact evaluation are discussed. Second, the detailed program statistics are provided in various permutations. We examine the overall program status, projects in the queue, program trends, and project statistics by Program Administrator (PA) and conclude with incentive and participation trends. The statistics are divided by technology type and fuel type. The technologies include advanced energy storage, fuel cells, gas turbines, internal combustion engines, microturbines and wind turbines. The fuel types are broken down into a natural gas category, renewable (biogas) category and a no-fuel category.[1]

Nomenclature for Reporting Program Results

Self-Generation Incentive Program (SGIP) projects fall into different status categories depending on their position relative to the application process. For SGIP impact reporting purposes, we only consider projects that have received incentive payment checks. These "complete" projects are interconnected into the electricity system, are assumed to have entered "normal" operation, and as such have impacts. We classify complete SGIP projects into two categories for program impact reporting purposes. Complete SGIP projects are grouped into Program Year (PY) to help associate them with specific SGIP Handbook requirements or to connect them with other time-specific requirements (e.g., legislative or environmental regulations). When grouping complete SGIP projects by Program Year, the application date is used to determine their Program Year. Conversely, complete SGIP projects are grouped by Calendar Year (CY) to identify when the impacts occur. We use the "check issued" date (i.e., incentive payment date) to group complete SGIP projects by Calendar Year. Throughout this SGIP impact evaluation, results are reported in Calendar Year unless specifically stated otherwise.

Project Definitions

We categorized the status of SGIP projects into three groups according to their stage of progress within the SGIP implementation process: Active projects, Inactive projects, and Complete projects. Program Administrators use significantly more classifications in defining project stages in the implementation process. However, for the purpose of grouping SGIP projects to assess impacts, we have stayed with a more general set of classifications.

Active projects have applied for a rebate and are in the queue working through the program requirements needed to receive an incentive payment. These represent SGIP projects that have not been withdrawn, rejected, completed, or placed on a waiting list. Over time, Active projects will migrate either to the Complete or to the Inactive category.

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[1] While PV projects were eligible to apply for SGIP incentives up through January 1, 2007, and PV projects received SGIP incentives in the past, all impacts due to SGIP PV projects are not reported in the SGIP impact evaluation but are instead reported in the California Solar Initiative impact evaluations.

Inactive projects consist of SGIP projects that are no longer making forward progress in the SGIP implementation process. These projects have been withdrawn, rejected or cancelled by the applicant or the PA.

Complete projects represent SGIP projects for which the generation system has been installed, the system installation verified through an on-site inspection, and an incentive payment has been issued. The impacts evaluation is conducted on all projects in the Complete category.

The operational status of SGIP projects is also important. We define and classify the operational status of SGIP projects in Section A.3 (Program Statistics) below.

A.2 Sources of Data

There are three primary sources of data for this impact evaluation:

1. Statewide SGIP Project List
2. Monitoring Plans and Installation Verification Site Visit Reports
3. Metered Data.

Statewide SGIP Project List

The PAs maintain a tracking database that has information on projects that have applied to the program and are in various stages of the application process. Projects that have applied for and received an incentive payment are classified as complete projects. Projects that have applied and are in an intermediary processing stage are considered active projects. Projects that have been withdrawn, rejected or cancelled are considered inactive. The PAs provide data on application date, technology type, fuel type, rebated capacity, project location, incentive reserved and eligible project costs that are collected as part of the application package.

Monitoring Plans and Installation Verification Site Visit Reports

The PAs hire independent consultants who verify that a project has been installed as described in the application. Site visit reports and results are compiled and provided by the PAs. In addition, Itron engineers may conduct site visits and prepare site specific monitoring plans needed to implement data collection and project monitoring. At these site visits the engineers verify and document meter numbers, nameplate ratings, location and type of metering devices, and if the system is operational, the date the system entered normal operation.

Metered Data

Metered data are gathered from many SGIP host sites and made available from the PAs, the host, or a third party data gatherer. The metered data collected are the electric net generator output (ENGO), useful thermal energy (HEAT), and fuel use (FUEL). These data are used to conduct annual impact analyses such as that reported here.

Electric Net Generator Output (ENGO) Data

ENGO data describe the net amount of electricity generated by the metered SGIP system in a specific time period, typically a 15-minute interval. This information is needed to assess annual and peak electricity contributions from SGIP projects. ENGO data are collected from a variety of sources, including meters that Itron installs on SGIP systems under the direction of the PAs and meters installed by project Hosts, Applicants, electric utilities, or third parties.

Useful Thermal Energy (HEAT) Data

Useful thermal energy data describe the heat captured in a specific time period, typically a 15-minute interval, by heat recovery equipment of the SGIP systems and used at the site to satisfy heating and/or cooling loads. Useful thermal energy (also referred to as HEAT) data are used to assess compliance of SGIP cogeneration[2] systems with required levels of efficiency and useful waste heat recovery. In addition, useful thermal energy data for SGIP systems enable estimation of baseline boiler natural gas fuel and electric chiller electricity consumption that in the absence of the SGIP system would be satisfied by the utility companies. This information is used to assess energy efficiency impacts as well as to calculate GHG emission impact estimates. Heat data are collected from heat metering systems installed by Itron as well as heat metering systems installed by Applicants, Hosts, or third parties.

Fuel Usage (FUEL) Data

Fuel usage (also called FUEL) data describe the natural gas fuel consumption of SGIP systems in a specific time period. Most received fuel data are reported for time intervals much greater than one hour (e.g., daily or monthly). In most instances hourly fuel consumption within these intervals is estimated based on the associated hourly metered ENGO value. Fuel data are used in the impact evaluation to determine overall system efficiencies of SGIP cogeneration facilities, to determine compliance of renewable fuel use facilities with renewable fuel use requirements, and to estimate GHG emission impacts. Fuel data are obtained mostly from fuel metering systems installed on SGIP systems by natural gas utilities, SGIP participants, or by third parties.

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[2] SGIP cogeneration systems (also referred to as combined heat and power systems) are those required to recover and use waste heat. Renewable fuel fired systems and very high efficiency fuel cells are not required to recover waste heat. The complete set of waste heat requirements are specified in Section 9.4 of the 2012 SGIP Handbook.

A.3 Program Statistics

Statistics by Technology, Fuel and Operational Characteristics

Table A-1 shows the technology type distribution of SGIP projects by number of projects and rebated capacity in megawatts for 2012. Overall, there were 617 projects representing 294 MW of rebated capacity. IC engines accounted for the largest number of projects and highest total rebated capacity.

Table A-1: Status by Technology Type, Rebated Capacity, and Project Count (2012)

Technology Type	*Number of Projects*	*Rebated Capacity (MW)*	*Percent of Total Rebated Capacity*
Advanced Energy Storage	2	2	0.5%
Fuel Cells - CHP	103	24	8.1%
Fuel Cells - Electric Only	92	46	15.8%
Gas Turbines	9	30	10.2%
IC Engines	256	156	53.2%
Microturbines	141	26	8.7%
Wind Turbine	14	10	3.5%
Total	**617**	**294**	**100%**

Table A-2 shows the distribution of project and rebated capacity by fuel type used. Natural gas is the dominant fuel used in the program and is used in over 75% of the rebated capacity.

Table A-2: Status by Fuel Type and Technology: Rebated Capacity and Project Count (2012)

Fuel Type and Technology		*Number of Projects*	*Rebated Capacity (MW)*	*Percent of Total Rebated Capacity*
No Fuel	Advanced Energy Storage	2	2	0.5%
	Wind Turbine	14	10	3.5%
Renewable (Biogas)	Microturbine	22	5	1.5%
	IC Engine	25	15	5.0%
	Fuel Cell	73	41	13.8%
Natural Gas	Microturbine	119	21	7.1%
	IC Engine	231	142	48.1%
	Fuel Cell	122	30	10.0%
	Gas Turbine	9	30	10.5%
Total		**617**	**294**	**100%**

Table A-3 details the operational status of SGIP projects at the end of 2012. “Operational” projects are those connected to the grid and providing power. Some of the operational projects may be temporarily down or off for various reasons such as maintenance or repair. “Decommissioned” projects are those where the SGIP system has been retired and the equipment removed from the project site.[3] “Off-line” projects are defined as those having a 2012 annual capacity factor less than 0.05. There are also projects for which we do not know the operational status because the project applicants are no longer traceable. These projects are lumped into the Unknown category. Of the total 617 projects and 294 MW of rebated capacity at the end of 2012, 28% of the projects representing 22% of the rebated capacity were offline or decommissioned.

Table A-3: Operational Status of Complete Projects by Technology (2012)

Technology	Online			Decommissioned			Offline			Unknown		
	Project Count	*Rebated Capacity (MW)*	*Percent of Total Rebated Capacity*	*Project Count*	*Rebated Capacity (MW)*	*Percent of Total Rebated Capacity*	*Project Count*	*Rebated Capacity (MW)*	*Percent of Total Rebated Capacity*	*Project Count*	*Rebated Capacity (MW)*	*Percent of Total Rebated Capacity*
Fuel Cells	166	57.5	20%	9	2.3	1%	6	2.5	1%	14	7.8	3%
IC Engines	85	55.4	19%	*40*	17.5	6%	53	34.8	12%	78	48.7	17%
Gas Turbines	8	28.8	10%	-	0.0	0%	-	0.0	0%	1	1.4	0%
Microturbines	47	10.8	4%	24	3.7	1%	42	4.8	2%	28	6.2	2%
Advanced Energy Storage			0%			0%			0%	2	1.6	1%
Wind Turbine			0%			0%			0%	14	10.0	3%
Total	**306**	**152.5**	**52%**	**73**	**23.6**	**8%**	**101**	**42.1**	**14%**	**137**	**75.7**	**26%**

[3] SGIP projects are not required to report a decommissioned status. Generally, we discover systems have been decommissioned when we call the customer or applicant to check why the project is not showing fuel consumption or electricity generation.

Table A-4 shows the projects in the queue and the distribution by technology type as of April 12, 2013. Fuel cells, advanced energy storage projects, wind turbines, gas turbines and IC engines make up the vast majority of the technologies in the queue.

Table A-4: Reserved Project Status (April 12, 2013)

Technology	*Project Count*	*Rebated Capacity (MW)*	*Percent of Total Rebated Capacity*
Advanced Energy Storage	641	27.49	19%
Fuel Cells CHP	10	2.92	2%
Fuel Cells Electric	81	45.31	32%
Gas Turbines	3	18.04	13%
IC Engines	20	21.75	15%
Microturbines	14	6.91	5%
Pressure Reduction Turbines	6	1.90	1%
Waste Heat to Power	1	0.05	0%
Wind	10	18.90	13%
Total	**786**	**143.26**	**100%**

Trends

The tables above provide program and project statistics for calendar year 2012. It is also important to understand how SGIP statistics have changed over time. Table A-5 is a summary of project counts and rebated capacities of SGIP technologies by calendar year from 2002 to the end of 2012, as well as running cumulative totals. Table A-6 provides additional information by including both technology and fuel type in the breakout.

Table A-7 is a summary of projects count and rebated capacity of SGIP technologies by Program Year (PY01-PY11). Table A-8 provides additional information by showing the technology and fuel type breakout by Program Year.

Note that Table A-5 and Table A-6 include PV projects. PV projects were eligible to apply for SGIP incentives up through January 1, 2007. While PV projects could not apply for SGIP incentives as of January 1, 2007, legacy projects that had applied prior to that date, but had not reached the "check-issued" phase show up in calendar years 2007 through 2009. In addition, if PV project counts and rebated capacities are subtracted from the respective grand totals listed in Table A-5, the results provide the same 2012 values shown in Table A-2 (within the rounding error).

Table A-5: Annual and Cumulative Project Counts and Rebated Capacities by Technology (2002 – 2012)[4]

	PV		*AES*		*Wind Turbine*		*Fuel Cells*		*Gas Turbines*		*IC Engines*		*Microturbines*		*Total*	
Year	*Project Count*	*Rebated Capacity (MW)*	*Project Count*	*Rebated Capacity (MW)*	*Project Count*	*Rebated Capacity (MW)*	*Project Count*	*Rebated Capacity (MW)*	*Project Count*	*Rebated Capacity (MW)*	*Project Count*	*Rebated Capacity (MW)*	*Project Count*	*Rebated Capacity (MW)*	*Project Count*	*Rebated Capacity (MW)*
2002	17	2.0					1	0.20			6	4.0	3	0.3	27	6.4
2003	99	12.6									35	22.2	21	2.5	155	37.2
2004	161	16.3					1	0.60	1	1.4	51	35.2	25	3.9	239	57.4
2005	207	24.7			2	1.6	3	1.75	1	1.2	31	19.4	33	5.3	277	54.1
2006	155	25.5					7	3.95	2	9.0	62	36.3	27	5.0	253	79.7
2007	145	28.8					2	1.50	1	1.4	23	12.7	14	1.7	185	46.1
2008	96	22.7					6	3.90	1	4.6	20	13.5	11	3.5	134	48.1
2009	10	3.2			2	0.3	5	2.80	2	8.1	9	4.7	3	1.7	31	20.7
2010					4	2.8	12	4.16			12	5.3	2	0.3	30	12.6
2011					2	2.1	98	24.15			6	3.0	1	0.8	107	30.0
2012			2	1.6	4	3.6	60	27.13	1	4.4	1	0.3	1	0.8	69	37.8
Total	**890**	**135.8**	**2**	**1.6**	**14**	**10.3**	**195**	**70.1**	**9**	**30.1**	**256**	**156.5**	**141**	**25.5**	**1507**	**430.0**

4 Although the SGIP formally began in 2001, the first projects to reach Complete status occurred in 2002.

Table A-6: Annual Project Counts and Rebated Capacities by Technology and Fuel Type (2002 – 2012)

Year	PV		AES		Wind		Fuel Cells				Gas Turbines		IC Engines				Microturbines					
	Solar		No Fuel		Wind		Natural Gas		Biogas		Natural Gas		Natural Gas		Biogas		Natural Gas		Biogas		Totals	
	Project Count	Rebated Capacity (MW)	Project Count	Rebated Capacity (MW)	Project Count	Rebated Capacity (MW)	Project Count	Rebated Capacity (MW)	Project Count	Rebated Capacity (MW)	Project Count	Rebated Capacity (MW)	Project Count	Rebated Capacity (MW)	Project Count	Rebated Capacity (MW)	Project Count	Rebated Capacity (MW)	Project Count	Rebated Capacity (MW)	Project Count	Rebated Capacity (MW)
2002	17	2.0					1	0.2					6	4.0			2	0.2	1	0.1	27	6.4
2003	99	12.6											34	21.2	1	1.0	20	2.1	1	0.4	155	37.2
2004	161	16.3					1	0.6			1	1.4	51	35.2			21	3.0	4	0.9	239	57.4
2005	207	24.7			2	1.6	1	1.0	2	0.8	1	1.2	30	18.9	1	0.5	26	4.5	7	0.9	277	54.1
2006	155	25.5					7	4.0			2	9.0	54	31.1	8	5.2	24	4.2	3	0.8	253	79.7
2007	145	28.8					2	1.5			1	1.4	19	10.9	4	1.8	11	1.3	3	0.3	185	46.1
2008	96	22.7					3	1.2	3	2.7	1	4.6	17	10.7	3	2.8	9	3.0	2	0.4	134	48.1
2009	10	3.2			2	0.3	3	1.3	2	1.5	2	8.1	8	4.5	1	0.1	3	1.7			31	20.7
2010					4	2.8	5	1.3	7	2.9			8	2.7	4	2.7	2	0.3			30	12.6
2011					2	2.1	56	4.1	42	20.1			3	2.2	3	0.9	1	0.8			107	30.0
2012			2	1.6	4	3.6	43	14.4	17	12.7	1	4.4	1	0.3					1	0.8	69	37.8
Total	**890**	**135.8**	**2**	**1.6**	**14**	**10.3**	**122**	**29.5**	**73**	**40.6**	**9**	**30.1**	**231**	**141.6**	**25**	**14.8**	**119**	**21.0**	**22**	**4.5**	**1507**	**430.0**

Table A-7: Program Year Project Counts and Rebated Capacities by Technology (PY01 – PY11)[5]

Program Year	*PV*		*AES*		*Wind Turbines*		*Fuel Cells*		*Gas Turbines*		*IC Engines*		*Microturbines*		*Total*	
	Project Count	*Rebated Capacity (MW)*	*Project Count*	*Rebated Capacity (MW)*	*Project Count*	*Rebated Capacity (MW)*	*Project Count*	*Rebated Capacity (MW)*	*Project Count*	*Rebated Capacity (MW)*	*Project Count*	*Rebated Capacity (MW)*	*Project Count*	*Rebated Capacity (MW)*	*Project Count*	*Rebated Capacity (MW)*
PY01	21	3.5					1	0.2			27	14.7	21	2.8	70	21.2
PY02	117	14.9					1	0.6	1	1.4	54	36.5	17	2.9	190	56.3
PY03	161	18.0			2	1.6	2	0.8	1	1.2	54	37.5	40	5.0	260	64.1
PY04	298	40.6					3	2.3	1	1.4	49	24.6	30	5.7	381	74.5
PY05	64	13.5					6	3.7	2	9.0	31	22.4	14	3.1	117	51.6
PY06	229	45.4					7	5.1	3	12.7	17	11.2	13	4.1	269	78.6
PY07					2	1.2	3	1.2	1	4.4	24	9.6	6	1.9	36	18.3
PY08					1	0.2	7	0.6							8	0.9
PY09			1	1.0	3	1.6	26	10.0							30	12.6
PY10			1	0.6	5	5.6	136	44.8							142	51.0
PY11					1	0.1	3	0.9							4	1.0
Total	**890**	**135.8**	**2**	**1.6**	**14**	**10.3**	**195**	**70.1**	**9**	**30.1**	**256**	**156.5**	**141**	**25.5**	**1507**	**430.0**

[5] Project counts and rebated capacities use the check issued date for Complete projects when reported by calendar year. When reported by program year, project counts and rebated capacities are based on the application date of the Complete project.

Table A-8: Program Year Project Counts and Rebated Capacities by Technology and Fuel Type (PY01–PY11)

Program Year	PV		AES		Wind Turbine		Fuel Cells				Gas Turbines		IC Engines				Microturbines				Total	
	Solar		No Fuel		Wind		Natural Gas		Biogas		Natural Gas		Natural Gas		Biogas		Natural Gas		Biogas			
	Project Count	Rebated Capacity (MW)	Project Count	Rebated Capacity (MW)	Project Count	Rebated Capacity (MW)	Project Count	Rebated Capacity (MW)	Project Count	Rebated Capacity (MW)	Project Count	Rebated Capacity (MW)	Project Count	Rebated Capacity (MW)	Project Count	Rebated Capacity (MW)	Project Count	Rebated Capacity (MW)	Project Count	Rebated Capacity (MW)	Project Count	Rebated Capacity (MW)
PY01	21	3.5					1	0.2					26	13.7	1	1.0	18	2.2	3	0.6	70	21.2
PY02	117	14.9					1	0.6			1	1.4	54	36.5			15	2.2	2	0.7	190	56.3
PY03	161	18.0			2	1.6			2	0.8	1	1.2	52	36.7	2	0.8	34	4.0	6	1.0	260	64.1
PY04	298	40.6					3	2.3			1	1.4	46	23.0	3	1.6	25	5.2	5	0.5	381	74.5
PY05	64	13.5					6	3.7			2	9.0	26	17.9	5	4.5	11	2.4	3	0.7	117	51.6
PY06	229	45.4					3	1.5	4	3.6	3	12.7	11	7.8	6	3.4	11	3.9	2	0.3	269	78.6
PY07					2	1.2	3	1.2			1	4.4	16	5.9	8	3.6	5	1.2	1	0.8	36	18.3
PY08					1	0.2	6	0.0	1	0.6											8	0.9
PY09			1	1.0	3	1.6	16	2.8	10	7.2											30	12.6
PY10			1	0.6	5	5.6	81	16.9	55	28.0											142	51.0
PY11					1	0.1	2	0.4	1	0.5											4	1.0
Total	**890**	**135.8**	**2**	**1.6**	**14**	**10.3**	**122**	**29.5**	**73**	**40.6**	**9**	**30.1**	**231**	**141.6**	**25**	**14.8**	**119**	**21.0**	**22**	**4.5**	**1507**	**430.0**

Table A-9 shows the cumulative trend of all SGIP projects by technology including photovoltaics, which were discontinued from the program.

Table A-9: Detailed Cumulative Trends by Technology and Rebated Capacity for All Projects (MW)

Calendar Year	*Photo-voltaic*	*IC Engines*	*Fuel Cells*	*Gas Turbines*	*Micro-turbines*	*Wind Turbine*	*Advanced Energy Storage*	*Grand Total*
2002	2.0	4.0	0.2	-	0.3	-	-	6.4
2003	14.6	26.1	0.2	-	2.7	-	-	43.6
2004	30.9	61.3	0.8	1.4	6.6	-	-	101.0
2005	55.6	80.7	2.6	2.6	11.9	1.6	-	155.1
2006	81.1	117.0	6.5	11.6	16.9	1.6	-	234.8
2007	110.0	129.7	8.0	13.0	18.6	1.6	-	280.9
2008	132.7	143.1	11.9	17.6	22.0	1.6	-	329.0
2009	135.8	147.8	14.7	25.7	23.7	1.9	-	349.7
2010	135.8	153.1	18.9	25.7	24.0	4.7	-	362.3
2011	135.8	156.1	43.0	25.7	24.8	6.8	-	392.3
2012	135.8	156.5	70.1	30.1	25.5	10.3	1.6	430.0

Table A-10 summarizes the distribution of projects and rebated capacity by PA.

Table A-10: Complete Projects by Program Administrator

Program Administrator	*No. of Projects*	*Rebated Capacity (MW)*	*Percent of Total Rebated Capacity*
CCSE	61	33	11%
PG&E	291	117	40%
SCE	121	55	19%
SCG	144	89	30%
Total	**617**	**294**	**100%**

Table A-11 illustrates the overlap of municipal SGIP projects in PA territories. Municipal SGIP projects are found mostly in PG&E and SCG territories.

Table A-11: IOU and Municipal Projects Overlap

PA Territory by Municipal/IOU Overlap		*Rebated Capacity (MW)*						*Total*	
		IC Engine	*Fuel Cell*	*Micro-turbine*	*Wind*	*Gas Turbine*	*Advanced Energy Storage*	*Total Rebated Capacity (MW)*	*Percent of Total Rebated Capacity*
PG&E	**IOU**	62	32	11	3	4	N/A	112	38%
	Municipal	0	0	N/A	4	N/A	1	5	2%
SCG	**IOU**	50	5	5	N/A	17	1	77	26%
	Municipal	3	7	2	N/A	N/A	N/A	12	4%
SCE	**IOU**	31	14	6	4	N/A	N/A	55	19%
	Municipal	N/A	0	N/A	N/A	N/A	N/A	0	0%
CCSE	**IOU**	11	11	2	N/A	9	N/A	33	11%
	Municipal	N/A	0	N/A	N/A	N/A	N/A	0	0%
Total		**156**	**70**	**26**	**10**	**30**	**2**	**294**	**100%**

Incentives Paid and Project Costs

Table A-12 shows incentives paid through 2012 by technology. A total of $404 million dollars have been paid for 294 megawatts of rebated capacity.

Table A-12: Incentives Paid By Rebated Capacity and Technology Type (2012)

Technology	*Incentives Paid*	
	Rebated Capacity (MW)	*Total ($MM)*
Fuel Cell	70	$266
IC Engine	156	$94
Microturbine	26	$22
Wind Turbine	10	$13
Gas Turbine	30	$6
Advanced Energy Storage	2	$3
TOTAL	**294**	**$404**

Table A-13 shows the contribution SGIP project participants have made cumulatively for the incentives received by technology. Participants have spent $800 million on SGIP projects; and overall projects costs have exceeded $1.2billion.

Table A-13: Participant Cost Paid By Rebated Capacity and Technology

Technology	*Paid*		
	Total (MW)	***Weighted Average ($/W)***	***Total ($MM)***
Fuel Cell	70	$5.34	$374
IC Engine	156	$1.78	$279
Microturbine	26	$2.44	$62
Gas Turbine	30	$1.78	$54
Wind Turbine	10	$2.24	$23
Advanced Energy Storage	2	$5.29	$8
Overall	**294**	**$2.72**	**$800**

Table A-14 shows the progressive annual project costs, Incentives Paid and leverage ratio by technology. The leverage ratio is a measure of the participant cost relative to the incentive paid. Overall, SGIP incentive payments have been approximately one-third of project costs. Table A-15 provides the same data but by program year and reflects the changes in program requirements over time. Table A-16 refines the program year data further by both technology and fuel type.

Table A-14: Annual Cumulative System Cost, Incentive and Leverage Ratio Trends by Technology Type

Technology		*Calendar Year (Millions of Dollars)*											
		2002	*2003*	*2004*	*2005*	*2006*	*2007*	*2008*	*2009*	*2010*	*2011*	*2012*	*CUMULATIVE*
Fuel Cells CHP	**Eligible Costs**	3.60	-	4.26	14.43	26.48	10.57	25.11	17.71	11.67	21.14	42.50	177.47
	Incentives	0.50	-	1.50	5.83	8.76	3.50	14.66	8.25	3.90	6.63	18.91	72.44
	Leverage Ratio	6.20	N/A	1.84	1.47	2.02	2.02	0.71	1.15	1.99	2.19	1.25	1.45
IC Engines	**Eligible Costs**	7.31	45.34	77.58	42.86	88.53	31.17	36.53	11.84	20.20	9.60	1.40	372.36
	Incentives	2.13	12.60	20.28	11.81	22.97	7.51	8.29	2.19	3.57	2.26	0.20	93.81
	Leverage Ratio	2.43	2.60	2.82	2.63	2.85	3.15	3.41	4.42	4.67	3.24	5.94	2.97
Gas Turbines	**Eligible Costs**	-	-	3.73	4.69	13.30	7.18	8.35	21.22	-	-	1.38	59.86
	Incentives	-	-	0.81	1.00	1.05	1.00	0.60	1.20	-	-	0.60	6.26
	Leverage Ratio	N/A	N/A	3.61	3.69	11.64	6.18	12.92	16.68	N/A	N/A	1.30	8.56
Microturbines	**Eligible Costs**	0.70	6.14	11.55	19.08	15.00	7.45	12.24	5.45	2.44	2.22	2.42	84.69
	Incentives	0.18	1.86	3.24	5.14	4.55	1.50	2.97	1.17	0.25	0.60	0.98	22.45
	Leverage Ratio	2.89	2.30	2.56	2.71	2.30	3.96	3.12	3.65	8.66	2.70	1.48	2.77
Wind Turbine	**Eligible Costs**	-	-	-	5.38	-	-	-	1.50	10.34	5.39	13.29	35.90
	Incentives	-	-	-	2.63	-	-	-	0.43	4.07	-	5.64	12.77
	Leverage Ratio	N/A	N/A	N/A	1.04	N/A	N/A	N/A	2.50	1.54	N/A	1.36	1.81
Fuel Cells Electric Only	**Eligible Costs**	-	-	-	-	-	-	-	6.73	30.93	209.74	215.12	462.52
	Incentives	-	-	-	-	-	-	-	1.90	13.12	99.04	79.05	193.11
	Leverage Ratio	N/A	N/A	N/A	N/A	N/A	N/A	N/A	2.54	1.36	1.12	1.72	1.40
Advanced Energy Storage	**Eligible Costs**	-	-	-	-	-	-	-	-	-	-	11.66	11.66
	Incentives	-	-	-	-	-	-	-	-	-	-	3.20	3.20
	Leverage Ratio	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	2.64	2.64
Overall	**Eligible Costs**	11.62	51.48	97.13	86.43	143.32	56.37	82.24	64.44	75.58	248.09	287.76	1,204.46
	Incentives	2.81	14.46	25.84	26.42	37.33	13.51	26.52	15.13	24.92	108.53	108.57	404.05
	Leverage Ratio	3.13	2.56	2.76	2.27	2.84	3.17	2.10	3.26	2.03	1.29	1.65	1.98

Table A-15: Program Year Cumulative System Cost, Incentive and Leverage Ratio Trends by Technology Type

Technology		Program Year (Millions of Dollars)											
		PY01	PY02	PY03	PY04	PY05	PY06	PY07	PY08	PY09	PY10	PY11	CUMULATIVE
Fuel Cells CHP	Eligible Costs	3.60	4.26	7.28	16.97	22.46	37.43	4.47	6.03	24.44	46.56	3.98	177.47
	Incentive	0.50	1.50	3.38	5.58	7.89	19.46	2.00	2.79	7.74	20.70	0.91	72.44
	Leverage Ratio	6.20	1.84	1.16	2.04	1.85	0.92	1.24	1.16	2.16	1.25	3.36	1.45
IC Engines	Eligible Costs	30.71	81.12	81.33	61.53	53.58	29.78	34.30	-	-	-	-	372.36
	Incentive	9.04	20.67	21.54	16.86	12.13	6.96	6.61	-	-	-	-	93.81
	Leverage Ratio	2.40	2.92	2.78	2.65	3.42	3.28	4.19	N/A	N/A	N/A	N/A	2.97
Gas Turbines	Eligible Costs	-	3.73	4.69	7.18	13.30	29.57	1.38	-	-	-	-	59.86
	Incentive	-	0.81	1.00	1.00	1.05	1.80	0.60	-	-	-	-	6.26
	Leverage Ratio	N/A	3.61	3.69	6.18	11.64	15.43	1.30	N/A	N/A	N/A	N/A	8.56
Microturbines	Eligible Costs	8.14	8.41	17.41	17.50	11.62	14.08	7.53	-	-	-	-	84.69
	Incentive	2.22	2.33	4.78	5.07	2.85	3.28	1.92	-	-	-	-	22.45
	Leverage Ratio	2.67	2.61	2.64	2.45	3.08	3.29	2.91	N/A	N/A	N/A	N/A	2.77
Wind Turbine	Eligible Costs	-	-	5.38	-	-	-	6.35	0.35	5.14	18.30	0.38	35.90
	Incentive	-	-	2.63	-	-	-	1.84	0.26	2.41	5.55	0.09	12.77
	Leverage Ratio	N/A	N/A	1.04	N/A	N/A	N/A	2.46	0.34	1.14	2.30	3.33	1.81
Fuel Cells Electric Only	Eligible Costs	-	-	-	-	-	-	3.85	-	68.56	384.91	5.20	462.52
	Incentive	-	-	-	-	-	-	1.00	-	27.30	162.31	2.50	193.11
	Leverage Ratio	N/A	N/A	N/A	N/A	N/A	N/A	2.85	N/A	1.51	1.37	1.08	1.40
Advanced Energy Storage	Eligible Costs	-	-	-	-	-	-	-	-	6.49	5.17	-	11.66
	Incentive	-	-	-	-	-	-	-	-	2.00	1.20	-	3.20
	Leverage Ratio	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	2.25	3.30	N/A	2.64
Overall	Eligible Costs	42.45	97.53	116.09	103.19	100.96	110.86	57.88	6.38	104.63	454.93	9.56	1,204.46
	Incentive	11.76	25.31	33.33	28.51	23.92	31.50	13.97	3.05	39.45	189.76	3.50	404.05
	Leverage Ratio	2.61	2.85	2.48	2.62	3.22	2.52	3.14	1.09	1.65	1.40	1.73	1.98

Table A-16: Program Year Cumulative System Cost, Incentive and Leverage Ratio Trends by Technology Type and Fuel

Technology and Fuel Type			*Program Year (Millions of Dollars)*											
			PY01	*PY02*	*PY03*	*PY04*	*PY05*	*PY06*	*PY07*	*PY08*	*PY09*	*PY10*	*PY11*	*CUMULATIVE*
Fuel Cells	**Non-Renewable**	**Eligible Costs**	$3.60	$4.26	-	$16.97	$22.46	$15.34	$8.32	$0.34	$22.52	$162.84	$3.98	$260.63
		Incentive	$0.50	$1.50	-	$5.58	$7.89	$3.71	$3.00	$0.09	$6.46	$49.30	$0.91	$78.94
		Leverage Ratio	6.20	1.84	N/A	2.04	1.85	3.13	1.77	2.92	2.49	2.30	3.36	2.30
	Renewable (Biogas)	**Eligible Costs**	-	-	$7.28	-	-	$22.09	-	$5.69	$70.48	$268.62	$5.20	$379.36
		Incentive	-	-	$3.38	-	-	$15.75	-	$2.70	$28.58	$133.72	$2.50	$186.62
		Leverage Ratio	N/A	N/A	1.16	N/A	N/A	0.40	N/A	1.11	1.47	1.01	1.08	1.03
IC Engines	**Non-Renewable**	**Eligible Costs**	$28.71	$81.12	$79.21	$59.00	$42.12	$20.31	$19.35	-	-	-	-	$329.82
		Incentive	$8.34	$20.67	$20.75	$15.99	$7.79	$3.93	$3.55	-	-	-	-	$81.03
		Leverage Ratio	2.44	2.92	2.82	2.69	4.41	4.17	4.45	N/A	N/A	N/A	N/A	3.07
	Renewable (Biogas)	**Eligible Costs**	$2.00	-	$2.13	$2.53	$11.46	$9.47	$14.95	-	-	-	-	$42.54
		Incentive	$0.70	-	0.79	0.86	4.34	3.03	3.06	-	-	-	-	$12.78
		Leverage Ratio	1.86	N/A	1.71	1.93	1.64	2.13	3.89	N/A	N/A	N/A	N/A	2.33
Micro-turbines	**Non-Renewable**	**Eligible Costs**	$6.53	$6.83	$13.59	$15.37	$8.61	$13.19	$5.11	-	-	-	-	$69.24
		Incentive	$1.73	$1.70	$3.51	$4.41	$1.90	$2.92	$0.95	-	-	-	-	$17.12
		Leverage Ratio	2.77	3.03	2.87	2.49	3.53	3.52	4.39	N/A	N/A	N/A	N/A	3.05
	Renewable (Biogas)	**Eligible Costs**	$1.61	$1.58	$3.83	$2.13	$3.00	$0.89	$2.42	$-	$-	$-	$-	$15.45
		Incentive	$0.48	$0.63	$1.27	$0.66	$0.95	$0.36	$0.98	$-	$-	$-	$-	$5.34
		Leverage Ratio	2.33	1.50	2.02	2.21	2.17	1.44	1.48	N/A	N/A	N/A	N/A	1.90
Gas Turbines	**Non-Renewable**	**Eligible Costs**	-	$3.73	$4.69	$7.18	$13.30	$29.57	$1.38	-	-	-	-	$59.86
		Incentive	-	$0.81	1.00	$1.00	$1.05	$1.80	$0.60	-	-	-	-	$6.26
		Leverage Ratio	N/A	3.61	3.69	6.18	11.64	15.43	1.30	N/A	N/A	N/A	N/A	8.56
Wind Turbine	**No Fuel**	**Eligible Costs**	-	-	$5.38	-	-	-	$6.35	$0.35	$5.14	$18.30	0.38	$35.90
		Incentive	-	-	$2.63	-	-	-	$1.84	$0.26	$2.41	$5.55	0.09	$12.77
		Leverage Ratio	N/A	N/A	1.04	N/A	N/A	N/A	2.46	0.34	1.14	2.30	3.33	1.81

Technology and Fuel Type			Program Year (Millions of Dollars)											
			PY01	PY02	PY03	PY04	PY05	PY06	PY07	PY08	PY09	PY10	PY11	CUMULATIVE
Advanced Energy Storage	**No Fuel**	**Eligible Costs**	-	-	-	-	-	-	-	-	$6.49	$5.17	-	$11.66
		Incentive	-	-	-	-	-	-	-	-	$2.00	$1.20	-	$3.20
		Leverage Ratio	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	2.25	3.30	N/A	2.64
Overall	**Non-Renewable**	**Eligible Costs**	$38.84	$95.95	$97.48	$98.53	$86.50	$78.41	$34.16	$0.34	$22.52	$162.84	$3.98	$719.55
		Incentive	$10.57	$24.68	$25.27	$26.98	$18.64	$12.36	$8.10	$0.09	$6.46	$49.30	$0.91	$183.35
		Leverage Ratio	2.67	2.89	2.86	2.65	3.64	5.35	3.22	2.92	2.49	2.30	3.36	2.92
	Renewable (Biogas)	**Eligible Costs**	$3.61	$1.58	$13.23	$4.66	$14.46	$32.45	$17.37	$5.69	$70.48	$268.62	$5.20	$437.35
		Incentive	$1.18	$0.63	$5.43	$1.53	$5.29	$19.14	$4.03	$2.70	$28.58	$133.72	$2.50	$204.73
		Leverage Ratio	2.05	1.50	1.44	2.05	1.73	0.69	3.30	1.11	1.47	1.01	1.08	1.14
	No Fuel	**Eligible Costs**	-	-	$5.38	-	$-	-	$6.35	$0.35	$11.63	$23.47	$0.38	$47.55
		Incentive	-	-	$2.63	-	$-	-	$1.84	$0.26	$4.41	$6.75	$0.09	$15.97
		Leverage Ratio	N/A	N/A	2.04	N/A	N/A	N/A	2.46	0.34	1.64	2.48	3.33	1.98

Appendix B

APPENDIX B
ENERGY AND DEMAND IMPACTS AND ESTIMATION METHODOLOGY

B.1 Overview

In this appendix we provide discrete values of electric energy and demand impact estimates. We also describe availability and sources of metered impact data and the analytic methodology used to develop impact estimates where metered data are not available. All impact values in this appendix are estimates inasmuch as all values represent sums of metered and estimated impacts.

Electric energy impacts are the cumulative generation, net of parasitic loads[1], from SGIP systems over a specific time interval. We describe energy impacts in units of kWh, MWh or GWh.

Demand impacts are the average power generation, net of parasitic loads, from SGIP systems over a specific hour or set of hours. We describe demand impacts in units of MW or GW.

To permit direct comparisons between different capacities we also describe energy and demand impacts in relative units of capacity factors. Capacity factor is a function of system output relative to system nameplate capacity. Capacity factor indicates the fraction of energy actually generated during a period relative to what could have been if the system operated at its full nameplate capacity.

We include impact values here only from SGIP Fuel Cells (FC), Gas Turbines (GT), Internal Combustion Engines (ICE), and Microturbines (MT). We distinguish natural gas fuel as non-renewable (N) and biogas fuel as renewable (R). Renewable fuel includes landfill and digester gas and other biogas, both onsite and directed into natural gas pipelines. Non-renewable fuel includes natural gas and very small amount of propane.

Impacts from wind, alternative energy storage, and photovoltaic SGIP systems are <u>not</u> reflected in these values.

The appendix includes these sections:

B.2 Energy Impacts: summaries by technology, fuel, and Program Advisor (PA)

B.3 Demand Impacts: summaries by technology, fuel, and investor owned utility (IOU)

B.4 Estimation Methodology: description of metered impact data availability and analysis to develop estimated impacts

B.2 Energy Impacts

Table B-1 lists 2012 end of year system counts, capacity sums, annual energy impacts, and capacity weighted annual capacity factors by technology type and fuel.

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[1] For example, loads of compressor, fan, or pump, motors that serve system operation.

Table B-1: 2012 Energy Impacts by Technology Type and Fuel

Technology	*Fuel*	*System Count at Year's End*	*Capacity (MW) at Year's End*	*Annual Energy Impact (GWh)*	*Annual Weighted Capacity Factor*
FC	N	122	29.5	151	0.67
FC	R	73	40.6	225	0.72
GT	N	9	30.1	220	0.83
ICE	N	231	141.6	244	0.20
ICE	R	25	14.8	57	0.44
MT	N	119	21.0	69	0.37
MT	R	22	4.5	4	0.11
Total		**601**	**282**	**970**	

Figure B-1 shows annual energy impacts from 2002 through 2012 with contributions by technology and fuel type distinguished by color.

Figure B-1: Annual Electric Energy Impacts, 2002 through 2012

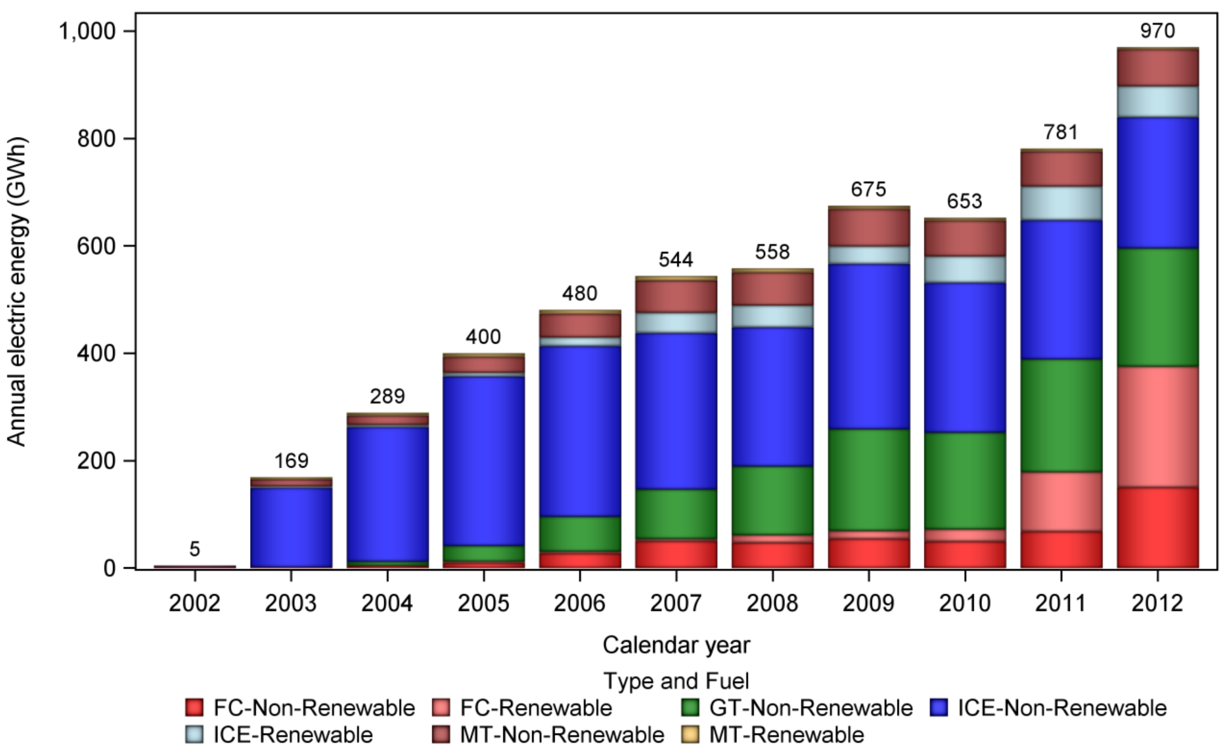

Table B-2 lists 2012 end of year system counts, capacity sums, annual energy impacts, and capacity weighted annual capacity factors by PA, technology type, and fuel.

Table B-2: 2012 Energy Impacts by PA, Technology Type, and Fuel

PA	*Technology*	*Fuel*	*System Count at Year's End*	*Capacity (MW) at Year's End*	*Annual Energy Impact (GWh)*	*Annual Weighted Capacity Factor*
CCSE	FC	N	11	4.1	11.8	0.43
CCSE	FC	R	10	7.1	45.8	0.79
CCSE	GT	N	2	9.1	78.7	0.98
CCSE	ICE	N	20	10.6	7.1	0.08
CCSE	ICE	R	1	0.6	4.5	0.91
CCSE	MT	N	13	1.1	1.2	0.12
CCSE	MT	R	4	0.8	0.7	0.10
CCSE	**Total**		**61**	**33.4**	**149.8**	
PGE	FC	N	76	18.2	103	0.72
PGE	FC	R	33	14.0	91.3	0.82
PGE	GT	N	3	4.0	18	0.51
PGE	ICE	N	100	55.1	115.4	0.24
PGE	ICE	R	13	6.9	26.8	0.44
PGE	MT	N	43	9.2	39.8	0.49
PGE	MT	R	13	2.0	3.2	0.19
PGE	**Total**		**281**	**109.3**	**397.5**	
SCE	FC	N	11	3.7	22.1	0.79
SCE	FC	R	19	10.4	52	0.65
SCE	ICE	N	48	26.1	31.5	0.14
SCE	ICE	R	7	4.8	13.7	0.33
SCE	MT	N	26	4.3	9.9	0.26
SCE	MT	R	5	1.8	0.2	0.02
SCE	**Total**		**116**	**51.1**	**129.4**	
SCG	FC	N	24	3.6	13.7	0.54
SCG	FC	R	11	9.2	36	0.57
SCG	GT	N	4	17.0	123.6	0.83
SCG	ICE	N	63	49.8	89.9	0.21
SCG	ICE	R	4	2.6	12.5	0.55
SCG	MT	N	37	6.3	17.6	0.32
SCG	**Total**		**143**	**88.5**	**293.3**	

B.3 Demand Impacts

Table B-3 lists 2012 CAISO peak hour demand impacts and capacity-weighted average hourly capacity factors by technology and fuel type. It also lists totals and unweighted average capacity factors by fuel and for the program as a whole. Capacity factors reflect capacity of all corresponding systems including any known to be decommissioned. The table also lists system counts and capacity totals during the CAISO peak hour. System counts and capacities may be less than end of year values because new systems may be added after the CAISO peak hour.

Table B-3: 2012 CAISO Peak Hour Demand Impacts by Technology Type

Technology	*Fuel*	*System Count*	*Capacity (MW)*	*Demand Impact (MW)*	*Capacity Factor*
FC	N	116	27.2	19.4	0.71
FC	R	71	36.4	23.3	0.64
GT	N	9	30.1	28.9	0.96
ICE	N	231	141.6	42.8	0.30
ICE	R	25	14.8	6.2	0.42
MT	N	119	21.0	7.1	0.34
MT	R	22	4.5	0.3	0.06
Total	N	475	220.0	98.2	0.45
Total	R	118	55.8	29.8	0.53
Total		**593**	**276**	**128**	**0.46**

Table B-4 lists 2012 IOU peak hour demand impacts and weighted average hourly capacity factors by technology and fuel type. Systems not connected to one of the IOUs are not included in this table. Capacity factors reflect capacity of all corresponding systems including any known to be decommissioned. System counts and capacity totals during peak hours may be less than end of year values because new systems may be added after the IOU peak hours.

Table B-4: 2012 IOU Peak Hour Impacts by Technology Type

IOU	*Technology*	*Fuel*	*System Count*	*Capacity (MW)*	*Demand Impact (MW)*	*Capacity Factor*
PGE	FC	N	47	17.5	13.7	0.78
PGE	FC	R	32	12.6	9.6	0.76
PGE	GT	N	3	4	3.6	0.9
PGE	ICE	N	104	57.4	20.2	0.35
PGE	ICE	R	15	8.1	4.1	0.51
PGE	MT	N	46	9.4	4	0.42
PGE	MT	R	13	2	0.2	0.08
PGE	**Total**		**260**	**111**	**55.4**	
SCE	FC	N	24	4.7	3.3	0.71
SCE	FC	R	21	11.9	7.1	0.59
SCE	GT	N	4	17	15.4	0.9

IOU	Technology	Fuel	System Count	Capacity (MW)	Demand Impact (MW)	Capacity Factor
SCE	ICE	N	99	69.1	19.7	0.29
SCE	ICE	R	9	6.2	1.6	0.26
SCE	MT	N	52	8.9	2.7	0.3
SCE	MT	R	5	1.8	0	0.02
SCE	**Total**		**214**	**119.6**	**49.8**	
SDGE	FC	N	9	3	0.9	0.31
SDGE	FC	R	10	7.1	3.9	0.55
SDGE	GT	N	2	9.1	10	1.1
SDGE	ICE	N	21	12.1	1.6	0.13
SDGE	ICE	R	1	0.6	0	0
SDGE	MT	N	13	1.1	0.2	0.18
SDGE	MT	R	4	0.8	0	0.06
SDGE	**Total**		**60**	**33.8**	**16.6**	

B.4 Estimation Methodology

We develop impact values for every individual SGIP system-hour of operation. We use directly metered impacts for a majority of these values. Where metered values are not available, we develop estimated impact values using directly metered impacts under the methodology described here.

We base all estimated system-hour impact values on metered impacts from similar systems during the very same or similar hours. Similar systems are those with these four system features matching:

1. technology type
2. fuel type
3. program advisor
4. operating status[2]

We develop a small percentage of estimated system-hour impacts from metered impacts where these four system features do not all match or where the hours are not identical. These few impact estimates arise where fewer than five system-hour metered impacts exist for similar systems in the very same hour.[3] For this small percentage of impact estimates the scope of matching system features or matching hours is relaxed. The relaxation begins with allowance for inclusion of systems with different Program Advisors (PA). If still fewer than five system-hours have metered impacts during the very same hour, the relaxation continues by allowing systems with different fuel type. If still fewer than five system-hours have metered impacts during the very same hour, the four matching system features are enforced again

[2] Operating status is either on-line or offline during a calendar month. Systems on-line have metered generation greater than a minimum or have been described as on-line by a representative of the Host.

[3] We consider five matching system-hours the minimum number to avoid potential bias and to maintain robust estimates.

but additional hours are allowed. The additional hours are the same hours of the same day of week in the same calendar month. This last relaxation is the least-often used.

The estimation methodology that applies to energy impacts is the same that applies to demand impacts because the results are interchangeable. In individual hours the numeric value of energy impact in MWh is the numeric value of hourly average power in MW.

Estimation of Energy When Metered Values Unavailable

Every hour for every system has an associated kWh value. If the kWh were not metered directly, they are estimated using a ratio estimator and the unmetered system's nominal generating capacity. The ratio estimator is an average energy output per unit of capacity from no fewer than five metered observations from among like systems during the same or similar hours.

For some unmetered systems a phone survey provided qualitative operating status information for the most recent calendar year. This information classified system operating status by system-month as either online or offline. For off-line months impacts are estimated using a ratio estimator of zero. For on-line months impacts are estimated using ratio estimators developed only from metered systems identified as being on-line in the month. A metered system-month is classified as on-line if no more than 30 percent of data are missing and the monthly capacity factor is greater than 0.01. Ratio estimators developed only from on-line system-months do not include metered data from systems that were offline or from systems known to be temporarily or permanently retired, i.e., data that would include only impact values of zero.

For some unmetered systems no operating status information was available. Ratio estimators developed to estimate their impacts are based on all metered data regardless of whether metered system-months are on-line or offline. Ratio estimators developed by this approach included metered data from systems that are offline and from systems known to be temporarily or permanently retired, i.e., data that would include only impact values of zero.

Estimates of hourly impact are calculated as the product of a system's nominal generating capacity and a ratio estimator. As shown below the ratio estimator is a sum of metered net generator outputs divided by a sum of nominal generating capacities.

$$EN\hat{G}O_{psdh} = \left(S_{ps}\right)_{Unmetered} \times \left(\frac{\sum ENGO_{psdh}}{\sum S_{ps}}\right)_{Metered}$$

Where:

$\hat{ENGO}_{psdh}$ = Predicted net generator output for system *p* in strata[4] *s* on date *d* during hour *h*

Units: kWh

Source: calculated

[4] Strata are always defined by similar time and system parameters. As described in text, however, time and system parameter similarity of some strata are less exacting to be certain a minimum number of metered observations contribute to ratio estimator.

S_{ps} = Nominal generating capacity for system *p* in strata *s*

Units: kW

Source: SGIP Tracking Database

$ENGO_{psdh}$ = Metered net generator output for system *p* in strata *s* on date *d* during hour *h*

Units: kWh

Source: meters recording net generator output

Key Data Types

There are four key data types that contribute to the determination of energy and demand impacts:

1. System lists maintained by the Program Administrators (PAs),
2. Reports from monitoring planning and installation verification site visits,
3. Metered data received from system Hosts, Applicants, third-party metering, or metering installed by Itron, and
4. Phone survey data on operating status of unmetered systems.

System Lists Maintained by Program Administrators

SGIP PAs maintain a state-wide tracking database containing information essential for designing and conducting SGIP impact evaluation activities. The PAs provide Itron with access to the statewide database for purposes of downloading system tracking data necessary to plan and implement program impacts evaluation activities. Information of particular importance includes basic system characteristics (e.g., technology type, system rebated capacity, fuel type) and key participant characteristics (e.g., Host and Applicant names[5], addresses, and phone numbers). The system's technology type, program year, and location (by PA area) are used in developing a sample design to ensure collection of data necessary to develop statistically significant estimates of program impacts. Updated SGIP Handbooks are used for planning and reference purposes.[6]

Reports from Monitoring Planning and Installation Verification Site Visits

Information obtained from the PA system database is augmented and updated through inspection visits to the SGIP system sites conducted by independent consultants hired by the PAs to perform verification

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[5] The Host is the customer of record at the site where the generating equipment is or will be located. An Applicant is a person or entity who applies to the PA for incentive funding. Third parties (e.g., a party other than the PA or the utility customer) such as engineering firms, installing contractors, equipment distributors or Energy Service Companies (ESCO) are also eligible to apply for incentives on behalf of the utility customer, provided consent is granted in writing by the customer.

[6] SGIP Handbooks are available on PA websites.

of SGIP installations. System-specific information is reported in Inspection Reports produced by these independent consultants. The PAs regularly provide copies of the Inspection Reports to Itron. In addition, Itron engineers conduct site visits in preparing monitoring plans for on-site data collection activities from some systems. The types of information collected during these site inspections or in preparation of monitoring plans include meter numbers, nominal nameplate rating, and the date the system entered normal operation.

Metered Performance Data

In addition to information collected from the PA system database and from site visits, metered data are also used where they are available. The metered data used for evaluation purposes include electric net generator output (ENGO) data, useful thermal energy (HEAT) data, and fuel use (FUEL) data.

Operating Status Data

Using a short phone survey we collect operating status data on systems for which no metered data are available and that are not known to be permanently retired. Completed surveys allow classification of system-months as offline or online. For offline system-months we estimate impacts using ratio estimators equal to zero. For on-line system months we estimate impacts using ratio estimators developed from similar systems whose metered data indicate they were online that month. Some surveys determine a system to be permanently retired. A best estimate of a decommissioning date is developed from the survey. We estimate impacts using ratio estimators equal to zero for all system-hour impacts from that date forward.

The operating status survey targets most recently identified 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 are out of date contact information may be sought from internet sources. Operating status surveys are conducted only with contacts familiar with the operational status of the unmetered system.

Electric Net Generator Output (ENGO) Data

Metered ENGO data provide information on the amount of electricity generated by the SGIP system. These data (recorded typically at 15-minute intervals, but sometimes at hourly or larger intervals) determine energy and demand impacts from SGIP systems.

ENGO data are collected from a variety of sources, including meters Itron installed on SGIP systems under the direction of the PAs and meters installed by system Hosts, Applicants, electric utilities, and third parties. Because many different meters are in use among the many different providers, these ENGO data arrive in a wide array of data formats. Some formats require elaborate processing to be put into a format common to all systems. During processing to the common format all gathered ENGO data pass through a quality control review. Only data that pass the review are accepted for use in the evaluation.

Useful Thermal Energy (HEAT) Data

Useful thermal energy is that energy captured by heat recovery equipment and used to satisfy heating and/or cooling loads at the SGIP system site. Useful thermal energy (also referred to as HEAT) data are used to assess compliance of SGIP cogeneration facilities with required levels of efficiency and useful waste heat recovery. In addition, useful thermal energy data for SGIP facilities enable estimation of baseline electricity and natural gas use that would otherwise have been provided by the utility companies. This information is used to assess energy efficiency impacts as well as to calculate GHG emission impact-estimates. HEAT data are collected from metering systems installed by Itron as well as metering systems installed by Applicants, Hosts, or third parties.

Over the course of the SGIP, the approach for collecting HEAT data has changed. HEAT data collection historically has involved installation of invasive monitoring equipment (i.e., insertion-type flow meters and temperature sensors). Many third parties or Hosts had this type of HEAT metering equipment installed at the time the SGIP system 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 is able to obtain the relevant data being collected by these Hosts and third parties. Itron initially adopts an approach to obtain HEAT data metered by others in an effort to minimize both the cost- and disruption-related aspects of installing HEAT monitoring equipment. The majority of useful thermal energy data for 2003 to 2004 were obtained in this manner.

Itron began installing HEAT meter systems in the summer of 2003 for SGIP systems that were included in the sample design but for which data from existing HEAT metering were not available. As the HEAT data collection effort grew, it became clear that Itron could no longer rely on data from third-party or Host customer metering. In numerous instances agreements and plans concerning these data did not translate into validated data records available for analysis. Uninterrupted collection and validation of reliable metered performance data was labor-intensive and required examination of the collected data by more expert staff, thereby increasing costs. In addition, reliance on HEAT data collected by SGIP Host customers and third parties created evaluation schedule impacts and other risks that more than outweighed the benefits of lower metering installation costs.

In mid-2006, Itron responded to the HEAT data issues by changing the approach to collection of HEAT data. Itron continued to collect HEAT data from others in those instances where the data could be obtained easily and reliably. In all other instances, an approach has been adopted of installing HEAT metering systems for those systems in the sample design. Itron adopted the installation of non-invasive metering equipment such as ultrasonic flow meters, clamp-on temperature sensors, and wireless, cellular-based communications to reduce the time and invasiveness of the installations and increase data communication reliability. The increase in equipment costs was offset by the decrease in installation time and a decrease in maintenance problems. This non-invasive approach has been used to obtain HEAT data throughout 2011.

Fuel Usage (FUEL) Data

Fuel usage (also called FUEL) data are used in the impact evaluation to determine overall system efficiencies of SGIP cogeneration facilities, to determine compliance of renewable fuel use facilities with renewable fuel use requirements, and to estimate GHG emission impacts. To date, fuel use data collection activities have focused exclusively on consumption of natural gas by SGIP systems. In the future it may also be necessary to monitor consumption of gaseous renewable fuel (i.e., biogas) to more accurately assess compliance of SGIP systems using blends of renewable and non-renewable fuels with renewable fuel use requirements.

FUEL data used in the impact evaluation are obtained mostly from FUEL metering systems installed on SGIP systems by natural gas utilities, SGIP participants, or by third parties. Itron reviews FUEL data obtained from others and documents their bases prior to processing the FUEL data into a common data format. Quality control reviews of FUEL data include merging fuel usage and ENGO data to check for reasonableness of gross electrical conversion efficiency. In cases where validity checks fail, data providers are contacted to further refine the basis of data. In some cases it is determined that data received are for a site-level meter rather than from metering dedicated to the SGIP system. These site-level data are excluded from the impact analysis.

Most gathered FUEL data are reported in intervals much greater than one hour (e.g., in daily or monthly intervals). In most instances we estimate hourly FUEL consumption based on the associated ENGO data. While these data enable calculation of monthly and annual operating efficiencies they do not provide information about system efficiency during periods of peak demand. To address this issue Itron has recommended to the PAs installation of pulse recorders on a subset of existing gas meters to enable collection of hourly FUEL data.

Appendix C

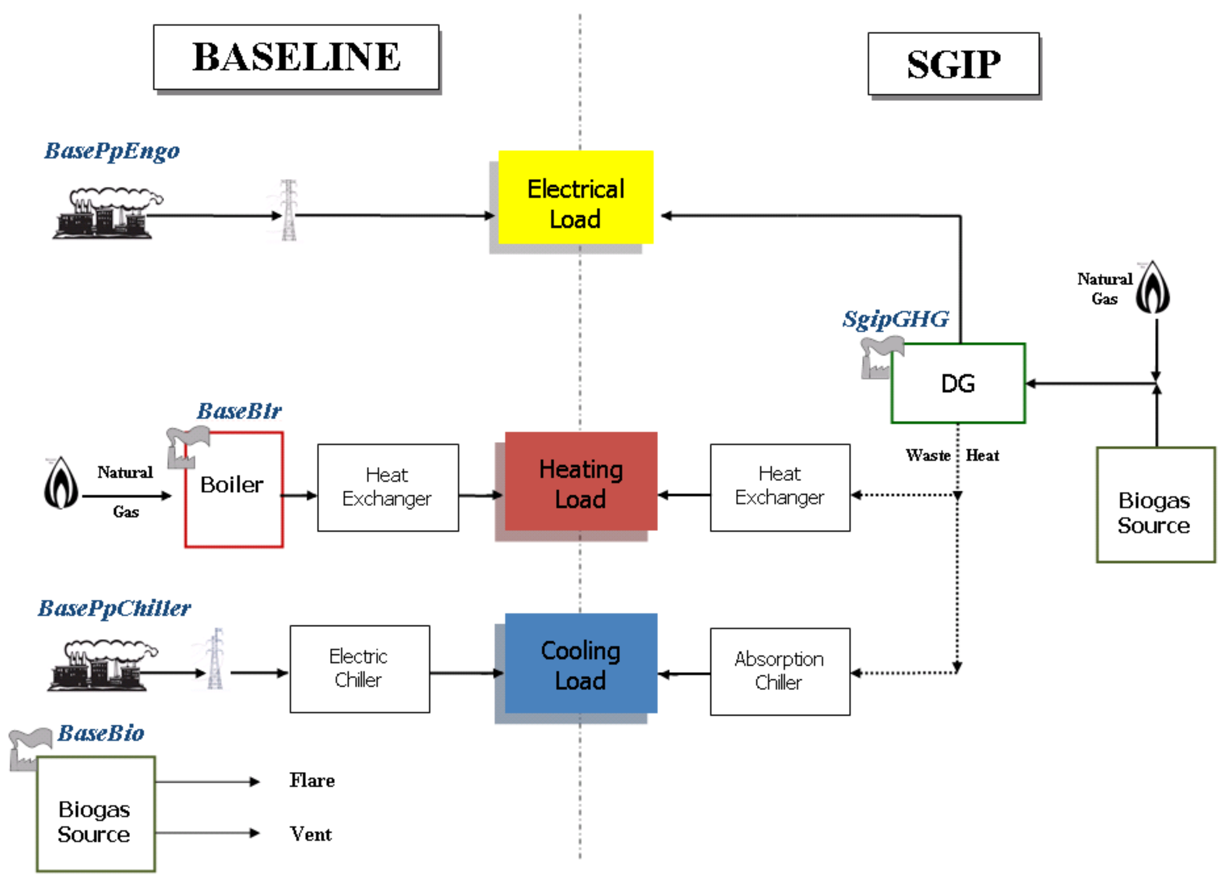
APPENDIX C
GREENHOUSE GAS IMPACTS METHODOLOGY

This appendix describes the methodology used to estimate the impacts on greenhouse gas (GHG) emissions from the operation of Self-Generation Incentive Program (SGIP) systems. 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 systems.

C.1 Overview

Hourly GHG impacts are calculated for each SGIP site as the difference between the GHG emissions produced by the rebated distributed generation (DG) system and baseline GHG emissions. Baseline GHG emissions are those that would have occurred in the absence of the SGIP system. SGIP systems displace baseline GHG emissions by satisfying site electric loads as well as heating/cooling loads, in some cases. SGIP systems 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 system. Each component of the GHG impacts calculations is shown in Figure C-1 and described below along with the variable name used in equations presented later.

Figure C-1: GHG Impacts Summary Schematic



SGIP System CO_2 Emissions (SgipGHG): The operation of renewable- and non-renewable-fueled DG systems (excluding wind) emits CO_2 as a result of combustion/conversion of the fuel powering the system. Hour-by-hour emissions of CO_2 from SGIP systems 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 technologies 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 systems 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 and 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 systems 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.

CO_2 Emissions Associated with Heating Services (BaseBlr): Waste heat is recovered from the operation of cogeneration systems. The recovered 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 systems 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 completion as SGIP prime movers.

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[1] In this analysis, GHG emissions from SGIP facilities 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 facilities have no impact on electricity generated from utility facilities not subject to economic dispatch. Consequently, comparison of SGIP facilities to nuclear or hydroelectric facilities is not made as neither of these technologies is subject to dispatch.

[2] Consequently, during those hours when a SGIP system is idle, displacement of CO_2 emissions from central station power plants is equal to zero.

[3] Energy and Environmental Economics, Inc. Methodology and Forecast 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

[4] Since virtually all carbon in natural gas is converted to CO2 during combustion, the amount of CH4 released from incomplete combustion is considered insignificant and is not included in this baseline component.

GHG impacts expressed in terms of CO_2 equivalency (CO_2eq)[5] were calculated by date and time (hereafter referred to as 'hour') as:

$$\Delta GHG_{ih} = SgipGHG_{ih} - \left(BasePpEngo_{ih} + BasePpChiller_{ih} + BaseBlr_{ih} + BaseBio_{ih}\right)$$

where:

ΔGHG_{ih} is the GHG impact for SGIP system *i* for hour *h*.

Units: Metric Tons CO_2eq / hr

Negative GHG impacts (DeltaGHG) indicate a reduction in GHG emissions. Not all SGIP sites include all of the above variables. Inclusion is determined by the SGIP DG technology and fuel type and is discussed further in Sections C.2 and C.3. Section C.2 further describes GHG emissions from SGIP systems (SgipGHG), as well as heating and cooling services associated with combined heat and power (CHP) systems. In Section C.3, baseline GHG emissions are described in detail.

C.2 SGIP System GHG Emissions (SgipGHG)

SGIP systems that consume natural gas or renewable biogas emit CO_2. CO_2 emission rates for the SGIP systems that use gaseous fuel were calculated as:

$$(CO_2)_T \cong \left(\frac{3412 \; Btu}{kWh}\right)\left(\frac{1}{EFF_T}\right)\left(\frac{ft^3 \; of \; CH_4}{1000 \; Btu}\right)\left(\frac{lbmole \; of \; CH_4}{360 \; ft^3}\right)\left(\frac{lbmole \; of \; CO_2}{lbmole \; of \; CH_4}\right)\left(\frac{44 \; lbs \; of \; CO_2}{lbmole \; of \; CO_2}\right)$$

$(CO_2)_T$ is the CO_2 emission rate for technology *T*.

Units: $\frac{lbs \; CO_2}{kWh}$

EFF_T is the electrical efficiency of technology *T*.

Value: Dependent on technology type

Units: Dimensionless fractional efficiency

Basis: Lower heating value (LHV). Metered data collected from SGIP systems.

where: Technology Type	EFF_T
Fuel Cell – CHP	0.38
Fuel Cell – Electric Only	0.47
Gas Turbine	0.33
IC Engine	0.31
Microturbine	0.23

[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.

The technology-specific emission rates were calculated to account for CO_2 emissions from SGIP systems. When multiplied by the electricity generated by these systems, the results represent hourly CO_2 emissions in pounds, which are then converted into metric tons, as shown in the equation below.

$$SgipGHG_{ih} = ((CO_2)_T \times engohr_{ih}) \times \left(\frac{metric \ \ ton \ \ CO_2}{2{,}205 \ \ lbs \ \ CO_2} \right)$$

where:

$SgipGHG_{ih}$ is the CO_2 emitted by SGIP system *i* during hour *h*.

Units: Metric ton / hr

$engohr_{ih}$ is the electrical output of SGIP system *i* during hour *h*.

Units: kWh

Basis: Net of any parasitic losses.
Metered data collected from SGIP systems.

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 systems, 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 directly into 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 system 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 systems or displaced by absorption chillers operating on heat recovered from CHP SGIP systems.

The service territory of the SGIP site is considered in the development of emission rates by accounting for whether the site is located in PG&E's territory (northern California) or in SCE/SDG&E'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 used 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 CO_2 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 natural gas 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.

$BaseCO2EF_{rh}$ is the CO_2 emission rate for region *r* (northern or southern California) for hour *h*.

Source: E3 workbook

Units: Metric ton / kWh

Electric Power Plant Operations Corresponding to Electric Chiller Operation

An absorption chiller may be used to convert waste heat recovered from CHP SGIP systems into chilled water to serve building 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.

$$COOLING_{ih} = CHILLER_i \times heathr_{ih} \times COP$$

where:

$COOLING_{ih}$ is the cooling services provided by CHP SGIP system *i* for hour *h*.

Units: kBtu

$CHILLER_i$ is an allocation factor whose value depends on CHP SGIP system design (i.e., Heating Only, Heating & Cooling, or Cooling Only)

Units: Dimensionless

Basis: System design as represented in Installation Verification Inspection Report

System Design	$CHILLER_i$
Heating & Cooling	0.5
Cooling Only	1.0

$heathr_{ih}$ is the quantity of useful heat recovered for CHP SGIP system *i* for hour *h*.

Units: kBtu

Basis: Metering or ratio analysis depending on HEAT metering status

COP is the efficiency of the absorption chiller using heat from the CHP SGIP system.

Value: 0.6

Units: $\frac{kBTU_{out}}{kBTU_{in}}$

Basis: Assumed

The electricity that would have been serving an electric chiller in the absence of the cogeneration system was calculated as:

$$ChlrElec_{ih} = COOLING_{ih}\ kBtu \times \left(EffElecChlr \frac{kWh}{ton \cdot hr\ cooling} \right) \left(\frac{ton \cdot hr\ cooling}{12\ kBtu} \right)$$

where:

$ChlrElec_{ih}$ is the electricity a power plant would have needed to provide for a baseline electric chiller for CHP SGIP system *i* for hour *h*.

Units: kWh

EffElecChlr is the efficiency of the baseline new standard efficiency electric chiller

Value: 0.634

Units: $\frac{kWh}{ton \cdot hr\ cooling}$

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.

$$BasePpChiller_{ih} = \left(BaseCO2EF_{ih} \times ChlrElec_{ih}\right)$$

$$BasePpEngo_{ih} = \left(BaseCO2EF_{ih} \times engohr_{ih}\right)$$

where:

$BasePpChiller_{ih}$ is the baseline power plant GHG emissions avoided due to CHP SGIP system *i* delivery of cooling services for hour *h*.

Units: Metric Tons CO_2 / hr

$BasePpEngo_{ih}$ is the baseline power plant GHG emissions avoided due to CHP SGIP system *i* electricity generation for hour *h*.

Units: Metric Tons CO_2 / hr

A heat exchanger is typically used to transfer useful heat recovered from CHP SGIP systems to building heating loads. The equation below represents the process by which heating services provided by CHP SGIP systems are calculated.

$$HEATING_{ih} = BOILER_{i} \times heathr_{ih} \times EffHx$$

where:

$HEATING_{ih}$ is the heating services provided by CHP SGIP system *i* for hour *h*.

Units: kBtu

$BOILER_i$ is an allocation factor whose value depends on CHP SGIP system design (i.e., Heating Only, Heating & Cooling, or Cooling Only)

Units: Dimensionless

Basis: System design as represented in Installation Verification Inspection Report

System Design	$BOILER_i$
Heating & Cooling	0.5
Heating Only	1.0

$heathr_{ih}$ is the quantity of useful heat recovered and used for heating services for CHP SGIP system *i* for hour *h*.

Units: kBtu

Basis: Metering or ratio analysis depending on HEAT metering status

EffHx is the efficiency of the CHP SGIP system'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 CHP SGIP systems as follows:

$$BaseBlr_{ih} = \left(HEATING_{ih}\ \mathrm{kBtu}_{out} \times \left(\frac{1}{EffBlr \dfrac{\mathrm{kBtu}_{out}}{\mathrm{kBtu}_{in}}} \right) \left(\frac{ft^3\ of\ CH_4}{1\ kBtu_{in}} \right) \left(\frac{lbmole\ \ of\ \ CO_2}{360\ \ ft^3\ \ of\ \ CH_4} \right) \left(\frac{44\ \ lbs\ \ of\ \ CO_2}{lbmole\ \ of\ \ CO_2} \right) \right)$$

$$\times \left(\frac{metrictonCO_2}{2,205\ \ lbsCO_2} \right)$$

where:

BaseBlr$_{ih}$ is the CO_2 emissions of the baseline natural gas boiler for CHP SGIP system *i* for hour *h*.

Units: Metric Tons CO_2 / hr

EffBlr is the efficiency of the baseline natural gas boiler

Value: 0.8

Units: $\frac{kBtu_{out}}{kBtu_{in}}$

Basis: Previous program cost-effectiveness evaluations.

This equation reflects the ability to use recovered waste heat in lieu of natural gas and, therefore, help reduce CO_2 emissions.

Biogas GHG Emissions (BaseBio)

DG facilities 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 systems. 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-PY12 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-PY12 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 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.

[6] Most dairies manage their wastes 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 systems).

[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

In CPUC Decision 09-09-048 (September 24, 2009), eligibility for renewable fuel use incentives was expanded to include "directed biogas" projects. Deemed to be 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 we made the following assumptions:

- *The renewable fuel baseline for all directed biogas projects is flaring of 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.*

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 at 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 create energy, 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 system to produce electricity.

$$BaseBio_{ih} = SgipGHG_{ih}$$

[8] Information on consumption of directed biogas at SGIP projects is based on invoices instead of metered data.

[9] From a financial feasibility perspective, directed biogas was assumed to be procured only from large biogas sources, such as large landfills. In accordance with Environmental Protection Agency 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.

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 to the atmosphere. The venting baseline was assumed for all dairy digester SGIP sites. Biogas consumption is typically not metered at SGIP sites. Therefore, CH_4 emission rates were calculated by assuming an electrical efficiency.

$$CH4EF_T \cong \left(\frac{3412\ Btu}{kWh}\right)\left(\frac{1}{EFF_T}\right)\left(\frac{ft^3\ of\ CH_4}{1000\ Btu}\right)\left(\frac{lbmole\ of\ CH_4}{360\ ft^3\ of\ CH_4}\right)\left(\frac{16\ lb_m\ of\ CH_4}{lbmole\ of\ CH_4}\right)\left(\frac{454\ grams}{lb_m\ of\ CH_4}\right)$$

where:

$CH4EF_T$ is the CH_4 capture rate for SGIP systems of technology T

Units: $\frac{grams}{kWh}$

EFF_T is the electrical efficiency of technology *T*.

Units: Dimensionless fractional efficiency

Basis: Lower heating value (LHV).
Metered data collected from natural gas CHP SGIP systems.

Technology Type	EFF_T
IC Engine	0.30

The derived CH_4 emission rates (*CH4EF*) are multiplied by the total electricity generated from the SGIP renewable fuel use sites to estimate baseline CH_4 emissions.

$$BaseBioCH4_{ih} = \left(\left(\frac{CH_4EF_T\ grams}{kWh}\right)(engohr_{ih})\left(\frac{0.002204\ lbs}{grams}\right)\right)\times\left(\frac{metrictonCH_4}{2,205\ lbsCH_4}\right)$$

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 (GWP) of CH_4 (relative to CO_2) over a 100-year time horizon.

$$BaseBio_{ih} = BaseBioCH4_{ih} * \left(\frac{21\ metrictons\ CO_2}{metricton\ CH_4}\right)$$

C.4 Summary of GHG Impact Results

Table C-1: GHG Impacts by Technology and Fuel Type

Technology / Fuel†*	*GHG Impact (Metric Tons CO_2eq)*	*Electricity Impact (MWh)*	*GHG Impact Rate (Metric Tons CO_2eq / MWh)*
FC – CHP	**-13,907**	**88,552**	**-0.16**
N	-173	58,072	-0.00
R - Flared	-13,734	30,480	-0.45
FC - Electric	**-72,840**	**287,174**	**-0.25**
N	-4,650	92,486	-0.05
R - Directed	-67,207	192,517	-0.35
R - Flared	-982	2,171	-0.45
GT	**-3,903**	**220,271**	**-0.02**
N	-3,903	220,271	-0.02
IC Engine	**-52,659**	**301,468**	**-0.17**
N	1,308	243,974	0.01
R - Flared	-25,704	51,302	-0.50
R - Vented	-28,264	6,192	-4.56
MT	**14,828**	**72,611**	**0.20**
N	16,645	68,548	0.24
R - Flared	-1,816	4,064	-0.45

* C*F – CHP = CHP Fuel Cell, FC – Electric = All Electric Fuel Cell, GT = Gas Turbine, IC Engine = Internal Combustion Engine, MT – Microturbine*

† *N = Natural Gas, R – Directed = Directed Biogas, R – Flared = Renewable with Flared Baseline, R – Vented = Renewable with Vented Baseline*

Table C-2: GHG Impacts by Program Administrator and Technology Type

PA / Technology*	*GHG Impact (Metric Tons CO_2eq)*	*Electricity Impact (MWh)*	*GHG Impact Rate (Metric Tons CO_2eq / MWh)*
CCSE	**-15,818**	**149,826**	**-0.11**
FC - CHP	39	8,629	0.00
FC – Electric	-16,401	48,987	-0.33
GT	2,193	78,714	0.03
IC Engine	-1,650	11,601	-0.14
MT	2	1,896	0.00
PG&E	**-69,008**	**397,704**	**-0.17**
FC – CHP	-3,241	48,720	-0.07
FC – Electric	-32,445	145,651	-0.22
GT	-979	18,006	-0.05
IC Engine	-40,122	142,292	-0.28
MT	7,779	43,036	0.18
SCE	**-25,115**	**129,354**	**-0.19**
FC – CHP	-5,666	14,409	-0.39
FC – Electric	-14,928	59,637	-0.25
IC Engine	-6,916	45,218	-0.15
MT	2,395	10,091	0.24
SCG	**-18,539**	**293,192**	**-0.06**
FC – CHP	-5,039	16,795	-0.30
FC - Electric	-9,065	32,900	-0.28
GT	-5,117	123,550	-0.04
IC Engine	-3,971	102,358	-0.04
MT	4,653	17,589	0.26

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

Table C-3: GHG Impacts by Program Administrator and Fuel Type

PA / Fuel Type	*GHG Impact (Metric Tons CO_2eq)*	*Electricity Impact (MWh)*	*GHG Impact Rate (Metric Tons CO_2eq / MWh)*
CCSE	**-15,818**	**149,826**	**-0.11**
N	2,731	98,907	0.03
R - Directed	-15,268	43,627	-0.35
R - Flared	-3,282	7,292	-0.45
PG&E	**-69,008**	**397,704**	**-0.17**
N	3,987	276,316	0.01
R - Directed	-29,428	84,608	-0.35
R - Flared	-15,303	30,588	-0.50
R - Vented	-28,264	6,192	-4.56
SCE	**-25,115**	**129,354**	**-0.19**
N	1,774	63,425	0.03
R - Directed	-13,863	39,391	-0.35
R - Flared	-13,026	26,539	-0.49
SCG	**-18,539**	**293,192**	**-0.06**
N	734	244,704	0.00
R - Directed	-8,649	24,891	-0.35
R - Flared	-10,624	23,597	-0.45

Appendix D

APPENDIX D
SOURCES OF UNCERTAINTY

This appendix provides an assessment of the uncertainty associated with program 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 those reported results are quite different for these two types of program impacts. The treatment of those factors is described below for each of the two types of impacts.

Uncertainty estimates are provided for annual and coincident peak electrical impacts.

D.1 Energy (Electricity, Fuel, and Heat) Impacts

Electricity, fuel, and heat impact estimates are affected by at least two sources of error that introduce uncertainty into the 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 impact estimates are based on results of this analysis.

For this impact evaluation an empirical approach known as Monte Carlo Simulation (MCS) analysis was used to quantify impact 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 analytic questions. This is an important advantage for this project because numerous factors contribute to variability in impact

[1] Webster's Dictionary.

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 cogeneration systems, whereas other systems may also include metered fuel usage, while still others might have other combinations of data available.

D.2 Greenhouse Gas Emission Impacts

Electricity and fuel impact estimates represent the starting point for the analysis of Greenhouse Gas (GHG) emission impacts; thus, uncertainty in those electricity and fuel impact estimates flows down to the GHG emissions impact estimates. However, additional sources of uncertainty are introduced in the course of the GHG emissions impacts 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 net GHG emissions impacts of each SGIP system involves comparing emissions of the SGIP system 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 system had not been installed. Data concerning marginal baseline generation technologies and their efficiencies (and, hence, GHG emissions factors) were obtained from E3. Quantitative assessment of uncertainty in E3's avoided GHG emissions database is outside the scope of this SGIP impact evaluation.

Baseline Biogas Project GHG Emissions

Biomass material (e.g., trash in landfills, manure at 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).

For this GHG impact evaluation Itron used the CH_4 disposition baseline assumptions summarized in Table D-1. Due to the influential nature of this factor, and given the current relatively high level of uncertainty surrounding assumed baselines, Itron continues collecting additional site-specific information about CH_4 disposition and incorporating it into impacts analyses. Modification of installation verification inspection forms will be recommended, and information available from air permitting and other information sources will be compiled.

Table D-1: CH_4 Disposition Baseline Assumptions for Biogas Projects

Renewable Fuel Facility Type	*Methane Disposition Baseline Assumption*
Dairy Digester	Venting
Waste Water Treatment Landfill Gas Recovery Directed Biogas	Flaring

D.3 Data Sources

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 systems for which impact estimates are being reported. Several key sources of data for these factors are described briefly below.

SGIP Project Information

Basic project identifiers include PA, project status, project location, system type, and system size. This information is obtained from project lists that PAs maintain for the CPUC. More detailed project information (e.g., heat exchanger configuration) is obtained from Verification Inspection Reports developed by PAs just prior to issuance of incentive checks.

Metered Data for SGIP DG Systems

Collection and analysis of metered performance data collected from SGIP DG systems is a central focus of the overall program evaluation effort. In the MCS study the metered performance data are used for three 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 central tendencies of groups of metered data are used to estimate the actual performance of unmetered systems.
3. The variability characteristics exhibited by groups of metered data contribute to development of distributions used in the MCS study to explore the likelihood that actual performance 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 values and actual performance.

D.4 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*

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 systems came online during 2012 and, therefore, contributed to energy impacts for only a portion of the year. Some of the systems for which metered data are available have gaps in the metered data archive that required estimation of impacts for a portion of hours during 2012. 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 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 2012 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 labor and 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 system is metered. However, for many of the SGIP systems, metered data are available for a portion—but not all—of 2012. This complicates any analysis that requires classification of systems 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, heat) for each month of 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 of each unmetered system based on research performed[2].

[2] This research primarily involved contacting site hosts to determine the operational status of unmetered systems.

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 system then the actual values are created by applying a measurement error to the metered values. If metered data are not available for the system, the actual values are created using distributions that reflect performance variability assumptions. *A total of 10,000 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 D-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 D-2: Summary of Random Measurement Error Variables

Measurement	*Range*	*Mean*	*Distribution*
Electricity	-0.5% to 0.5%		
Natural Gas	-2% to 2%	0%	Uniform
Heat Recovered	-5% to 5%		

Metered Data Unavailable – Generating Sample Data from Performance Distributions

In the case of unmetered sites, the sample data are generated by random assignment from distributions of performance values assumed representative of entire groups of unmetered sites. Because measured performance data are not available for any of these sites, the natural place to look first for performance values is similar metered systems.

Specification of performance distributions for the MCS study involves a degree of judgment in at least two areas: first, 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 systems; second, when 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 D-3 shows the groups used to estimate the uncertainty in the CAISO peak hour impact.

Table D-3: Performance Distributions Developed for the 2012 CAISO Peak Hour MCS Analysis

Technology	***Fuel***	***PA***
Wind[3]	N/A	N/A
IC Engine	Non Renewable, Renewable	All
Microturbine	Non Renewable, Renewable	All
Gas Turbine	Non Renewable[4]	All
Fuel Cell	Non Renewable, Renewable	All

Table D-4 shows the groups used to estimate the uncertainty in the yearly energy production. Internal combustion (IC) 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 and because a significant difference was not seen between the annual capacity factors of these systems.

Table D-4: Performance Distributions Developed for the 2012 Annual Energy Production MCS Analysis

Technology	***Fuel***
Wind	N/A
Engine/Turbine	Non Renewable, Renewable
Fuel Cell	Non Renewable, Renewable

Performance distributions were developed for each of the groups in the tables 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 capacity factor and system size. All of these performance distributions are shown in Figure D-1 through Figure D-12.

[3] MCS analysis was not conducted for wind turbine impacts due to lack of available metered data.

[4] There are no renewable-fueled gas turbines in the program as of December 31, 2012.

Performance Distributions for Coincident Peak Demand Impacts

Figure D-1: MCS Distribution – Fuel Cell Coincident Peak Output (Non-Renewable Fuel)

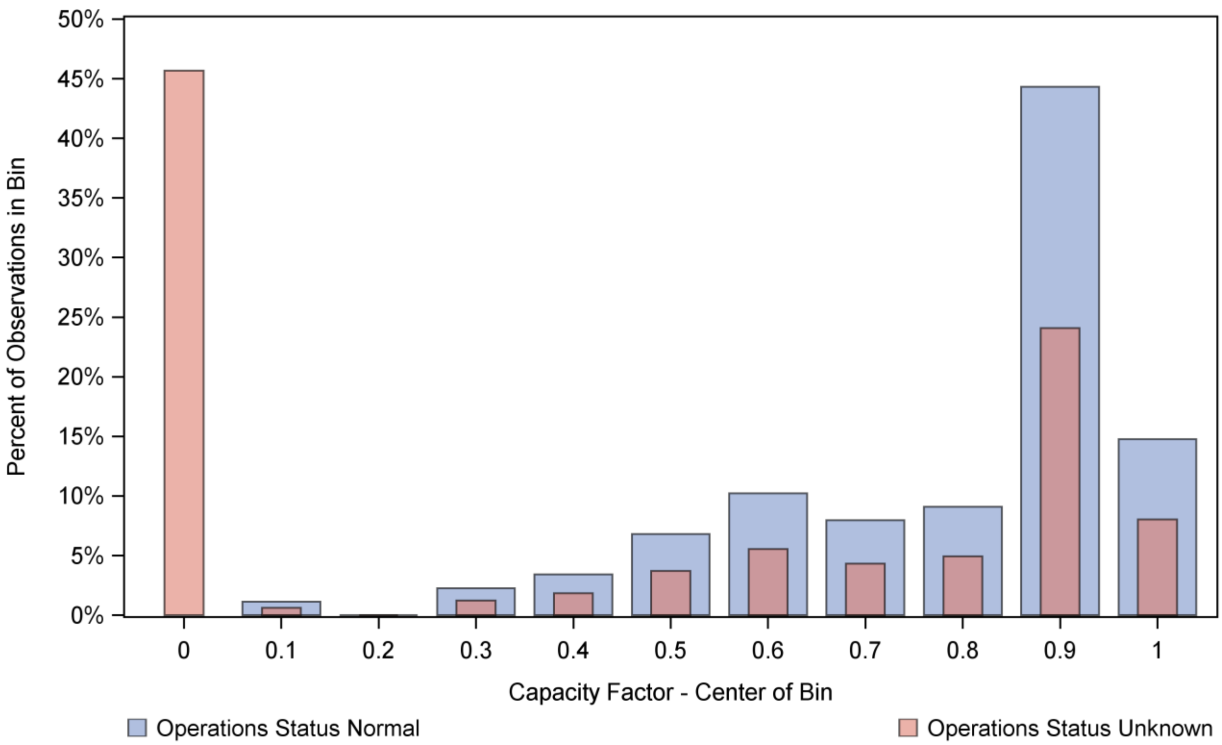


Figure D-2: MCS Distribution – Fuel Cell Coincident Peak Output (Renewable Fuel)

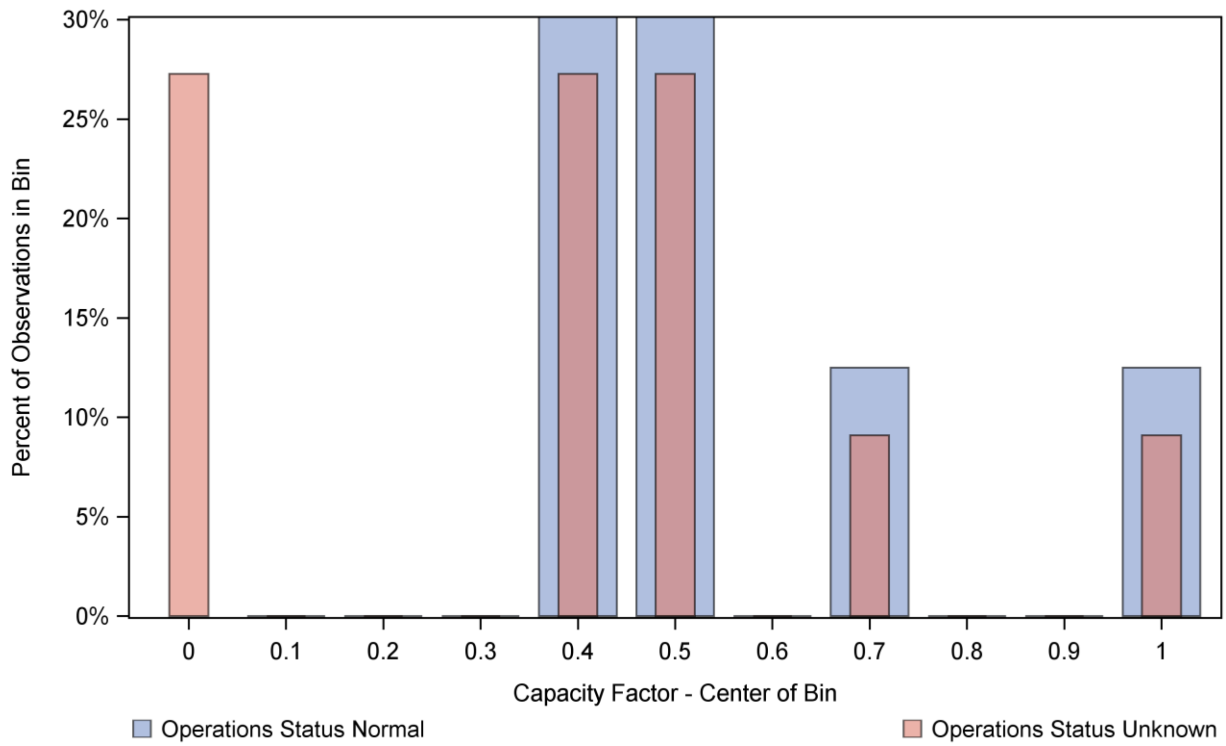


Figure D-3: MCS Distribution - Gas Turbine Coincident Peak Output (Non-Renewable Fuel)

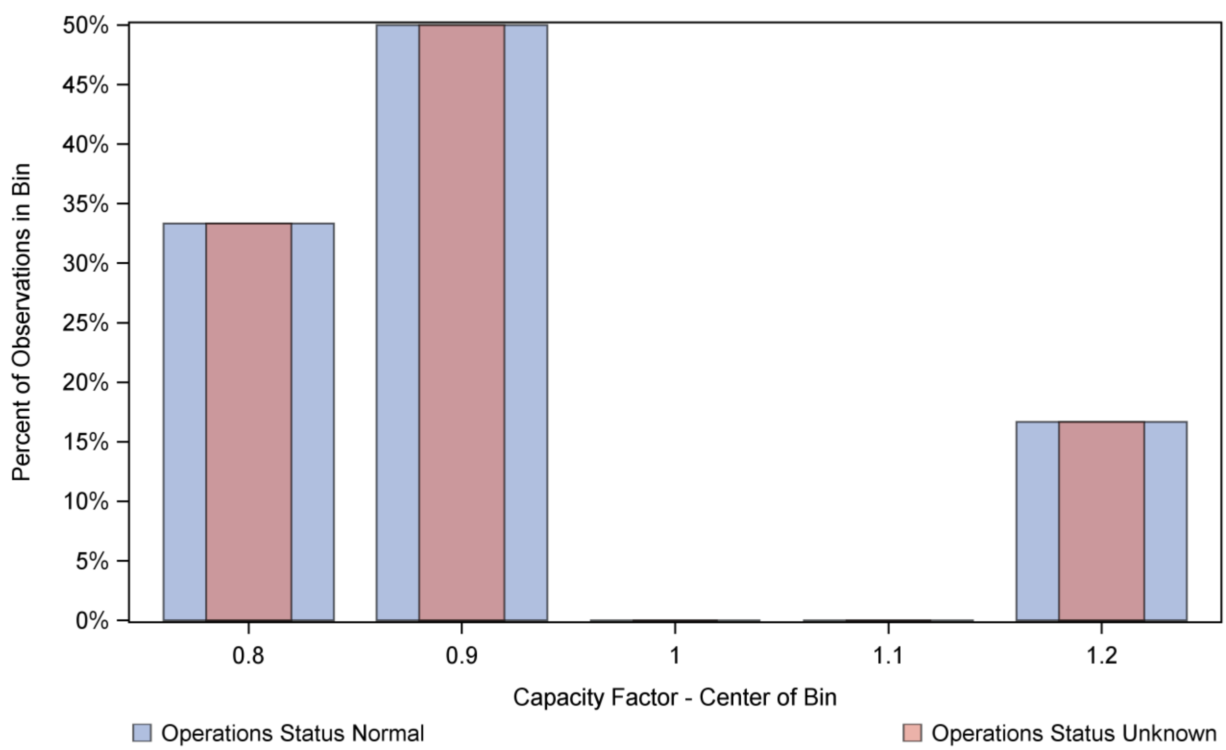


Figure D-4: MCS Distribution - IC Engine Coincident Peak Output (Non-Renewable Fuel)

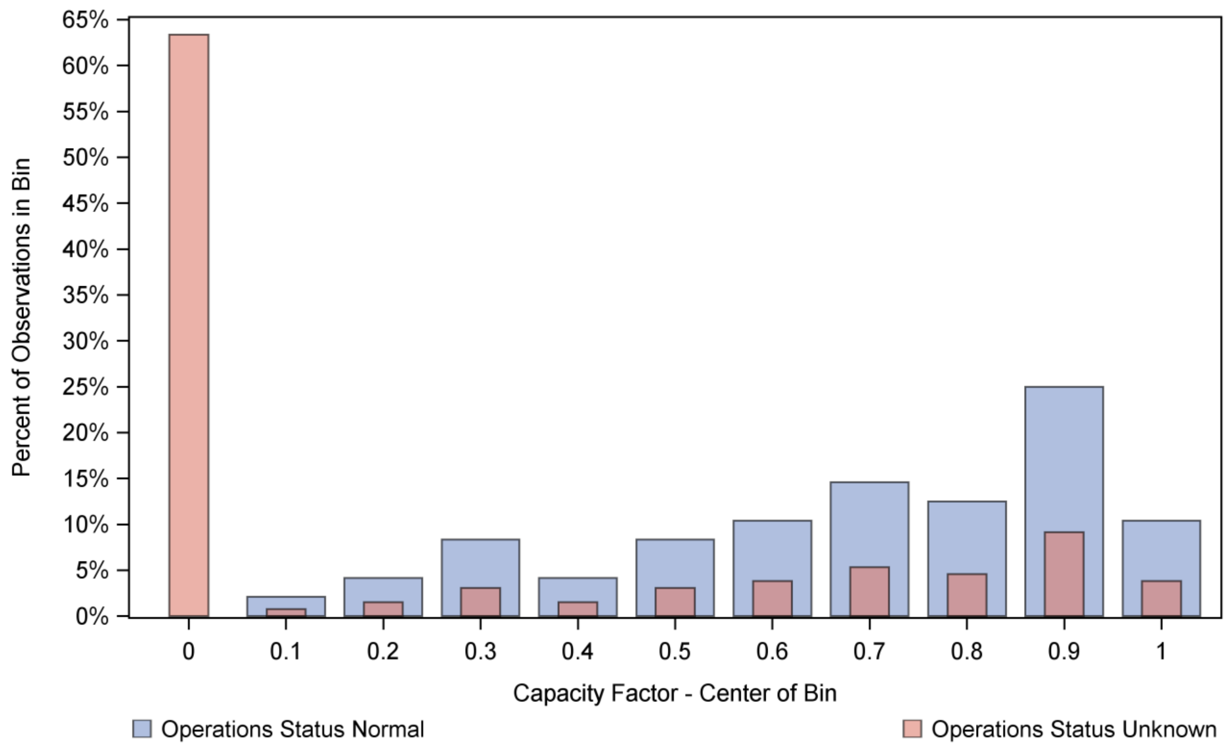


Figure D-5: MCS Distribution - IC Engine Coincident Peak Output (Renewable Fuel)

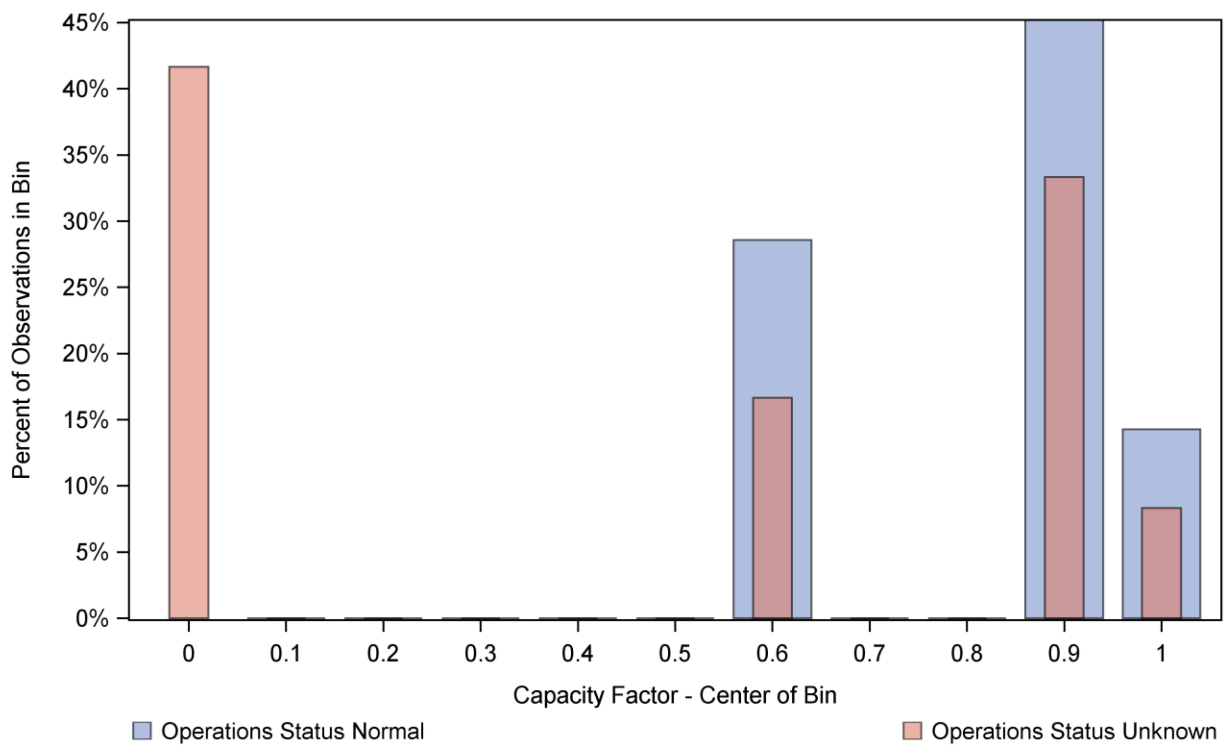


Figure D-6: MCS Distribution - Microturbine Coincident Peak Output (Non-Renewable Fuel)

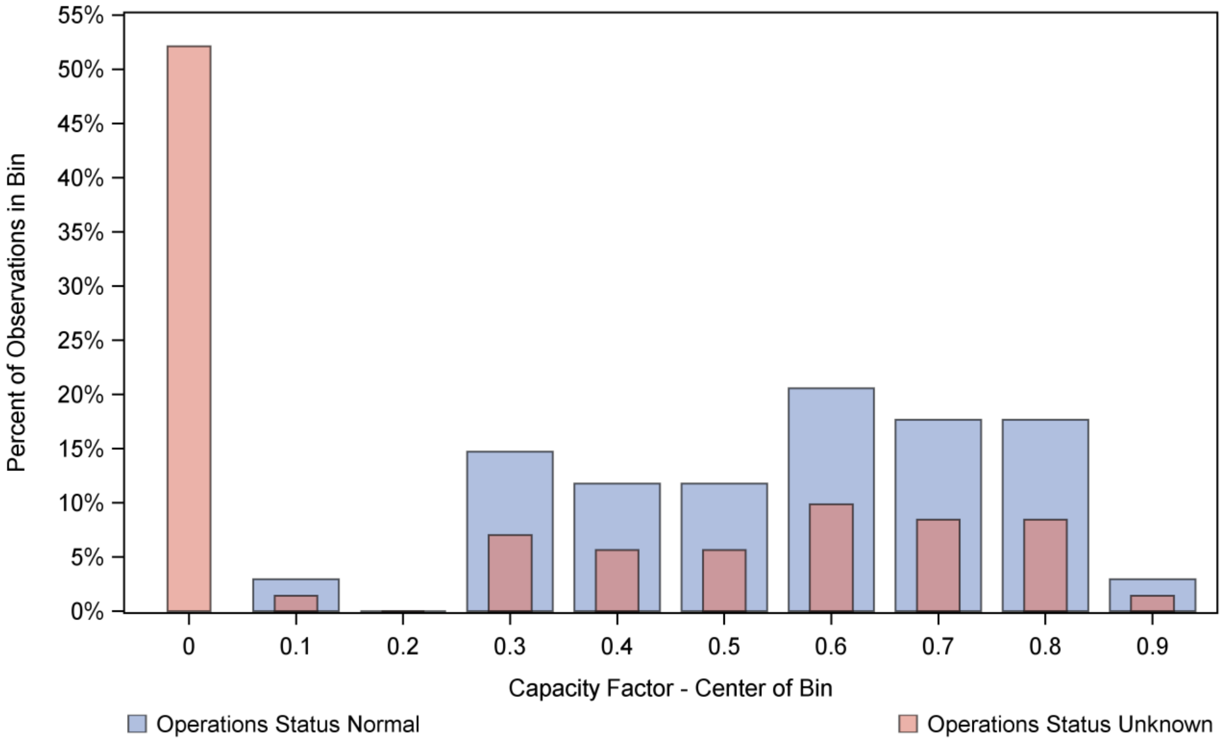
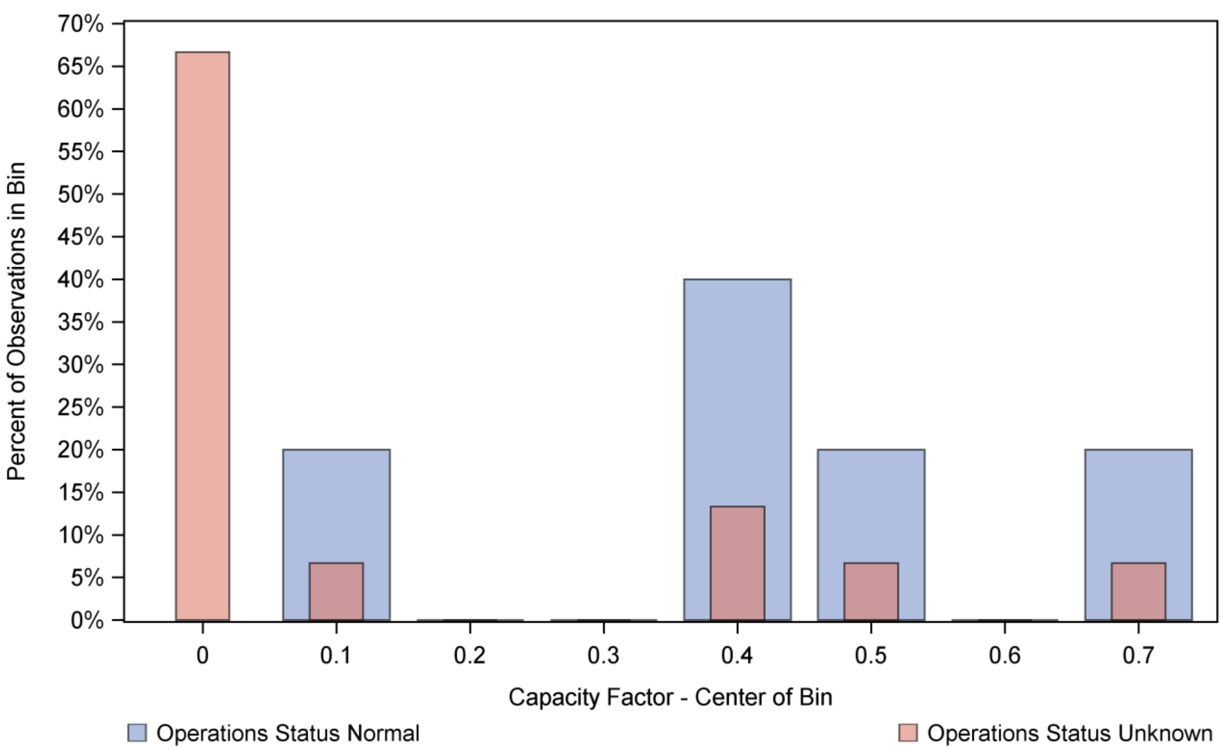


Figure D-7: MCS Distribution - Microturbine Coincident Peak Output (Renewable Fuel)



Performance Distributions for Energy Impacts

Figure D-8: MCS Distribution–Engine/Turbine (Non-Renewable) Energy Production (Capacity Factor)

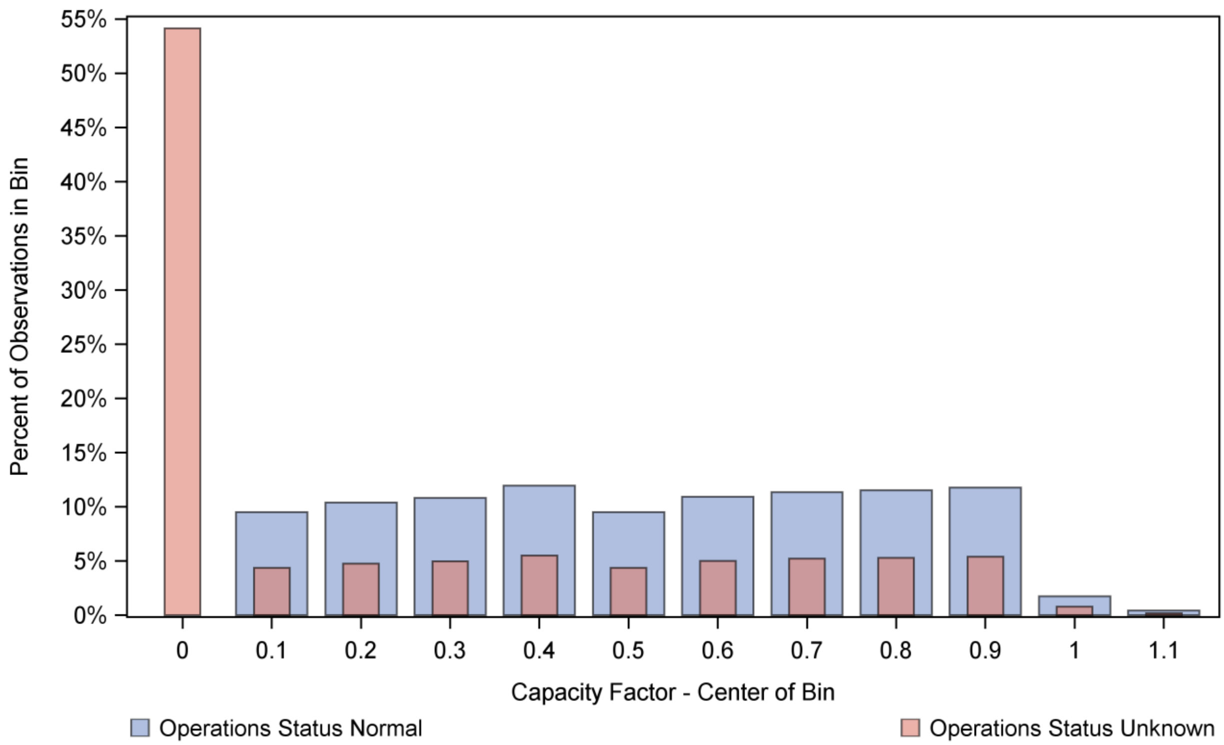


Figure D-9: MCS Distribution – Engine/Turbine (Renewable) Energy Production (Capacity Factor)

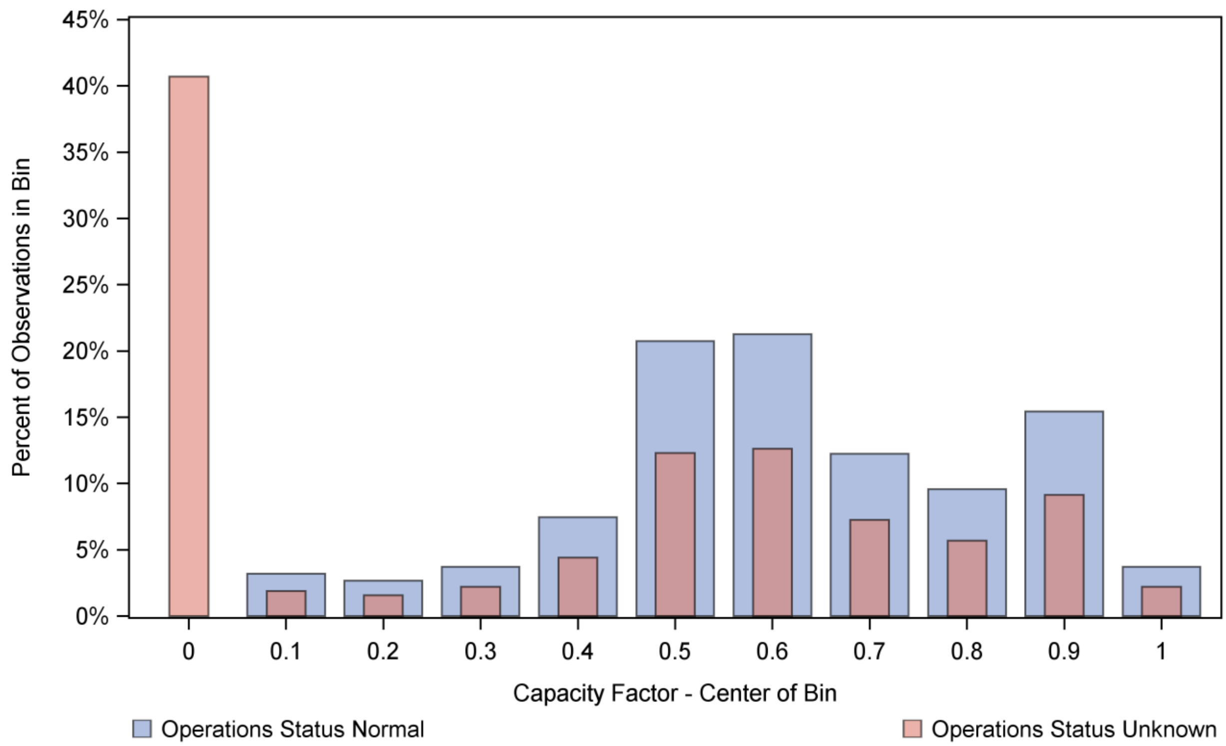


Figure D-10: MCS Distribution - Fuel Cell Energy Production (Capacity Factor)

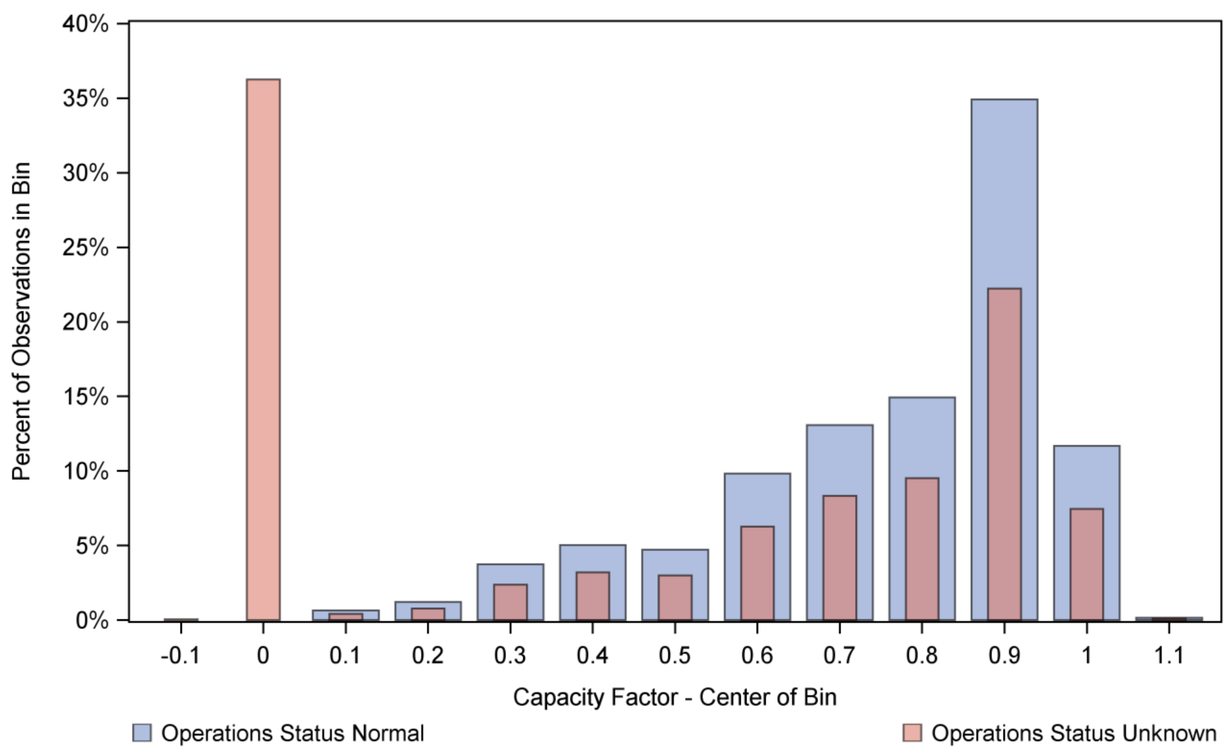


Figure D-11: MCS Distribution - Engine/Turbine Heat Recovery Rate

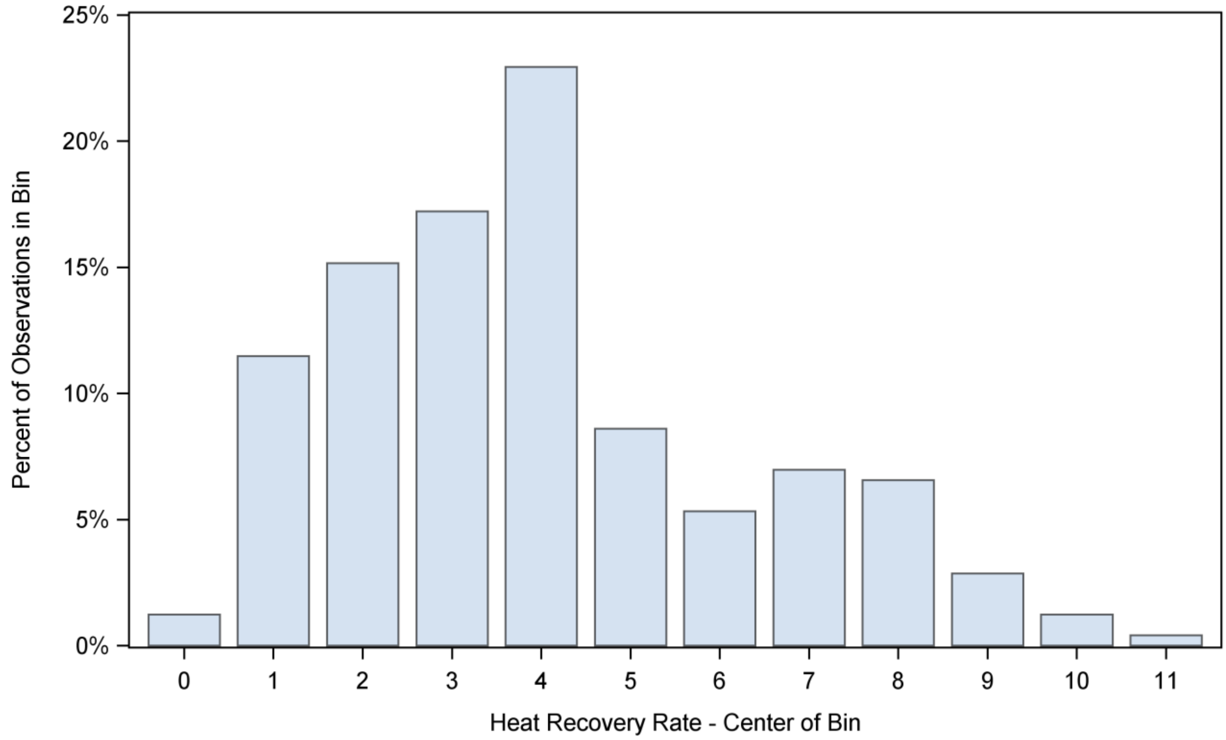
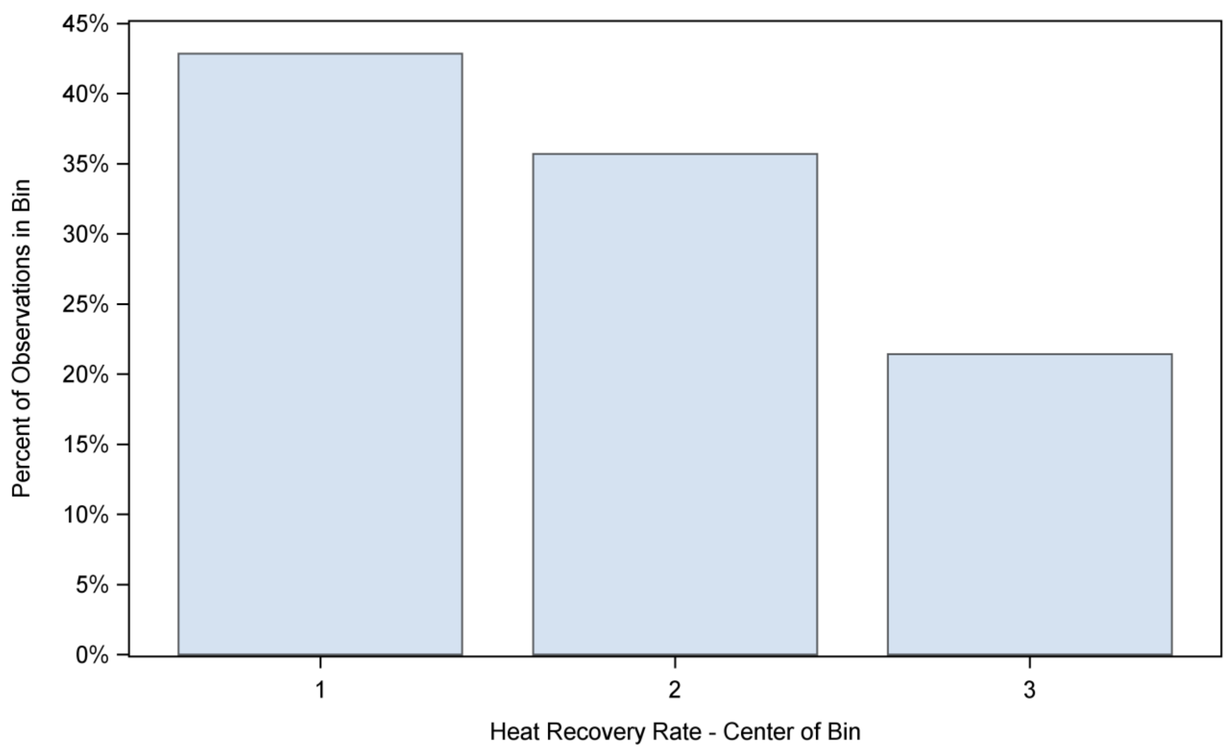


Figure D-12: MCS Distribution - Fuel Cell Heat Recovery Rate



Bias

Performance data collected from metered sites were used to estimate program impacts attributable to unmetered sites. If the metered sites are not representative of the unmetered sites then those estimates will include systematic error called bias. Potential sources of bias of principle concern for this study include:

Planned data collection disproportionally favors dissimilar groups. HEAT metering is typically installed on projects which are still under their contract with SGIP. If the actual heat recovery performance of the older systems differs systematically from the newer metered systems then estimates calculated for the older systems will be biased. A similar situation can occur when actual performance differs substantially from performance assumptions underlying data collection plans.

Actual data collection allocations deviate from planned data collection allocations. In program impact evaluation studies, actual data collection almost invariably deviates somewhat from planned data collection. If the deviation is systematic rather than random then estimates calculated for unmetered systems may be biased. For example, metered data for a number of fuel cell systems 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 systems differs systematically from that of the systems metered by participants then estimates calculated for the unmetered systems will be biased. One example of this is if a participant metered system's output decreases unexpectedly the participant will know almost immediately and steps can be taken to get the system running normally again. However, a similar situation with an unmetered system could go unnoticed for months.

Actual data collection quantities deviate from planned data collection quantities. For example, plans called for collection of ENGO data from all renewable fuel use systems; however, data were actually collected only from a small proportion of completed renewable fuel use systems.

In the MCS analysis bias is accounted for during development of performance distributions assumed for unmetered systems. 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 project 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 sites. Due to the relative magnitudes involved, instrumentation error—if it exists—accounts for an insignificant portion or total bias contained in point estimates.

It is important to note that possible sampling bias affects only impacts estimates calculated for unmetered sites. The relative importance of this varies with metering rate. For example, where the metering rate is 90%, a 20% sampling bias will yield an error of only 2% 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 sites 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 constant relative precision), or to determine confidence intervals (under the constraint of constant confidence level).

D.5 Results

The confidence levels in the energy and impacts results have been presented along with those results. This section will present the precision and confidence intervals associated with those confidence levels in more detail. Three bins were used for Confidence Levels: 90/10 or better, 70/30 or better (but worse than 90/10), and worse than 70/30.

Table D-5: Uncertainty Analysis Results for Annual Energy Impact Results by Technology and Basis

Technology* / Basis	Confidence Level	Precision†	Confidence Interval†
FC	**90%**	**1.34%**	**0.650 to 0.668**
Metered	90%	0.02%	0.699 to 0.699
Estimated	70%	7.33%	0.425 to 0.493
GT	**90%**	**2.50%**	**0.731 to 0.768**
Metered	90%	0.06%	0.823 to 0.824
Estimated	70%	14.70%	0.365 to 0.491
IC Engine	**90%**	**3.70%**	**0.212 to 0.228**
Metered	90%	0.02%	0.186 to 0.186
Estimated	90%	8.44%	0.261 to 0.310
MT	**90%**	**4.08%**	**0.281 to 0.305**
Metered	90%	0.03%	0.301 to 0.301
Estimated	70%	11.19%	0.239 to 0.299

** FC = Fuel Cell, GT = Gas Turbine, IC Engine = Internal Combustion Engine, MT = Microturbine*

† Both precision and confidence interval are given according to the corresponding confidence level. In cases where an accuracy level of 90% confidence and 10% precision (i.e., 90/10) was not achieved the reported precision values and confidence intervals are based on a 70% confidence level.

Table D-6: Uncertainty Analysis Results for Annual Energy Impact Results by Technology, Fuel, and Basis

Technology & Fuel / Basis	*Confidence Level*	*Precision*	*Confidence Interval*
FC-N	**90%**	**1.20%**	0.682 to 0.699
Metered	90%	0.02%	0.734 to 0.734
Estimated	70%	7.04%	0.429 to 0.493
FC-R	**90%**	**7.68%**	0.436 to 0.509
Metered	90%	0.06%	0.480 to 0.480
Estimated	70%	25.57%	0.333 to 0.562
GT-N	**90%**	**2.50%**	0.731 to 0.768
Metered	90%	0.06%	0.823 to 0.824
Estimated	70%	14.70%	0.365 to 0.491
IC Engine-N	**90%**	**4.28%**	0.193 to 0.210
Metered	90%	0.03%	0.164 to 0.164
Estimated	90%	9.26%	0.251 to 0.302
IC Engine-R	**90%**	**5.72%**	0.361 to 0.405
Metered	90%	0.05%	0.389 to 0.390
Estimated	70%	11.05%	0.328 to 0.409
MT-N	**90%**	**4.36%**	0.305 to 0.333
Metered	90%	0.03%	0.342 to 0.342
Estimated	70%	12.96%	0.221 to 0.287
MT-R	**70%**	**7.12%**	0.176 to 0.203
Metered	90%	0.07%	0.151 to 0.151
Estimated	70%	19.96%	0.285 to 0.427

Table D-7: Uncertainty Analysis for CCSE Annual Energy Impact

Technology / Basis	*Confidence Level*	*Precision*	*Confidence Interval*
FC	**90%**	**2.38%**	**0.613 to 0.642**
Metered	90%	0.06%	0.643 to 0.643
Estimated	70%	17.40%	0.413 to 0.586
GT	**90%**	**0.10%**	**0.981 to 0.983**
Metered	90%	0.10%	0.981 to 0.983
Estimated	N/A	N/A	N/A
IC Engine	**90%**	**5.78%**	**0.120 to 0.135**
Metered	90%	0.08%	0.120 to 0.120
Estimated	70%	31.60%	0.174 to 0.335
MT	**90%**	**3.56%**	**0.114 to 0.123**
Metered	90%	0.08%	0.114 to 0.114
Estimated	70%	36.28%	0.181 to 0.387

Table D-8: Uncertainty Analysis Results for PG&E Annual Energy Impact

Technology / Basis	*Confidence Level*	*Precision*	*Confidence Interval*
FC	**90%**	**1.30%**	**0.712 to 0.731**
Metered	90%	0.02%	0.764 to 0.765
Estimated	70%	10.16%	0.396 to 0.485
GT	**70%**	**19.47%**	**0.178 to 0.265**
Metered	90%	0.24%	0.042 to 0.042
Estimated	70%	21.12%	0.276 to 0.423
IC Engine	**90%**	**6.36%**	**0.221 to 0.251**
Metered	90%	0.03%	0.201 to 0.201
Estimated	70%	8.61%	0.268 to 0.319
MT	**90%**	**6.64%**	**0.330 to 0.377**
Metered	90%	0.05%	0.398 to 0.398
Estimated	70%	16.83%	0.220 to 0.309

Table D-9: Uncertainty Analysis Results for SCE Annual Energy Impact

Technology / Basis	*Confidence Level*	*Precision*	*Confidence Interval*
FC	**90%**	**3.90%**	**0.592 to 0.640**
Metered	90%	0.04%	0.683 to 0.683
Estimated	70%	10.92%	0.412 to 0.513
IC Engine	**90%**	**8.07%**	**0.181 to 0.212**
Metered	90%	0.05%	0.149 to 0.149
Estimated	70%	9.77%	0.255 to 0.310
MT	**70%**	**6.46%**	**0.207 to 0.235**
Metered	90%	0.06%	0.195 to 0.196
Estimated	70%	17.90%	0.237 to 0.340

Table D-10: Uncertainty Analysis Results for SCG Annual Energy Impact

Technology / Basis	*Confidence Level*	*Precision*	*Confidence Interval*
FC	**90%**	**5.81%**	**0.525 to 0.590**
Metered	90%	0.04%	0.575 to 0.575
Estimated	70%	28.30%	0.335 to 0.599
GT	**90%**	**3.85%**	**0.720 to 0.778**
Metered	90%	0.08%	0.812 to 0.814
Estimated	70%	19.58%	0.389 to 0.579
IC Engine	**90%**	**5.67%**	**0.221 to 0.248**
Metered	90%	0.05%	0.212 to 0.212
Estimated	70%	8.67%	0.253 to 0.301
MT	**90%**	**3.05%**	**0.297 to 0.315**
Metered	90%	0.06%	0.314 to 0.314
Estimated	70%	16.59%	0.211 to 0.295

Table D-11: Uncertainty Analysis Results for Peak Demand Impact

Technology / Basis	*Confidence Level*	*Precision*	*Confidence Interval*
FC	**90%**	**2.87%**	**0.631 to 0.668**
Metered	90%	0.06%	0.668 to 0.669
Estimated	70%	36.63%	0.267 to 0.575
GT	**90%**	**9.20%**	**0.821 to 0.987**
Metered	90%	0.21%	0.956 to 0.960
Estimated	70%	23.90%	0.588 to 0.958
IC Engine	**70%**	**6.78%**	**0.266 to 0.304**
Metered	90%	0.09%	0.271 to 0.271
Estimated	70%	17.74%	0.256 to 0.366
MT	**70%**	**9.04%**	**0.240 to 0.288**
Metered	90%	0.11%	0.268 to 0.269
Estimated	70%	39.04%	0.152 to 0.346

Table D-12: Uncertainty Analysis Results for Peak Demand Impact Results by Technology, Fuel, and Basis for CCSE

Technology & Fuel / Basis	Confidence Level	Precision	Confidence Interval
FC-N	**90%**	**8.86%**	**0.521 to 0.622**
Metered	90%	0.25%	0.585 to 0.588
Estimated	70%	100.0%	0.000 to 0.780
FC-R	**90%**	**0.45%**	**0.968 to 0.977**
Metered	90%	0.45%	0.968 to 0.977
Estimated	N/A	N/A	N/A
GT-N	**90%**	**0.34%**	**1.067 to 1.074**
Metered	90%	0.34%	1.067 to 1.074
Estimated	N/A	N/A	N/A
IC Engine-N	**70%**	**12.26%**	**0.120 to 0.154**
Metered	90%	0.36%	0.127 to 0.127
Estimated	70%	100.0%	0.000 to 0.655
IC Engine-R	**90%**	**0.45%**	**0.867 to 0.875**
Metered	90%	0.45%	0.867 to 0.875
Estimated	N/A	N/A	N/A
MT-N	**90%**	**4.93%**	**0.210 to 0.232**
Metered	90%	0.24%	0.216 to 0.217
Estimated	70%	100.0%	0.000 to 0.700
MT-R	**90%**	**0.45%**	**0.105 to 0.106**
Metered	90%	0.45%	0.105 to 0.106
Estimated	N/A	N/A	N/A

Table D-13: Uncertainty Analysis Results for Peak Demand Impact Results by Technology, Fuel, and Basis for PG&E

Technology & Fuel / Basis	Confidence Level	Precision	Confidence Interval
FC-N	**90%**	**1.99%**	**0.756 to 0.786**
Metered	90%	0.08%	0.784 to 0.786
Estimated	70%	62.42%	0.160 to 0.692
FC-R	**90%**	**0.35%**	**0.473 to 0.476**
Metered	90%	0.35%	0.473 to 0.476
Estimated	N/A	N/A	N/A
GT-N	**70%**	**23.52%**	**0.577 to 0.933**
Metered	90%	0.45%	0.765 to 0.772
Estimated	70%	33.97%	0.494 to 1.003
IC Engine-N	**70%**	**13.60%**	**0.251 to 0.330**
Metered	90%	0.13%	0.281 to 0.282
Estimated	70%	33.58%	0.203 to 0.408
IC Engine-R	**70%**	**32.52%**	**0.274 to 0.539**
Metered	90%	0.29%	0.356 to 0.358
Estimated	70%	67.89%	0.154 to 0.804
MT-N	**70%**	**16.41%**	**0.315 to 0.438**
Metered	90%	0.18%	0.429 to 0.431
Estimated	70%	63.10%	0.103 to 0.454
MT-R	**70%**	**49.36%**	**0.034 to 0.099**
Metered	90%	0.28%	0.040 to 0.041
Estimated	70%	100.0%	0.000 to 0.385

Table D-14: Uncertainty Analysis Results for Peak Demand Impact Results by Technology, Fuel, and Basis for SCE

Technology & Fuel / Basis	Confidence Level	Precision	Confidence Interval
FC-N	**70%**	**8.89%**	**0.600 to 0.717**
Metered	90%	0.13%	0.714 to 0.716
Estimated	70%	68.39%	0.136 to 0.725
FC-R	**70%**	**20.31%**	**0.270 to 0.408**
Metered	90%	0.29%	0.335 to 0.337
Estimated	70%	100.0%	0.000 to 0.700
IC Engine-N	**70%**	**18.75%**	**0.185 to 0.270**
Metered	90%	0.19%	0.190 to 0.191
Estimated	70%	38.84%	0.176 to 0.399
IC Engine-R	**70%**	**28.72%**	**0.200 to 0.362**
Metered	90%	0.45%	0.191 to 0.193
Estimated	70%	56.45%	0.220 to 0.790
MT-N	**70%**	**17.28%**	**0.248 to 0.351**
Metered	90%	0.25%	0.306 to 0.308
Estimated	70%	69.54%	0.085 to 0.474
MT-R	**70%**	**44.86%**	**0.091 to 0.240**
Metered	90%	0.45%	0.145 to 0.146
Estimated	70%	100.0%	0.000 to 0.400

Table D-15: Uncertainty Analysis Results for Peak Demand Impact Results by Technology, Fuel, and Basis for SCG

Technology & Fuel / Basis	Confidence Level	Precision	Confidence Interval
FC-N	**90%**	**0.19%**	**0.567 to 0.569**
Metered	90%	0.17%	0.567 to 0.569
Estimated	70%	100.0%	0.000 to 0.900
FC-R	**90%**	**0.34%**	**0.231 to 0.233**
Metered	90%	0.34%	0.231 to 0.233
Estimated	N/A	N/A	N/A
GT-N	**70%**	**1.70%**	**0.868 to 0.898**
Metered	90%	0.28%	0.891 to 0.897
Estimated	70%	5.88%	0.800 to 0.900
IC Engine-N	**70%**	**10.51%**	**0.268 to 0.331**
Metered	90%	0.17%	0.312 to 0.313
Estimated	70%	33.09%	0.184 to 0.366
IC Engine-R	**70%**	**36.54%**	**0.391 to 0.841**
Metered	90%	0.45%	0.849 to 0.857
Estimated	70%	81.33%	0.086 to 0.835
MT-N	**70%**	**8.41%**	**0.210 to 0.249**
Metered	90%	0.22%	0.222 to 0.223
Estimated	N/A	N/A	N/A