BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Policies Procedures and Rules for the California Solar Initiative, the Self-Generation Incentive Program and Other Distributed Generation Issues.	Rulemaking 12-11-005 (File November 8, 2012)

SELF-GENERATION INCENTIVE PROGRAM SEMIANNUAL RENEWABLE FUEL USE REPORT NO. 22 FOR THE SIX-MONTH PERIOD ENDING JUNE 30, 2013

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February 27, 2014

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Pacific Gas and Electric Company (PG&E), on behalf of the Program Administrators[1/] for the Self Generation Incentive Program (SGIP), hereby files the Twenty Second Semi-Annual Renewable Fuel Use Report for completed SGIP projects that utilize renewable fuels, in compliance with California Public Utilities Commission (CPUC) Decision (D.) 02-09-051.[2/] By letter dated January 6, 2014 CPUC Executive Director Paul Clanon granted an extension until February 28, 2014 for the filing of this report.

This report provides the Energy Division of the CPUC with the required updated renewable fuel use information on completed SGIP projects using renewable fuel and helps assist the Energy Division in making recommendations concerning modifications to the

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1/ The SGIP Program Administrators include PG&E, Southern California Edison Company, Southern California Gas Company, and the California Center for Sustainable Energy in San Diego Gas & Electric Company's service territory.

2/ D.02-09-051, September 19, 2002.

renewable project aspects of the SGIP. Due to the ongoing interest in the potential for renewable fuel use projects to reduce greenhouse gas (GHG) emissions, the report also includes a section on GHG emission impacts from renewable fuel SGIP projects.

Respectfully submitted,

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Self-Generation Incentive Program Semi-Annual Renewable Fuel Use Report No. 22 for the Six-Month Period Ending June 30, 2013

1. Overview

Report Purpose

This report fulfills Decision 02-09-051 (September 19, 2002) of the California Public Utilities Commission (CPUC). That decision requires Self-Generation Incentive Program [1] (SGIP or Program) Program Administrators (PAs) to provide updated information every six months [2] on completed SGIP projects using renewable fuel. [3] The purpose of these Renewable Fuel Use (RFU) reports is to provide the Energy Division of the CPUC with the required updated renewable fuel use information. The report specifically contains compliance determinations of Renewable Fuel Use facilities with renewable fuel use requirements. In addition, the reports help assist the Energy Division in making recommendations concerning modifications to the renewable project aspects of the SGIP. Traditionally, these reports have included updated information on project fuel use and installed costs.

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[1] The SGIP provides incentives to eligible utility customers for the installation of new qualifying technologies that are installed to meet all or a portion of the electric energy needs of a facility. The program is implemented by the CPUC and administered by Pacific Gas and Electric Company (PG&E), Southern California Edison (SCE) and Southern California Gas Company (SCG) in their respective territories, and the California Center for Sustainable Energy (CCSE) in San Diego Gas and Electric (SDG&E) territory.

[2] Ordering Paragraph 7 of Decision 02-09-051 states:

"Program administrators for the self-generation program or their consultants shall conduct on-site inspections of projects that utilize renewable fuels to monitor compliance with the renewable fuel provisions once the projects are operational. They shall file fuel-use monitoring information every six months in the form of a report to the Commission, until further order by the Commission or Assigned Commissioner. The reports shall include a cost comparison between Level 3 and 3-R projects…."

Ordering Paragraph 9 of Decision 02-09-051 states:

"Program administrators shall file the first on-site monitoring report on fuel-use within six months of the effective date of this decision [September 19, 2002], and every six months thereafter until further notice by the Commission or Assigned Commissioner."

[3] The Decision defines renewable fuels as wind, solar, biomass, digester gas, and landfill gas. Renewable fuel use in the context of this report effectively refers to biogas fuels obtained from landfills, wastewater treatment plants, food processing facilities, and dairy anaerobic digesters.

Due to a growing interest in the potential for renewable fuel use projects to reduce greenhouse gas (GHG) emissions,[4] a section on GHG emission impacts from renewable fuel SGIP projects was added to the reports beginning with RFU Report No. 15.

RFU Report No. 22 covers projects completed during the six month period from January 1, 2013 to June 30, 2013, as well as all renewable fuel use projects installed previously under the SGIP since the Program's inception in 2001. Results of analysis of renewable fuel use compliance presented in this RFU Report are based on the 12 months of operation from July 1, 2012, to June 30, 2013.

RFU and RFUR Projects

The incentives and requirements for SGIP projects utilizing renewable fuel have varied throughout the life of the SGIP. In this report, assessment of compliance with the Program's minimum renewable fuel use requirements is restricted to the subset of projects actually subject to those requirements (i.e., Renewable Fuel Use Requirement (RFUR) projects) by virtue of their participation year, project type designation, and warranty status.[5] However, the analysis of project costs included in this report covers all projects using some renewable fuel (i.e., Renewable Fuel Use (RFU) projects). All RFUR projects are also RFU projects; however, not all RFU projects are RFUR projects. This distinction is responsible for differences in project counts in this report's tables. Differences between RFU and RFUR projects are summarized in Table 1. Similarly, Table 2 reports only on RFUR projects whereas Table 21 lists all RFU projects, including those not subject to the Program's minimum renewable fuel use requirements ("Other RFU projects").

4 While the SGIP was initially implemented in response to AB 970 (Ducheny, chaptered 09/07/00) primarily to reduce demand for electricity, SB 412 (Kehoe, chaptered 10/11/09) limits the eligibility for incentives pursuant to the SGIP to distributed energy resources that the CPUC, in consultation with the California Air Resources Board (CARB), determines will achieve reduction of greenhouse gas emissions pursuant to the California Global Warming Solutions Act of 2006.

5 The SGIP requires such projects to limit use of non-renewable fuel to 25 percent on an annual fuel energy input basis. This requirement is based on FERC definitions of qualifying small power production facilities from the original Public Utility Regulatory Policy Act (PURPA) of 1978; Subpart B; section 292.204 (Criteria for qualifying small power production facilities).

Table 1: Summary of RFU vs. RFUR Differences

Parameter	RFU	
	Other RFU[6,7]	RFUR
Allowed Level of Annual Renewable Fuel Use	0 – 100%	75% - 100%
Heat Recovery	Required	Not Required
Incentive Level	Same as non-renewable projects	Higher than non-renewable projects
No. of Projects	8	121
Rebated Capacity (MW)	3.8	60.5

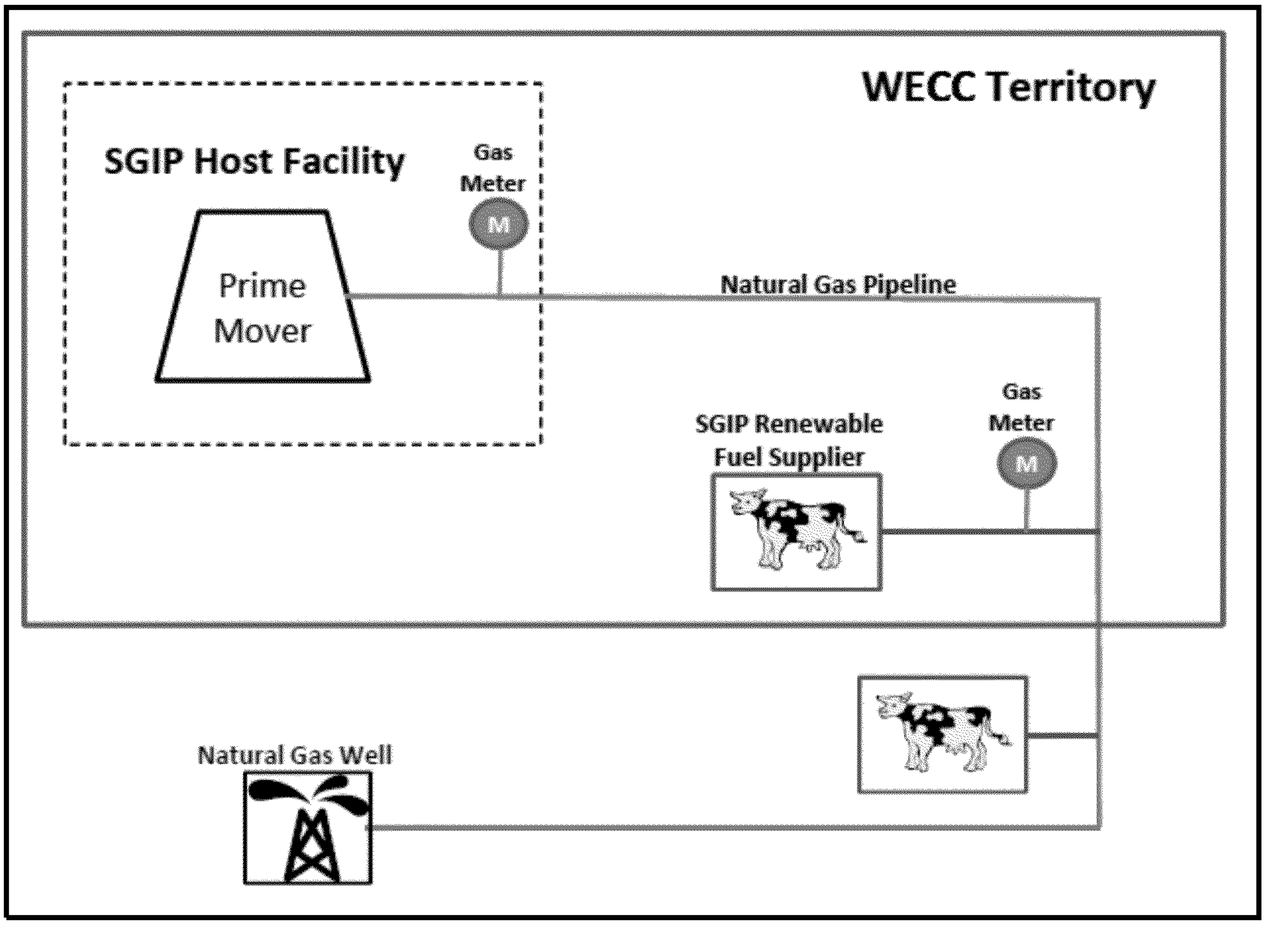
Directed Biogas Projects

In CPUC Decision 09-09-048 (September 24, 2009), eligibility for RFUR incentives was expanded to include "directed biogas" projects. Directed biogas projects purchase biogas fuel that is produced at another location than the project site. The procured biogas is processed, cleaned-up, and injected into a natural gas pipeline for distribution. Although the purchased biogas is not likely to be delivered and used at the SGIP renewable fuel project, the SGIP is credited with the overall use of biogas resources. Deemed to be renewable fuel use projects, directed biogas projects are eligible for higher incentives under the SGIP, and subject to the fuel use requirements of RFUR projects. The relative positions of key parties to directed biogas transactions are depicted graphically in Figure 1.

[6] The number of "Other" RFU projects increased from eight to nine in RFU Report No. 19 due to the completion of SCE project PY10-003. This project was completed in December 2010 but was not included in RFU Reports Nos. 17 and 18. The project was initially listed as non-renewable only but examination of metered data revealed the presence of renewable fuel.

[7] The number of "Other" RFU projects decreased from nine to eight in RFU Report No. 21 due to the completion of SCE project SCE-SGIP-2011-0334. This project was completed in November 2012 as a change for SCE project PY10-003 from level 3 to level 2. To properly account for this project's change in level, SCE project PY10-003 was removed from this report.

Figure 1: Schematic Depiction of Directed Biogas Arrangement



RFU Report No. 17 marked the first appearance of completed directed biogas projects under the SGIP. Each project is equipped with an on-site supply of utility-delivered natural gas. As such, the directed biogas is not literally delivered, but notionally delivered, as the biogas may actually be utilized at any other location along the pipeline route. Fifty-five directed biogas projects have been operational for at least one full calendar year and therefore are required to be in compliance with renewable fuel use requirements.

A description of the compliance determination methodology for dual-fueled and directed biogas projects is provided later in this report.

Summary of RFU Report No. 22 Findings

The following bullets represent a summary of key findings from this report:

- As of June 30, 2013, there were 129 RFU facilities deployed under the SGIP, representing approximately 64.3 megawatts (MW) of rebated capacity. One hundred and twenty one of these facilities were RFUR projects and represented approximately 60.5 MW of rebated capacity. The remaining eight Other RFU projects represented approximately 3.8 MW of rebated capacity.

- RFU Report No. 22 marks the sixth appearance of completed SGIP projects utilizing directed biogas. All four RFUR projects added during the first half of 2013 were all-electric fuel cells powered by natural gas.
- Of the 121 RFUR projects, 38 (about 31 percent) operated solely from on-site renewable fuels and as such inherently comply with renewable fuel use requirements. Of the remaining 83 dual-fuel RFUR facilities:
  - Three on-site blended RFUR projects were found to be in compliance with renewable fuel use requirements,
  - Thirty-four directed biogas projects were found to be in compliance with renewable fuel use requirements based on the audit methodology described in this report,
  - Twenty-one directed biogas projects could not have their compliance determined due to a lack of sufficient information upon which to make a compliance determination,
  - Nine projects were out of contract and as such were no longer subject to reporting and compliance requirements,
  - Twelve projects were found to be not applicable with respect to the requirements as they have not yet been operational for a full year, and
  - Four blended RFUR projects were found to be out of compliance.
- Of the twelve facilities not yet applicable with respect to the renewable fuel use requirements, nine were directed biogas systems.
- RFU facilities are powered by a variety of renewable fuel (i.e., biogas) resources. However, approximately 49 percent of the rebated capacity of RFU facilities deployed through June 30, 2013 were powered by directed biogas.
- Prime movers used at RFU facilities include fuel cells, microturbines, and internal combustion (IC) engines. Historically, IC engines have been the dominant prime mover technology of choice at RFU facilities. With the emergence of directed biogas as an eligible renewable fuel, IC engines have as of this reporting period been surpassed by all-electric fuel cells as the dominant prime mover technology. All-electric fuel cells provide approximately 31.6 MW (about 49 percent) of the approximately 64.3 MW of rebated RFU capacity. IC engines provided 15.7 MW (about 24 percent of all RFU capacity).
- Based on samples of costs of RFU facilities, the average costs of renewable projects appeared to be higher than the average costs of non-renewable projects. However, limited and highly variable cost data prevent the conclusion that there is a 90 percent certainty that the mean cost of renewable-powered CHP fuel cells and IC engines is higher than the mean cost of CHP fuel cells and IC engines powered by non-renewable

resources. In the case of CHP fuel cells, other factors such as system size and fuel cell chemistry confound the comparison.

- RFU facilities have considerable potential for reducing GHG emissions. The magnitude of the GHG emission reduction depends largely on the manner in which the biogas would have been treated in the absence of the program (i.e., the "baseline" condition). RFU facilities that would have been venting biogas directly to the atmosphere have a much higher GHG emission reduction potential than RFU facilities that would have been required to capture and flare biogas.[8]
  - In general, RFU facilities for which biogas flaring was the baseline condition decreased GHG emissions by around 0.35-0.50 tons of carbon dioxide equivalent (CO_2eq) per megawatt-hour (MWh) of generated electricity.
  - The GHG emission reduction potential of RFU facilities for which biogas venting was the baseline condition is around 4.6 tons of CO_2(eq) per MWh of generated electricity; an order of magnitude greater in GHG emission reduction potential.
- Potential for GHG emission reductions from RFU facilities may also be affected by the use of waste heat recovery at the RFU facility. In general, RFU facilities that use waste heat recovery increase the potential for GHG emission reduction if natural gas would otherwise have been used to generate process heat.

Conclusions and Recommendations

In accordance with the original 02-09-051 CPUC decision in September 2002, the overall purpose of the renewable fuel use reports is to help ensure that projects receiving increased incentives for being renewably fueled are in fact meeting the renewable fuel use requirements. Renewable Fuel Use Report No. 22 marks the eighth consecutive occurrence of non-compliance with renewable fuel use requirements. While some of these instances of non-compliance are due to projects occasionally falling below the minimum renewable fuel limit, some projects are consistently out of compliance. While we are able to make determinations on compliance of the projects, it was beyond the scope of the RFU Report to investigate reasons why the projects failed to comply. As a result, we cannot explain why these on-site biogas projects are out of compliance and if they are capable of meeting the requirements in the future.

This report also marks the first instance where directed biogas audit protocols developed by the PAs and their consultant Alternative Energy Systems Consulting (AESC) were used to make compliance determinations. This report found that 34 directed biogas projects were in

[8] Biogas which is vented to the atmosphere has a significant amount of methane. Methane is a very powerful GHG compound with approximately 21 times the GHG impact of CO_2.

compliance with renewable fuel use requirements but it also includes 21 instances where we were unable to make compliance determinations because data and supporting documentation were not provided in a timely manner.

Finally, in accordance with CPUC decision 02-09-051, this report includes information on project installed costs. Comparison of the installed costs between renewable- and non-renewable fueled generation systems reveals that average non-renewable generator costs have typically been lower than average renewable fueled generator costs. However, confidence intervals calculated for populations comprising both past and future SGIP participants are very large. In fact, these confidence intervals prevent drawing conclusions about cost differences in IC engine and CHP fuel cell projects; only microturbine projects exhibit cost differences at 90 percent confidence. This suggests that data for past projects should not be used as the sole basis for SGIP design elements affecting future participants. Updated costs for renewable fuel use systems will be obtained from the updated SGIP cost-effectiveness analysis report and will be used in future RFU reports.

In light of these conclusions, we make the following recommendations:

1) Conduct Further Studies on Projects Repeatedly Out of Compliance

In RFU Report No. 20 we recommended further investigation into the reasons why certain projects are consistently out of compliance with the SGIP standards. We continue to recommend that further study be conducted into projects that are consistently out of compliance as this information could potentially be useful to ensure higher levels of compliance in the future.

2) Require More Expeditious Delivery of Directed Biogas Data

As indicated earlier, approximately 30 percent of the RFUR projects assessed in RFU Report No. 22 were directed biogas projects that lacked sufficient information upon which to assess compliance. Historically, compliance determinations for directed biogas projects have been constrained by a lack of established protocols, errors and omissions in biogas documentation, and pre-established methods for resolving discrepancies in said documentation. The PAs have made significant progress in resolving these issues by establishing clear protocols that govern the process for auditing SGIP directed biogas procurement. Having said that, we find that the timely delivery of directed biogas documentation from the relevant parties to the evaluation contractor remains a weak link in the process. To resolve these issues, we recommend that the directed biogas audit protocols be expanded to include timeframes for expeditious delivery of the data and documentation needed to make compliance findings. The established timeframes should provide clear and specific deadlines for each of the parties involved in providing the necessary information and be based on deadlines associated with filing of the RFU reports.

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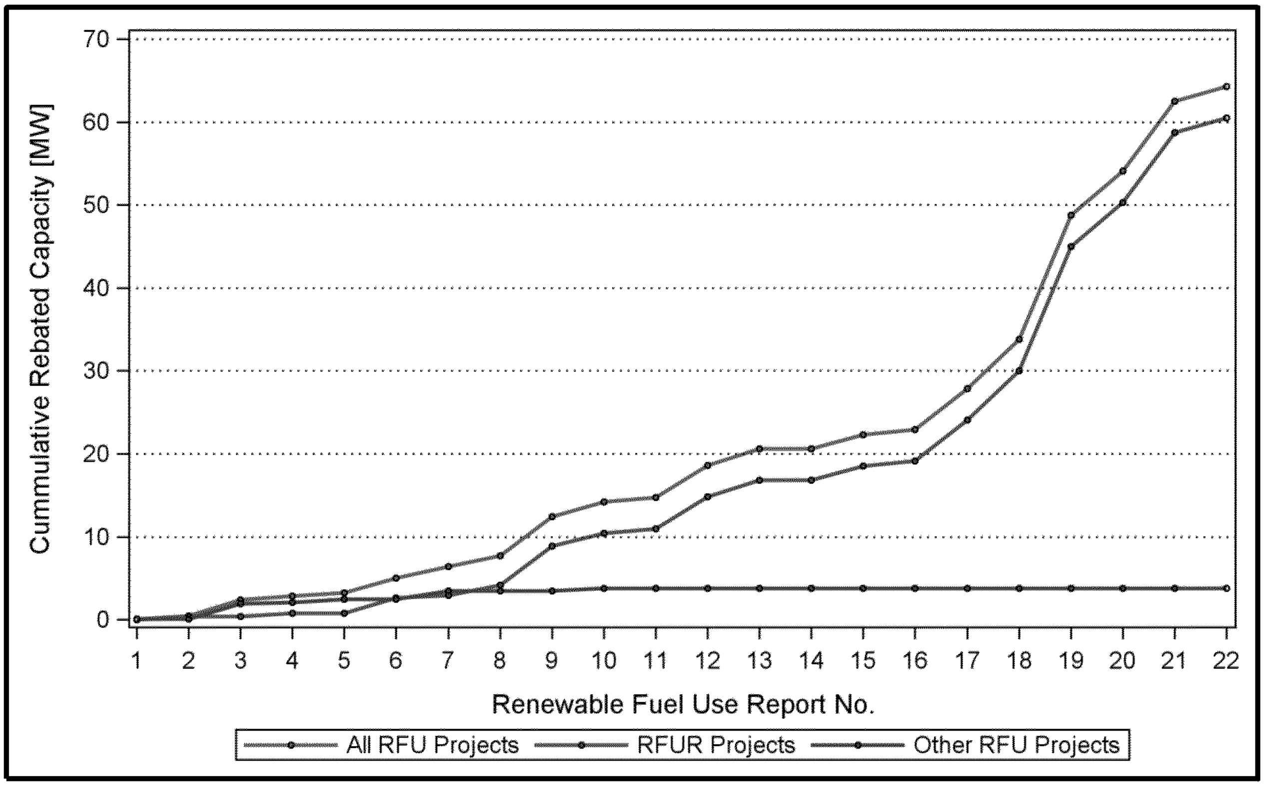
2. Project Capacity, Fuel Types, and Prime Mover Technology

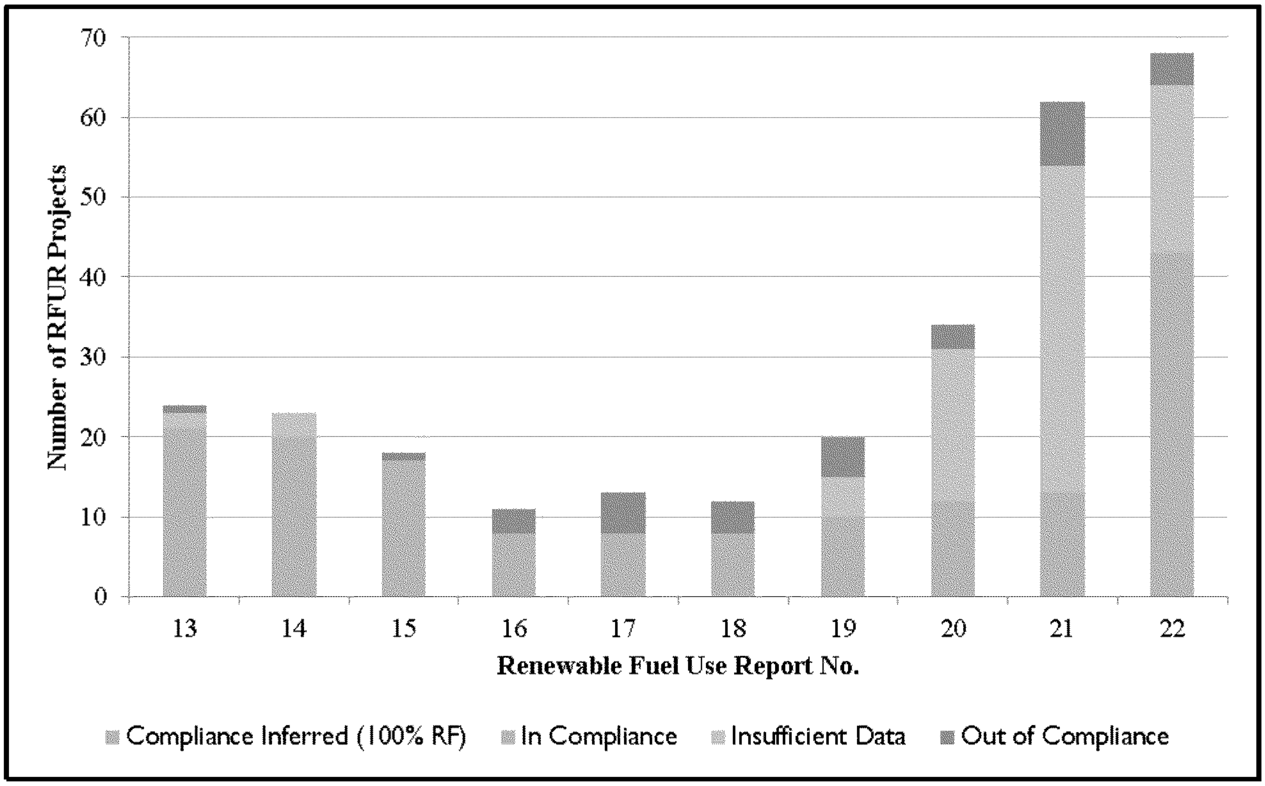
The capacity of RFUR and Other RFU projects, and the combined total (RFU projects) covered by each RFU report is depicted graphically in Figure 2.

Figure 2: Project Capacity Trend (RFU Reports 1–22)



While all RFUR projects are allowed to use as much as 25 percent non-renewable fuel, 31 percent (by project count) of RFUR projects operate completely from on-site renewable fuel resources. Up to and including RFU Report No. 12, there had been no instances where available data indicated non-compliance with the Program's renewable fuel use requirements. However, note that prior to RFU Report No. 13 some data were not available to evaluate compliance of all dual-fuel projects. The current report contains four instances of non-compliance with these requirements. Figure 3 shows the history of compliance back to RFU Report No. 13 for all projects that were subject to the renewable fuel use requirement when the respective report was written.

Figure 3: RFUR Project Compliance History



* This figure contains information limited to systems that are subject to the renewable fuel use requirement – RFUR projects under warranty and operational for at least one calendar year during each RFU report's specific reporting period (68 projects in RFU Report # 22). Other systems are excluded from this figure.

RFU projects typically use biogas derived from landfills or anaerobic digestion processes that convert biological matter to a renewable fuel source. Anaerobic digesters are used at dairies, wastewater treatment plants, or food processing facilities to convert wastes from these facilities to biogas. Figure 4 shows a breakout of RFU p rojects as of June 30, 2013, by source of biogas (e.g., landfill gas, dairy digester gas, food processing digester gas) on a rebated capacity basis . The majority of biogas used in SGIP RFU projects is delivered as directed biogas . Dairy digesters provide the smallest contribution at two percent of the total rebated RFU project capacity.

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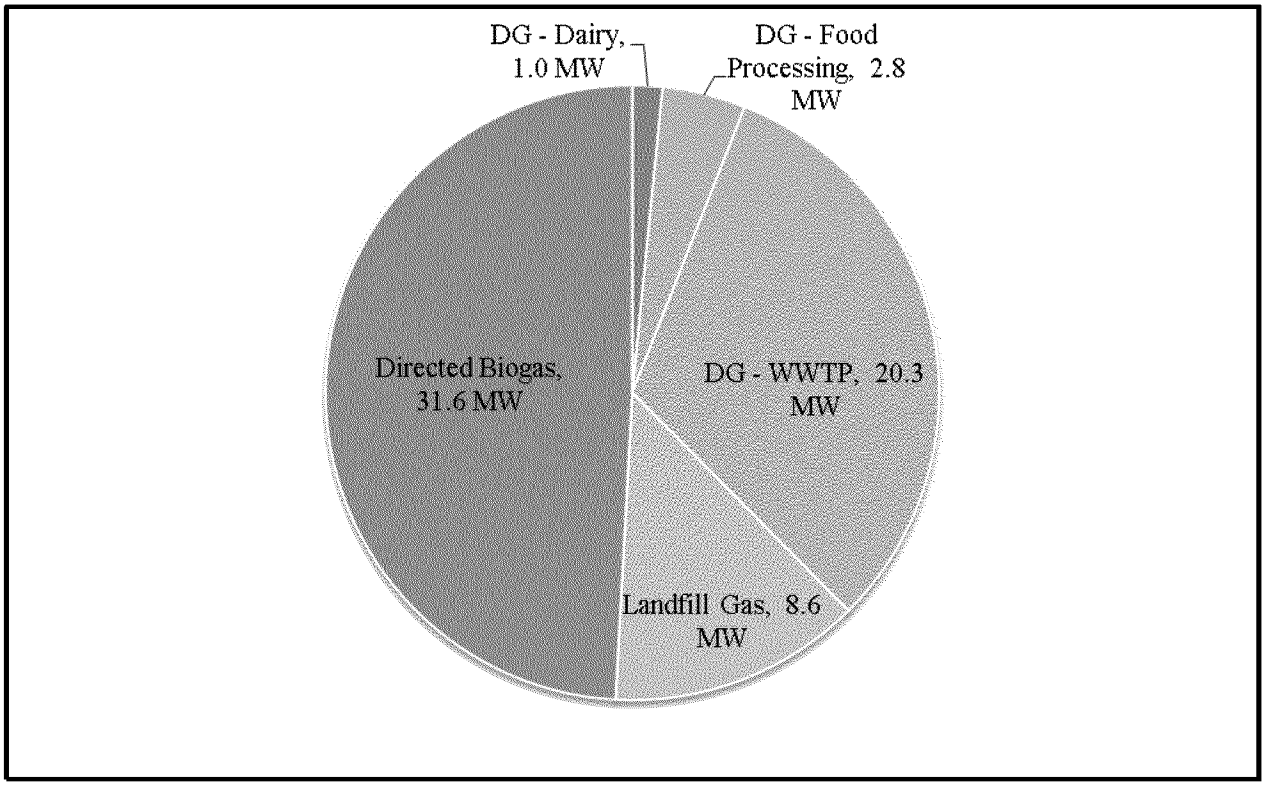
Figure 4: Renewable Fuel Use Project Rebated Capacity by Fuel Type



DG=digester gas; WWTP = wastewater treatment plants

Figure 5 provides a breakdown of the relative contribution of the different biogas fuels by prime mover technology. All-electric fuel cells are the dominant technology with 49 percent of rebated capacity. RFU Report No. 22 marks the sixth appearance of directed biogas projects installed under the SGIP; all of these projects are all-electric fuel cells.

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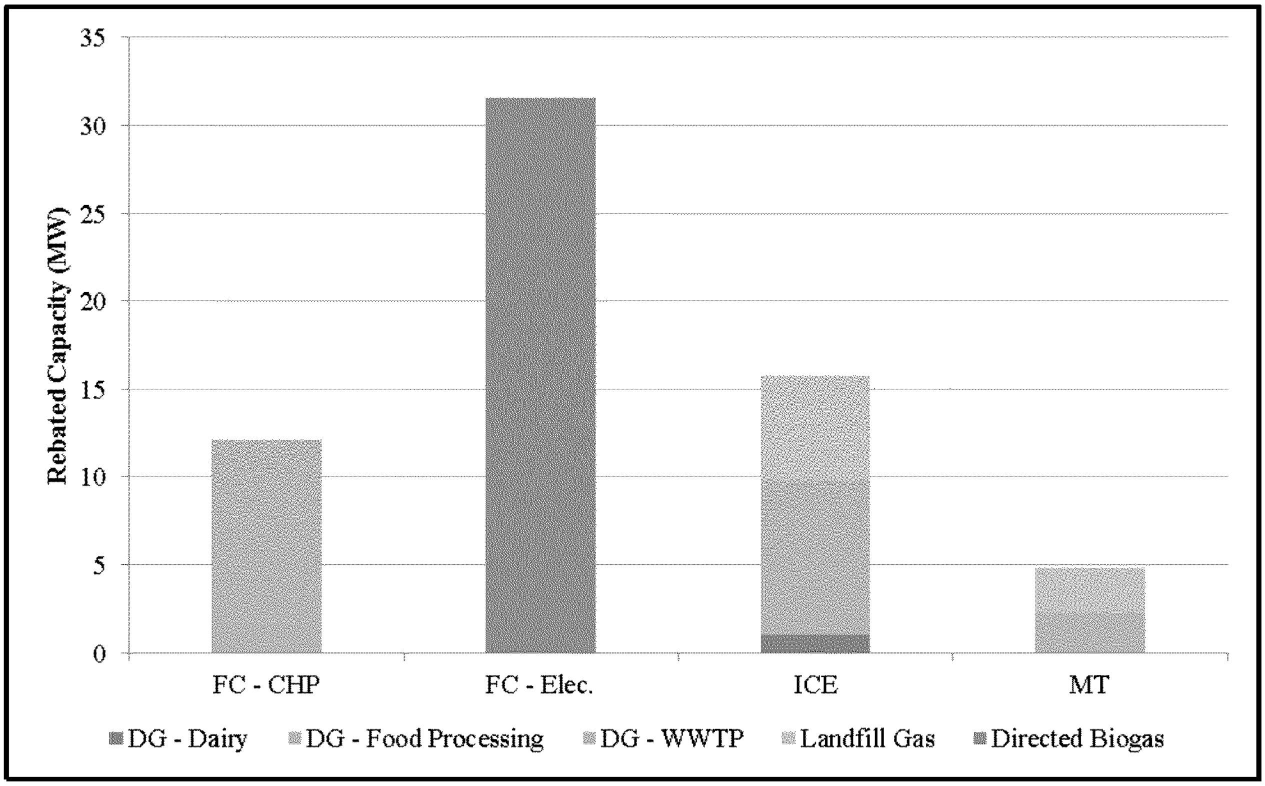
Figure 5: Contribution of Biogas Fuel Type by Prime Mover Technology



WWTP = wastewater treatment plants; MT = microturbines; ICE = internal combustion engine ; FC – CHP = CHP fuel cells; FC – Elec. = Electric-only fuel cells; DG = digester gas

Cost Data

Itron also analyzed project cost data available for the renewable and non -renewable SGIP projects completed to d ate. Average costs of renewable projects were higher than the average costs of non-renewable projects . H owever, the combined influence of relatively small sample sizes and substantial variability preclude us from estimating incremental costs for future SGIP participants that are accurate enough to be used directly for program incentive design purposes.

Confidence intervals estimated for the entire population of SGIP participants (both past and future) are very large. There was a limited quantity of cos t data for fuel cells and IC engines. This limited amount of data increases the uncertainty associated with estimates of population mean costs of fuel cells and IC engines. As a result, it is impossible to say with 90 percent confidence that the population mean costs of renewable IC engines and fuel cells are any higher than the population mean costs of non -renewable IC engines and fuel cells. This lack of confidence suggests that data for past projects should not be used as the sole basis for SGIP design elements affecting future participants. Engineering estimates, budget cost data, and rules - of-thumb likely continue to be more suitable for this purpose at this time. As noted earlier, updated renewable fuel system costs are to be obtained in the forthcoming SGIP cost-effectiveness analysis report and will be used in future RFU reports once available.

3. Summary of Completed RFUR Projects

There were four new RFUR SGIP projects completed during the subject six-month reporting period. All of the recently completed projects were electric-only directed biogas fuel cells ranging in size from 105 kW to 1,050 kW. A total of 121 RFUR projects had been completed as of June 30, 2013. A list of all SGIP projects utilizing renewable fuel (RFUR and Other RFU) is included as Appendix A.

The 121 completed RFUR projects represent approximately 60.5 MW of rebated generating capacity. The prime mover technologies used by these projects are summarized in Table 2. Fuel cells alone accounted for almost 71 percent of RFUR rebated capacity, with IC engines and microturbines making up the remaining 29 percent. The average sizes of fuel cell and IC engine projects are two to three times those of microturbine projects.

Table 2: Summary of Prime Movers for RFUR Projects

Prime Mover	Num. of Projects	Total Rebated Capacity (kW)	Average Rebated Capacity Per Project (kW)*
FC – CHP	14	11,100	793
FC – Elec.	64	31,570	493
ICE	24	13,846	577
MT	19	3,970	209
Total	**121**	**60,486**	**500**

FC - CHP = CHP fuel cell; FC – Elec. = electric-only fuel cell; MT = microturbine; ICE = internal combustion engine
* Represents an arithmetic average

Many of the RFUR projects recover waste heat even though they are exempt from heat recovery requirements. Waste heat recovery incidence by renewable fuel type is summarized in Table 3. Verification inspection reports obtained from PAs and information from secondary sources such as direct contact with the participant, technical journals, industry periodicals, and news articles indicate that 38 of the 121 RFUR projects recover waste heat. All but six of the 42 on-site digester gas systems include waste heat recovery.[9] Waste heat recovered from digester gas systems is generally used to pre-heat waste water sludge prior to being pumped to digester tanks.

[9] In several RFU reports up to and including RFU Report No. 15 three (3) projects were incorrectly reported as not including heat recovery. This error resulted from misinterpretation of contents of Installation Verification Inspection Reports.

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Conversely, 2 of 15 on-site landfill gas systems include waste heat recovery. In addition, those landfill gas systems that do recover heat do not use it directly at the landfill site. Instead, the landfill gas is piped to an adjacent site that has both electric and thermal loads, and the gas is used in a prime mover at that site.[10] None of the 64 completed directed biogas projects include waste heat recovery as they are all-electric fuel cells.

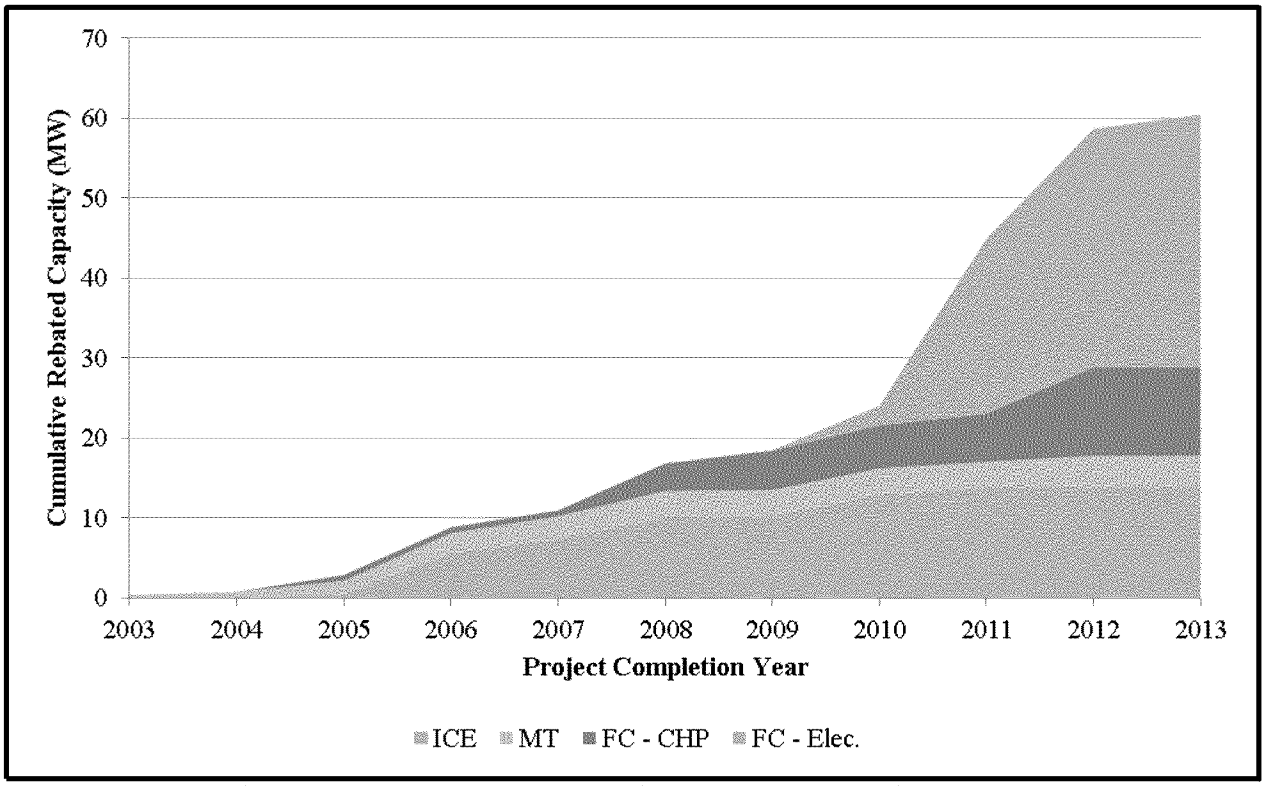
Table 3: Summary of Waste Heat Recovery Incidence by Type of Renewable Fuel for RFUR Projects

Renewable Fuel Type	Total No. of Sites	Sites With Heat Recovery	Sites Without Heat Recovery
Digester Gas (On-Site)	42	36	6
Landfill Gas (On-Site)	15	2	13
Directed Biogas	64	0	64
Total	**121**	**38**	**83**

Figure 6 shows the cumulative RFUR capacity for each year by technology. Calendar year 2006 saw the largest growth in IC engine RFUR capacity. All-electric fuel cells were by far the most common RFUR projects introduced in 2011 and 2012 with over 27 MW of rebated capacity completed in both years.

10 In general, above-ground digesters have a built-in thermal load as they operate better if heated. Landfill gas and covered lagoon operations do not typically use recovered waste heat to increase the rate of the anaerobic digestion process.

Figure 6: Cumulative Rebated RFUR Capacity by Technology and Project Completion Year



FC - CHP = CHP fuel cell; FC – Elec. = electric-only fuel cell; MT = microturbine; ICE = internal combustion engine

4. Fuel Use at RFUR Projects

RFUR projects are allowed to use a maximum of 25 percent non-renewable fuel; the remaining 75-100 percent must be renewable fuel. The period during which RFUR projects are obliged to comply with this requirement is specified in the SGIP contracts between the host customer, the system owner, and the PAs. Specifically, this compliance period is the same as the equipment warranty requirement. For PY01-PY11 applications, microturbine and IC engine systems must be covered by a warranty of not less than three years. Fuel cell systems must be covered by a minimum five-year warranty. For PY12 and PY13 projects, all generation systems must have a minimum 10 year warranty. Therefore, the fuel use requirement period is three, five, or ten years, depending on the technology type and program year. The SGIP applicant must provide warranty (and/or maintenance contract) start and end dates in the Reservation Confirmation and Incentive Claim Form.

Facilities are grouped into three categories in assessing renewable fuel use compliance:

- "Dedicated" RFU facilities located where biogas is produced (e.g., wastewater treatment facilities, landfill gas recovery operations) and the biogas is the only fuel source for the prime mover;
- "Blended" RFU facilities located where biogas is produced that use a blend of biogas and non-renewable fuel (e.g., natural gas); and
- "Directed" RFU facilities, located somewhere other than where biogas is produced and not necessarily directly receiving any of the biogas.

Fuel supply and contract status for RFUR projects are summarized in Table 5. Eighty of the total 121 RFUR projects had active warranty status. Forty-one RFUR projects (over one-third of all RFUR projects) had an expired warranty status. Of the 80 RFUR projects with active warranties, six operated solely on renewable fuel. By definition, all six of those RFUR projects are in compliance with SGIP renewable fuel use requirements.

Table 4: Summary of Fuel Supplies and Warranty Status for RFUR Projects

Fuel Supply	Warranty/Renewable Fuel Use Requirement Status					
	Active		Expired		Total	
	No. Projects (n)	Rebated Capacity (kW)	No. Projects (n)	Rebated Capacity (kW)	No. Projects (n)	Rebated Capacity (kW)
Renewable only	6	3,630	32	11,598	38	15,228
Non-Renewable & On-Site Renewable	10	8,850	9	4,838	19	13,688
Non-Renewable & Off-Site, Directed Renewable	64	31,570	-	-	64	31,570
Total	**80**	**44,050**	**41**	**16,436**	**121**	**60,486**

Information on fuel use for the remaining 74 blended renewable and directed biogas projects with active warranties is presented below.

Fuel Use at Blended RFUR Projects

For blended RFUR facilities using both on-site renewable and non-renewable fuel, assessing compliance requires information on the amount of biogas consumed relative to the amount of non-renewable fuel consumed on-site. Most blended RFUR projects are equipped with a dedicated natural gas meter that measures the amount of non-renewable fuel being consumed by the project. Meters indicating the amount of renewable fuel being consumed by the SGIP project are owned and maintained by other program participants like system owners or host customers.

Historically, metered data obtained from these renewable fuel meters have proven unreliable due to uncertainty regarding the energy content of the fuel and general difficulties that arise when relying on third parties to develop, operate, and maintain data collection systems satisfying the accuracy and reliability requirements of program impacts evaluation.

In order to make a renewable fuel use compliance determination without metered on-site biogas data, it is necessary to estimate the total energy input (renewable + non-renewable fuel) of SGIP projects. The total energy input of SGIP projects is estimated by dividing the electrical generation of the project by an assumed electrical conversion efficiency.[11] The estimate of renewable fuel consumption is then calculated as the difference between the estimate of total energy input and the metered non-renewable fuel consumption.

Blended RFUR Projects in Compliance

During this reporting period three blended RFUR projects were found to be in compliance with SGIP renewable fuel use requirements.

- **SCG 2006-036.** This 1,200 kW fuel cell system came on-line in October 2008. The system is located at a wastewater treatment facility and utilizes renewable fuel produced by a digester system. The project was offline and did not consume any fuel during the entire reporting period and therefore is found to be in compliance with SGIP renewable fuel use provisions.
- **SCE PY10-002.** This project is a 750 kW fuel cell system consisting of three 250 kW stacks, of which only two are rebated as dual fueled systems under this application number. The system is located at a waste water treatment plant and at the time of the SCE installation verification inspection was capable of producing sufficient anaerobic digester gas (ADG) to run two of the units using 100% ADG. Itron assumed an electrical conversion efficiency of 26 percent to estimate total fuel use during periods of electricity generation. Based on these estimates, the renewable fuel usage during the current reporting period exceeded 82 percent of the total annual fuel input. The system was found to be in compliance with SGIP renewable fuel use provisions for this reporting period.
- **CCSE 0362-09.** This 300 kW fuel cell utilizes a blend of digester gas from a waste water treatment plant and natural gas. The system became operational in December 2011 and is therefore required to comply with SGIP renewable fuel use requirements. When sufficient digester gas is not available to run this system at full load, natural gas is mixed

[11] In these calculations an electrical conversion efficiency of 26 percent was assumed. The intent was to develop an efficiency likely to be lower than the actual efficiency. If the actual efficiency is higher than 26 percent (which is likely), then the actual non-renewable fuel use is higher than the estimated percent. The basis of this efficiency estimate is the lowest annual electrical conversion efficiency observed among CHP fuel cells in 2012.

in. Itron assumed an electrical conversion efficiency of 26 percent to estimate total fuel use during periods of electricity generation. Based on the data provided, the renewable fuel usage during the reporting period exceeded 84 percent of the total energy consumed. The project was found to be in compliance with SGIP renewable fuel use provisions for this reporting period.

Blended RFUR Projects Not in Compliance

Four projects were found to be using more non-renewable fuel than allowed during this reporting period.

- **SCG 2008-003.** This 600 kW fuel cell project came on-line in December 2009 and consists of two 300 kW fuel cells. The system utilizes renewable fuel produced from onion feedstock and natural gas from SCG. At the time of the SCG installation verification inspection, the fuel cells were using a 21 percent natural gas and 79 percent renewable fuel mix. Itron assumed an electrical conversion efficiency of 26 percent to estimate total fuel use during periods of electricity generation. Based on these estimates, the renewable fuel usage during the current reporting period was less than 69 percent. The system was not in compliance with SGIP renewable fuel use provisions for this reporting period.
- **SCG 2006-012.** This 900 kW fuel cell project came on-line in December 2009 and consists of three 300 kW fuel cells. The system is located at a wastewater treatment facility and utilizes renewable fuel produced from two digesters and natural gas from SCG. These digesters are provided sewage sludge and fat, oil, and grease as feedstock. The fat, oil, and grease feedstock comes from local restaurants and is supplied by a vendor under a contractual agreement. No description of how or when natural gas is used by this system was included in SCG's installation verification inspection report. Itron assumed an electrical conversion efficiency of 26 percent to estimate total fuel use during periods of electricity generation. Based on these estimates, the renewable fuel usage during the current reporting period did not exceed 73 percent. The system was not in compliance with SGIP renewable fuel use provisions for this reporting period.
- **SCE PY09-003.** This 300 kW fuel cell is one of four systems installed at a water pollution control facility. The system utilizes a combination of waste water digester gas and natural gas. The system became operational in August 2011 and is therefore required to comply with SGIP renewable fuel use requirements. Itron assumed an electrical conversion efficiency of 26 percent to estimate total fuel use during periods of electricity generation. Based on these estimates, the renewable fuel usage during the current reporting period did not exceed 63 percent of the total annual fuel input. The system was not in compliance with SGIP renewable fuel use provisions for this reporting period.

- **SCE PY09-013.** This 600 kW fuel cell system came online in March 2012 and consists of two 300 kW fuel cells. The system is located at a water reclamation facility. ADG is produced by on-site anaerobic digesters. Supplemental natural gas is available when there is insufficient ADG to operate the fuel cells at full capacity. At the time of the SCE installation verification inspection, the system was operating on 100% ADG. Itron assumed an electrical conversion efficiency of 26 percent to estimate total fuel use during periods of electricity generation. Based on these estimates, the renewable fuel usage during the current reporting period did not exceed 58 percent of the total annual fuel input. The system was not in compliance with SGIP renewable fuel use provisions for this reporting period.

Dual-Fueled RFUR Project Compliance Status Not Yet Applicable

A blended RFUR project is assigned compliance status "Not Yet Applicable" if it has not yet been operational for a complete calendar year. There are three CHP fuel cell projects in this category.

Historically, a summary of projects and a compliance assessment was attempted for projects not yet operational for a complete calendar year. In this report, information about projects not yet subject to compliance determination requirements is presented exclusively in Table. Furthermore, as the number of projects no longer under warranty has grown over time, summary information about these projects will no longer be presented in this section.

A summary of the 10 blended RFUR projects with active warranties during this reporting period, including those lacking a full year's operational experience, is presented in Table 6.

Table 6: Fuel Use Compliance of Blended RFUR Projects

PA	SGIP Reservation Number	Incentive Level	Tech	Renewable Fuel Type	Capacity (kW)	Operational Date*	Annual Natural Gas Energy Flow (MMBtu) †	Renewable Fuel Use (% of Total Energy Input)	Meets Program Renewable Fuel Use Requirements?
SCG	2006-036	Level 2	FC	DG - WWTP	1,200	10/27/2008	0	NA	Yes
SCG	2008-003	Level 2	FC	DG – Food Processing	600	12/14/2009	17,420	68%	No
SCG	2006-012	Level 2	FC	DG – WWTP	900	12/18/2009	5,846	72%	No
SCE	PY10-002	Level 2	FC	DG – WWTP	500	10/31/2010	5,520	83%	Yes
SCE	PY09-003	Level 2	FC	DG - WWTP	300	8/30/2011	8,115	62%	No
CCSE	CCSE-0362-09	Level 2	FC	DG – WWTP	300	12/21/2011	2,318	85%	Yes
SCE	PY09-013	Level 2	FC	DG - WWTP	600	3/28/2012	23,343	58%	No
SCE	SCE-SGIP-2011-0334	Level 2	FC	DG – WWTP	250	11/9/2012	TBD	TBD	Not Yet Required
PG&E	1867	Level 2	FC	DG – WWTP	1,400	11/29/2012	TBD	TBD	Not Yet Required
SCG	2010-026	Level 2	FC	DG – WWTP	2,800	12/21/2012	TBD	TBD	Not Yet Required

* Since assignment of a project's operational date is subject to individual judgment, the incentive payment date as reported by the PAs is used as a proxy for the operational date for reporting purposes.

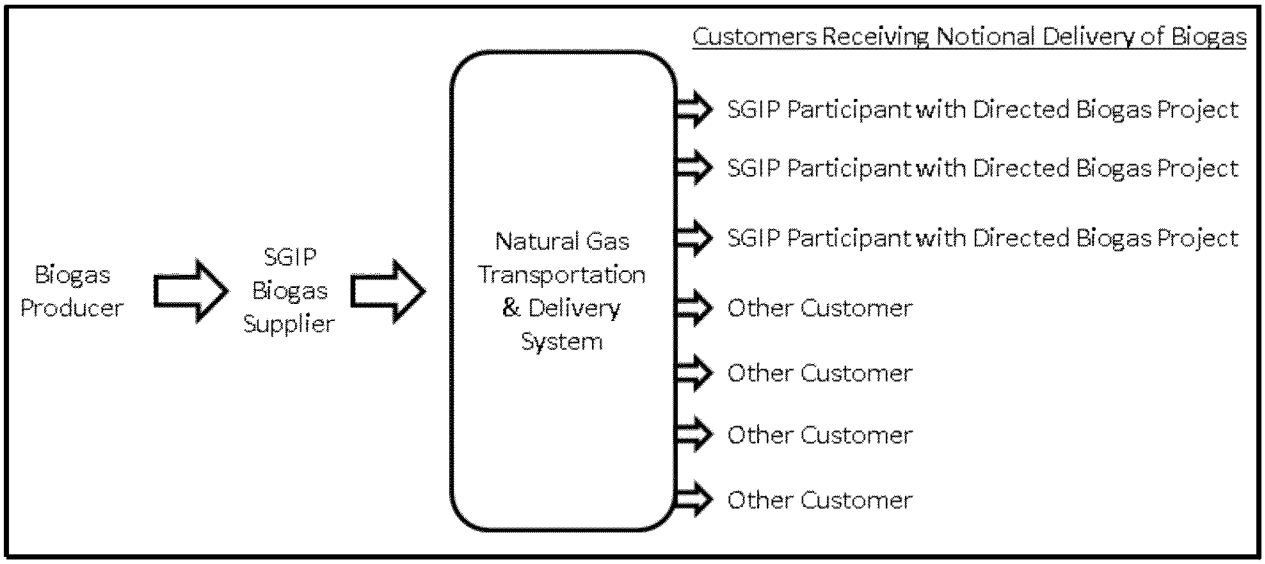
† This field represents the natural gas consumption during the 12-month period ending June 30, 2013. The basis is the lower heating value (LHV) of the fuel.

Directed Biogas Compliance Verification Methodology

It is not possible to use the same method in assessing compliance of directed biogas projects as that used for assessing compliance of blended RFUR projects. In blended RFUR projects using biogas produced on-site, the metered amount of non-renewable fuel is used to determine if it is less than or equal to 25 percent of the total annual energy input to the RFUR project. However, in directed biogas RFUR projects, metering of SGIP systems captures total fuel use only; it provides no information on how much biogas was actually produced and allocated to the project.

Assessing compliance of directed biogas projects requires information about off-site biogas production, transportation, and subsequent allocation to customers that may or may not be SGIP participants. The left side of Figure 7 depicts the injection of biogas into the natural gas transportation and delivery system. The right side depicts the extraction of natural gas from the system and allocation to specific customers. On an energy content basis injections and extractions depicted in Figure 7 must be in balance.

Figure 7: Parties to Notional Deliveries of Directed Biogas



Specification of the approach used to assess the balance of injections and extractions is dictated by the properties of transactions at the two points. These properties are summarized in Table 7. The properties at the extraction point represent a significant departure from conditions encountered to date for dedicated and blended RFU projects. Specifically, at the extraction point the transaction type is notional rather than physical, and information is obtained from invoices rather than metering. To assess the system's balance and thereby enable accurate assessment of the role of SGIP specifically in increasing overall biogas production and consumption, complete information for injections and extractions is required.

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Table 7: Properties of Directed Biogas Injection and Extraction

Property	At Injection	At Extraction
Carrier for renewable fuel	Biogas	Natural Gas
Transaction type	Physical	Notional
Information source	Metering	Invoices

The properties of directed biogas injection and extraction have a direct bearing on information needed to assess renewable fuel use compliance of directed biogas projects. On April 14, 2011, the SGIP PAs and their consultant AESC developed protocols for the audit of directed biogas usage. The audit protocol establishes data and verification requirements and is separated into three elements:

1) **Transfer of Ownership** – documentation and "linkage" demonstrating transfer of ownership of the directed biogas from source to one or more serial entities and then to the system owner.
2) **Transportation Path and Energy Accounting** – documentation reporting the amount (energy) of directed biogas from the eligible source to one or more serial pipelines and then to the System Owner. The documentation must report verifiable inputs and outputs of each pipeline segment. Imbalances, losses, and fees (paid in gas energy) must be included in the documented reports. Note that because directed biogas "accounting" is lost once it enters a gas distribution system, directed biogas can be notionally accounted for up to the gas utility receipt points (city gates). Note that "pooling" or carryover from unconsumed directed biogas is allowed.
3) **Gas Fuel Consumption** – documentation from the gas utility matching directed biogas receipts and reporting the metered total energy input to a SGIP eligible generator or fleet of SGIP eligible generators.

The data and documentation requirements for each element of the verification process as well as the limitations of the protocol are described in more detail below.

Transfer of Ownership

Acceptable documentation includes invoices or other statements showing transfer of ownership of biogas between the source and the SGIP system owner. If a broker, marketer, or scheduler takes ownership of the gas between the source and the system owner then intermediate documentation showing transfer of ownership is also required.

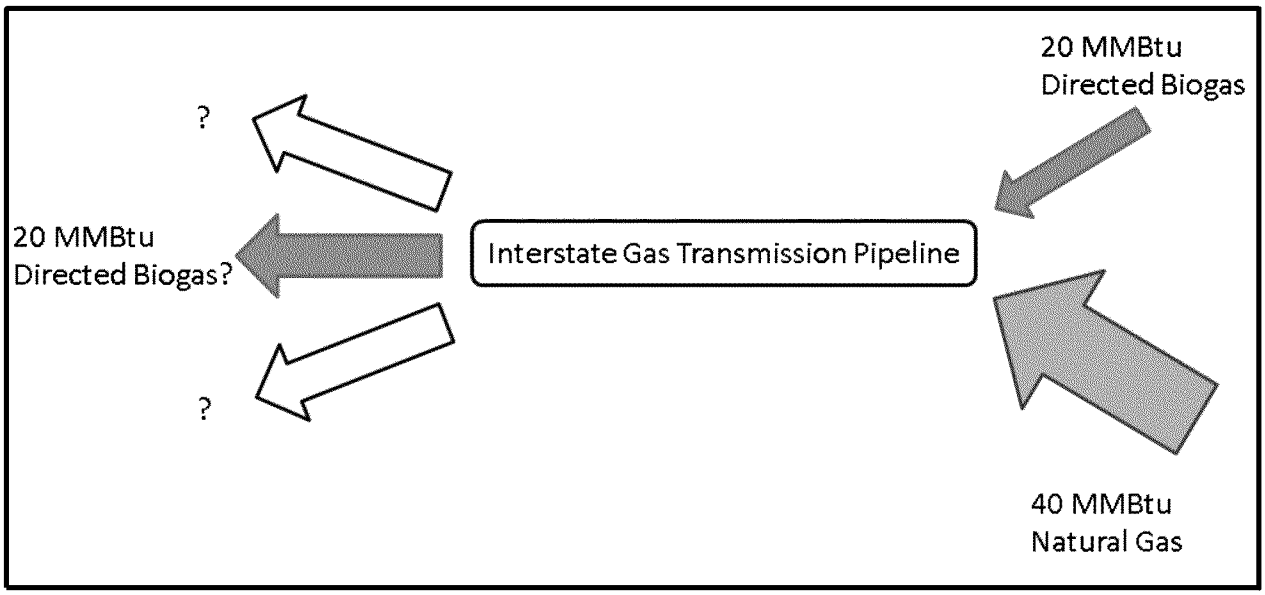
Transportation Path and Energy Accounting

Documentation from each entity in the transportation path must include:

- Documentation from the source showing the amount of directed biogas being moved onto the pipeline. Any non-renewable gas added at the source must be identified.
- Documentation from the gas transmission system showing:
  - Receipt of directed biogas (from source, storage, or other pipelines)
  - Pipeline losses or fees paid in gas (not carried over)
  - Positive or negative imbalances (carried over)
  - Delivery of directed biogas to either another pipeline, storage facility, or California utility receipt point
- Utility documentation showing the amount of biogas received at all California entry points
- Utility documentation showing the amount of fuel consumed by each SGIP project being supplied the directed biogas

As stated earlier, the transportation path and energy accounting is notional rather than physical. Figure 8 is a representative example of the types of issues encountered during verification of the transportation path.

Figure 8: Representative Example of Gas Transportation Accounting Issue



In Figure 8, a gas marketer enters into contract with an interstate gas transmission pipeline for the transport of 20 MMBtu of directed biogas and 40 MMBtu of non-renewable natural gas.

Assuming no fuel losses or imbalances, the same amount of gas exits the pipeline . Most interstate pipelines or gas hubs have various delivery points where gas can be delivered to. In some cases, the only information regarding directed biogas allocations is guidance from the gas marketer. In this sense, compliance determinations rely on accurate information provided by program participants.

A similar situation occurs with out of state physical storage. If a storage vessel contains both directed biogas and non-renewable natural gas, the green attributes of any withdrawal are completely up to the discretion of the gas marketer. In this sense, the verification process is not truly independent. A hypothetical scenario where a gas marketer sells the same green gas attributed to SGIP projects to another entity outside of California is possible. Compliance determinations made in this report rely on the good faith of documentation provided by gas marketers and renewable fuel supply affidavits submitted to the SGIP PAs.

The audit protocol stipulates that the gas transportation accounting ends at the California entry point (city gate) and does not continue inside the gas company's distribution system.

Gas Fuel Consumption

Utility documentation showing the amount of fuel consumed by each SGIP project must be provided. In this report, metered fuel consumption data provided by the gas distribution company or other SGIP program participants are used to determine gas fuel consumption.

Usage Determination

SGIP projects are assumed to procure no more than 75% of their fuel input as directed biogas. The directed biogas delivered is compared to 75% of the project's fuel consumption. If the amount of directed biogas procured is less than 75% of the project's fuel consumption, then the project is out of compliance with the SGIP's renewable fuel use requirements. If the amount of directed biogas procured is equal to 75% of the project's fuel consumption, then the project is in compliance with the SGIP's renewable fuel use requirements. If the amount of directed biogas procured is greater than 75% of the project's fuel consumption, then the project is in compliance with the SGIP's renewable fuel use requirements and the remaining directed biogas over 75% of the project's fuel input will be considered pooled for future use. Once the pool is depleted, it cannot be borrowed against.

Fuel Use at Directed Biogas RFUR Projects

When gas marketers procure directed biogas for SGIP projects, they do not purchase renewable fuel for each project and transport it to California under separate contracts. Instead they pool SGIP projects into fleets and procure the amount of biogas required to meet the fleet's monthly biogas requirements. The nature of these transactions requires that compliance determinations be made at the fleet level and not at the individual project level.

Fuel Use of Directed Biogas Fleet #1

As of June 30, 2013, directed biogas fleet #1 consists of 41 all-electric fuel cell projects completed between January 2011 and June 2013. Thirty-four of these systems have been operational for at least one calendar year and are required to comply with the SGIP's renewable fuel use requirements. Directed biogas deliveries and consumptions for directed biogas fleet #1 are summarized in Table 9.

Table 9: DBG Transactions for Directed Biogas Fleet #1

Pool Balances and Transactions	Directed Biogas (MMBtu)
Pool Starting Balance on 7/1/2012	316,301
Added During 12-Month Period Ending 6/30/2013	528,343
Consumed During 12-Month Period Ending 6/30/2013	(610,683)
Pool Ending Balance on 6/30/2013	233,961

While consumption exceeded additions during the reporting period, the pool starting balance was sufficiently large to yield a positive pool balance at the end of the 12-month period. Based on the compliance protocols described in this report, the SGIP projects in directed biogas fleet #1 were found to be in compliance with renewable fuel use requirements during this reporting period. A list of the 41 projects included in directed biogas fleet #1 is shown in Table 11.

Fuel Use of Directed Biogas Fleet #2

As of June 30, 2013, directed biogas fleet # 2 consists of 10 fuel cell projects completed between November 2010 and February 2012. All 10 of these systems have been operational for at least one calendar year and are required to comply with the SGIP's renewable fuel use requirements. Directed biogas deliveries for directed biogas fleet # 2 are summarized in Table 10. However, data quantifying the amount of directed biogas consumed by the 10 projects in fleet #2 were not made available to Itron in time for the report. Consequently, the compliance of the 10 fuel cells in directed biogas fleet #2 remains 'To Be Determined' until the required data and documentation are available.

Table 10: Fuel Usage for Directed Biogas Fleet #2

Pool Balances and Transactions	Directed Biogas (MMBtu)
Pool Starting Balance on 7/1/2012	TBD
Added During 12-Month Period Ending 6/30/2013	202,573
Consumed During 12-Month Period Ending 6/30/2013	TBD
Pool Ending Balance on 6/30/2013	TBD

A list of the 10 projects included in directed biogas fleet #2 is shown in Table 11.

Fuel Use of Directed Biogas Fleet #3

As of June 30, 2013, directed biogas fleet #3 consists of six fuel cell projects completed between March 2011 and April 2012. All six of these systems have been operational for at least one calendar year and are required to comply with the SGIP's renewabl e fuel use requirements. The data and documentation required to evaluate the renewable fuel use compliance of fleet #3 according to the protocols described in this report were not made available to Itron in time for this report. Consequently, the complia nce status of the six fuel cell projects in directed biogas fleet #3 remains 'To Be Determined' until the required data and documentation are available. A list of the six projects included in directed biogas fleet #3 is shown in Table 11.

Fuel Use of other Directed Biogas Projects

As of June 30, 2013, the renewable fuel use compliance of five fuel cell projects cannot be determined. These five projects are not part of large fleets like those discussed previously. Instead, their biogas procurements an d usages are managed by smaller gas schedulers. All five of these systems have been operational for at least one calendar year and are required to comply with the SGIP's renewable fuel use requirements. The data and documentation required to evaluate the renewable fuel use compliance of these projects according to the protocols described in this report were not made available to Itron in time for this report. Consequently, the compliance status of these five fuel cell projects remains 'To Be Determined' until the required data and documentation are available. A list of these five projects is shown in Table 11.

Directed Biogas Project Compliance Status Not Yet Applicable

A directed biogas project is assigned compliance status "Not Yet Applicable" if it has not yet been operational for a complete calendar year. There are nine fuel cell projects in this category, seven of which are included in fleet #1. The biogas usage of all projects in a fleet must be accounted for despite their compliance requirements to properly track the pool balance over time. A list of these nine projects is shown in Table 11.

A summary of the 64 directed biogas RFUR projects with active warranties during this reporting period, including those lacking a full year's operational experience, is presented in Table 11.

Table 11: Fuel Use Compliance of Directed Biogas RFUR Projects

PA	SGIP Reservation Number	DBG Fleet #	Tech	Capacity (kW)	Operational Date*	DBG Flow Start Date**	Annual Natural Gas Energy Flow (MMBtu) †	Renewable Fuel Use (% of Total Energy Input)	Meets Program Renewable Fuel Use Requirements?
PG&E	1810	Fleet #2	FC	400	11/10/2010	09/01/2010	25,076	TBD	TBD
PG&E	1811	Fleet #2	FC	400	11/10/2010	09/01/2010	22,779	TBD	TBD
PG&E	1812	Fleet #2	FC	400	11/10/2010	09/01/2010	22,520	TBD	TBD
PG&E	1802	Fleet #2	FC	400	12/22/2010	10/01/2010	24,342	TBD	TBD
CCSE	CCSE-0369-10	Fleet #2	FC	400	12/31/2010	10/01/2010	TBD	TBD	TBD
CCSE	CCSE-0370-10	Fleet #2	FC	400	12/31/2010	10/01/2010	TBD	TBD	TBD
PG&E	1805	TBD	FC	200	01/18/2011	TBD	TBD	TBD	TBD
SCG	2010-012	Fleet #1	FC	1,000	01/24/2011	10/01/2010	38,579	75%	Yes
PG&E	1859	Fleet #2	FC	500	03/11/2011	12/01/2010	29,728	TBD	TBD
PG&E	1871	Fleet #3	FC	300	03/14/2011	TBD	TBD	TBD	TBD
SCE	PY10-004	Fleet #2	FC	800	03/23/2011	10/01/2010	TBD	TBD	TBD
PG&E	1849	Fleet #1	FC	500	05/09/2011	02/01/2011	25,549	75%	Yes
PG&E	1856	Fleet #1	FC	300	05/09/2011	02/01/2011	14,525	75%	Yes
PG&E	1886	Fleet #1	FC	300	05/24/2011	02/01/2011	14,623	75%	Yes
PG&E	1882	Fleet #1	FC	400	05/24/2011	02/01/2011	18,247	75%	Yes
PG&E	1853	Fleet #1	FC	600	05/24/2011	12/01/2010	20,429	75%	Yes
PG&E	1885	Fleet #1	FC	300	05/31/2011	01/01/2011	14,866	75%	Yes
PG&E	1878	Fleet #3	FC	500	06/29/2011	06/01/2011	TBD	TBD	TBD
PG&E	1851	Fleet #1	FC	300	06/29/2011	04/01/2011	17,573	75%	Yes
SCE	PY10-023	Fleet #3	FC	400	08/08/2011	TBD	TBD	TBD	TBD
SCE	PY10-022	Fleet #3	FC	400	08/08/2011	TBD	TBD	TBD	TBD

PA	SGIP Reservation Number	DBG Fleet #	Tech	Capacity (kW)	Operational Date*	DBG Flow Start Date**	Annual Natural Gas Energy Flow (MMBtu) †	Renewable Fuel Use (% of Total Energy Input)	Meets Program Renewable Fuel Use Requirements?
SCE	PY10-012	Fleet #1	FC	300	08/08/2011	12/01/2010	14,598	75%	Yes
SCE	PY10-009	Fleet #1	FC	300	08/08/2011	03/01/2011	14,724	75%	Yes
PG&E	1850	Fleet #1	FC	420	09/07/2011	06/01/2011	19,296	75%	Yes
PG&E	1892	Fleet #1	FC	210	09/07/2011	06/01/2011	9,181	75%	Yes
PG&E	1874	Fleet #2	FC	500	09/07/2011	03/01/2011	30,367	TBD	TBD
PG&E	1893	Fleet #1	FC	210	09/07/2011	06/01/2011	7,983	75%	Yes
SCG	2010-005	Fleet #1	FC	100	09/20/2011	03/01/2011	6,346	75%	Yes
SCG	2010-011	Fleet #1	FC	900	09/21/2011	05/01/2011	48,481	75%	Yes
PG&E	1855	Fleet #1	FC	300	09/29/2011	07/01/2011	17,287	75%	Yes
SCE	PY10-014	Fleet #1	FC	420	11/15/2011	06/01/2011	14,195	75%	Yes
SCG	2010-020	Fleet #1	FC	420	12/15/2011	09/01/2011	18,355	75%	Yes
SCG	2010-019	Fleet #1	FC	420	12/15/2011	07/01/2011	17,584	75%	Yes
SCG	2010-018	Fleet #1	FC	420	12/15/2011	08/01/2011	19,464	75%	Yes
SCG	2010-015	Fleet #1	FC	420	12/16/2011	09/01/2011	18,251	75%	Yes
CCSE	CCSE-0361-09	TBD	FC	1,400	12/21/2011	TBD	TBD	TBD	TBD
CCSE	CCSE-0375-10	Fleet #1	FC	300	12/21/2011	10/01/2011	13,555	75%	Yes
CCSE	CCSE-0363-09	TBD	FC	2,800	12/21/2011	TBD	TBD	TBD	TBD
PG&E	1929	Fleet #3	FC	420	12/29/2011	TBD	TBD	TBD	TBD
PG&E	1858	Fleet #1	FC	300	12/29/2011	10/01/2011	13,435	75%	Yes
PG&E	1857	Fleet #1	FC	300	12/29/2011	10/01/2011	15,395	75%	Yes
PG&E	1877	Fleet #1	FC	200	12/29/2011	10/01/2011	10,120	75%	Yes
PG&E	1876	Fleet #1	FC	200	12/29/2011	10/01/2011	10,120	75%	Yes

PA	SGIP Reservation Number	DBG Fleet #	Tech	Capacity (kW)	Operational Date*	DBG Flow Start Date**	Annual Natural Gas Energy Flow (MMBtu) †	Renewable Fuel Use (% of Total Energy Input)	Meets Program Renewable Fuel Use Requirements?
PG&E	1852	Fleet #1	FC	400	12/29/2011	10/01/2011	20,448	75%	Yes
PG&E	1869	Fleet #1	FC	600	12/29/2011	10/01/2011	25,614	75%	Yes
PG&E	1868	Fleet #1	FC	400	12/29/2011	10/01/2011	25,614	75%	Yes
CCSE	CCSE-0376-10	Fleet #1	FC	210	02/27/2012	12/01/2011	9,816	75%	Yes
CCSE	CCSE-0374-10	Fleet #1	FC	210	02/27/2012	12/01/2011	8,917	75%	Yes
PG&E	1926	Fleet #2	FC	400	02/28/2012	12/01/2011	TBD	TBD	TBD
PG&E	1860	Fleet #1	FC	800	02/28/2012	12/01/2011	37,039	75%	Yes
SCE	PY10-028	Fleet #1	FC	600	03/28/2012	12/01/2011	31,317	75%	Yes
SCE	PY10-011	Fleet #1	FC	210	03/28/2012	12/01/2011	8,184	75%	Yes
PG&E	PGE-SGIP-2011-1950	Fleet #3	FC	500	04/11/2012	TBD	TBD	TBD	TBD
CCSE	CCSE-0398-10	TBD	FC	420	05/01/2012	TBD	TBD	TBD	TBD
CCSE	CCSE-0399-10	TBD	FC	630	05/01/2012	TBD	TBD	TBD	TBD
SCE	PY10-039	Fleet #1	FC	315	08/08/2012	04/01/2012	17,402	TBD	Not Yet Required
SCE	PY10-038	Fleet #1	FC	630	10/04/2012	05/01/2012	34,457	TBD	Not Yet Required
SCE	PY10-035	TBD	FC	1,110	12/17/2012	TBD	TBD	TBD	Not Yet Required
SCE	PY10-041	Fleet #1	FC	840	12/24/2012	07/01/2012	45,200	TBD	Not Yet Required
SCE	PY10-037	Fleet #1	FC	1,050	12/24/2012	06/01/2012	57,257	TBD	Not Yet Required
SCE	PY10-024	Fleet #1	FC	1,050	03/29/2013	10/01/2012	33,030	TBD	Not Yet Required
PG&E	1914	TBD	FC	420	05/29/2013	TBD	TBD	TBD	Not Yet Required
SCG	2010-033	Fleet #1	FC	105	06/19/2013	03/01/2013	2,585	TBD	Not Yet Required
SCG	2010-034	Fleet #1	FC	210	06/20/2013	03/01/2013	2,585	TBD	Not Yet Required

* Since assignment of a project's operational date is subject to individual judgment, the incentive payment date as reported by the PAs is used as a proxy for the operational date for reporting purposes.

** This field represents the date the project began consuming directed biogas.

† This field represents the natural gas consumption during the 12-month period ending June 30, 2013. The basis is the higher heating value (HHV) of the fuel.

5. Greenhouse Gas Emissions Impacts

Due to increased interest in the GHG emission aspects of biogas projects, information regarding GHG emission impacts is presented in this section. The GHG emission information presented here is derived from data used to prepare the SGIP Twelfth-Year Impact Evaluation Final Report. Additionally, key factors that could influence GHG emission impacts from renewable fuel projects in the future are discussed.

Table 12 presents capacity-weighted average GHG emission results developed for 2012. Results in Table 12 suggest one important observation: The baseline assumed for the biogas (i.e., whether the biogas would have been vented to the atmosphere or flared) is the most influential determinant of GHG emission impacts.[12] This is due to the global warming potential of methane (CH_4) vented directly into the atmosphere, which is much higher than the global warming potential of CO_2 resulting from the flaring of CH_4.

Table 12: Summary of GHG Emission Impacts from SGIP Biogas Projects in 2012

Baseline Biogas Assumption	Prime Mover Technology	Avg. GHG Impact (Metric Tons CO_2(eq) /MWh)
Flare	FC – CHP	-0.45
	FC – Elec.	-0.35
	IC Engine	-0.50
	MT	-0.45
Vent	IC Engine	-4.60

FC – CHP = CHP fuel cell; IC Engine = internal combustion engine; MT = microturbine

Simplifying assumptions underlying the above results include:

- Heat recovered from RFUR projects was used to satisfy a heating load that otherwise would have been satisfied using biogas (e.g., in a boiler)[13]

[12] The baseline treatment of biogas is an influential determinant of GHG emission 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).

[13] Heat recovered from non-RFUR projects utilizing renewable fuel was assumed to displace natural gas. There are very few such projects. The first Program Year of the SGIP (2001) was the only one in which renewable-fueled systems were required to recover heat and meet system efficiency requirements of Public Utilities Code 218.5 (now 216.6).

- A single representative electrical conversion efficiency was assumed for each technology based on metered data.
  - Fuel Cell - CHP: 38%
  - Fuel Cell – Elec.: 47%
  - IC Engine: 31%
  - Microturbine: 23%

All SGIP annual impact evaluations (Impact Evaluations) prior to the Ninth -Year (2009) Impact Evaluation assumed biogas baselines by type of biomass input and rebated capacity of system. Requirements regarding venting and flaring of biogas projects are governed by a variety of regulations in California. At the local level, venting and flaring at the different types of biogas facilities is regulated by California's 35 air quality agencies.[14] At the state level, the California Air Resources Board (CARB) provides guidelines for control of methane and other volatile organic compounds from biogas facilities.[15] At the federal level, New Source Performance Standards and Emission Guidelines regulate methane capture and use.[16]

Biogas baseline assumptions used to calculate GHG impact estimates for 2007-2009 were based on previous studies.[17,18] Because of the importance of the baseline treatment of biogas in the GHG analysis, SGIP biogas facilities were contacted in 2009 to gather baseline-related information. This research suggested a venting baseline for dairy digesters and a flaring baseline for all other project types. For the 2009 through 2012 Impact Evaluations the biogas baseline was modified for WWTP and food processing SGIP projects smaller than 150 kW.

The evolution of biogas baseline assumptions is summarized in Table 13.

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14 An overview of California's air quality districts is available at: http://www.capcoa.org

15 In June of 2007, CARB approved the Landfill Methane Capture Strategy. See http://www.arb.ca.gov/cc/landfills/landfills.htm for additional information.

16 EPA's Landfill Methane Outreach Program provides background information on control of methane at the federal level. See: http://www.epa.gov/lmop/

17 California Energy Commission, *Landfill Gas-to-Energy Potential in California*, CEC Report 500-02-041V1, September 2002.

18 Simons, G., and Zhang, Z., "Distributed Generation From Biogas in California," presented at Interconnecting Distributed Generation Conference, March 2001.

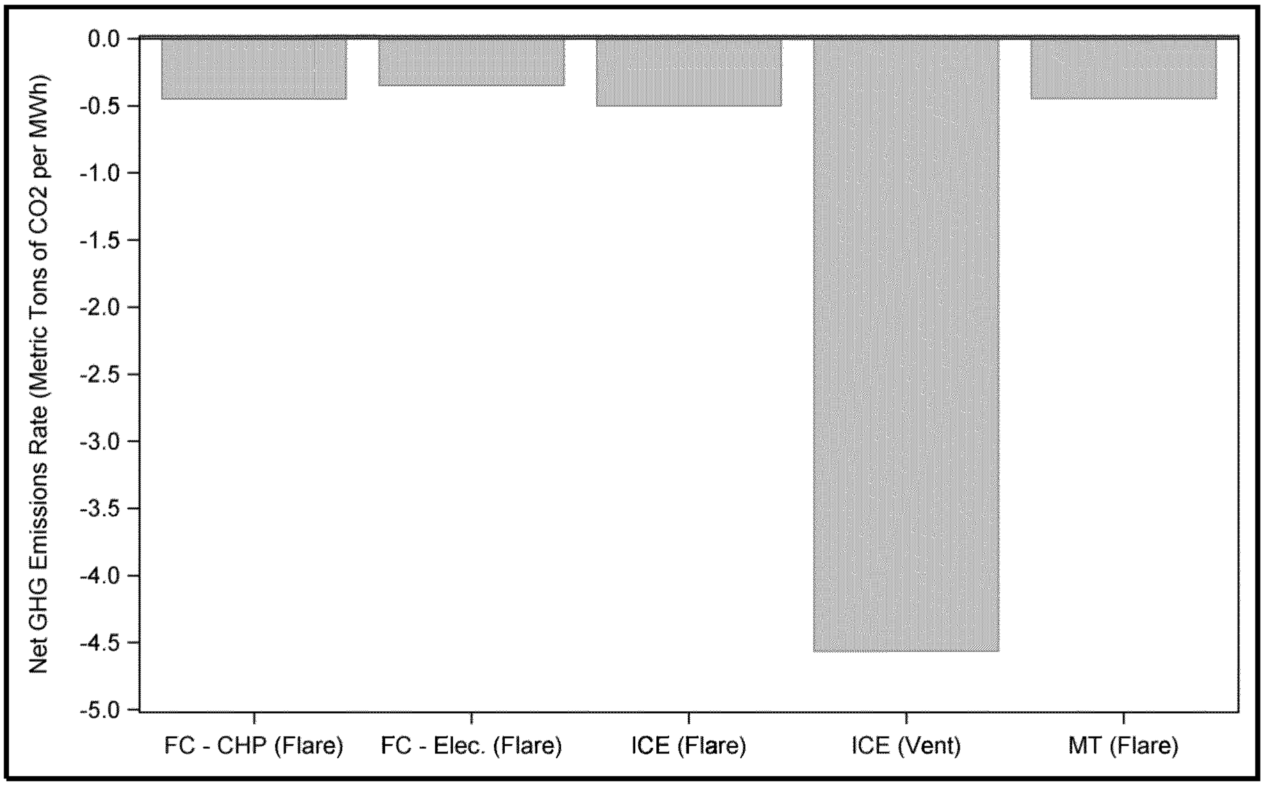
Table 13: Biogas Baseline Assumptions

Renewable Fuel Source	Facility Type*	Size of Rebated System (kW)	Impact Report	
			PY07-08	PY09-12
Digester Gas	WWTP	<150	Vent	Flare
		≥150	Flare	Flare
Digester Gas	Food Processing	<150	Vent	Flare
		≥150	Flare	Flare
Landfill Gas	Landfill	All Sizes	Flare	Flare
Digester Gas	Dairy	All Sizes	Vent	Vent

* WWTP = Waste Water Treatment Plant

The equivalent tons of CO_2 emissions associated with SGIP systems for which flaring and venting baselines were assumed for 2012 are presented in Figure 9. GHG emission impacts are depicted graphically as the difference between SGIP emissions and the total baseline emissions. Total baseline emissions exceed SGIP emissions in all cases; hence a reduction in GHG emissions is attributed to participation in the SGIP.

Figure 9: Summary of GHG Emission Impacts from SGIP Biogas Projects in 2012



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The baseline assumption (i.e ., flaring versus venting) made for biogas used in SGIP systems is the factor exerting the greatest influence over estimates of GHG impacts. Biogas projects for which a venting baseline is assumed achieve significantly greater GHG reductions per unit of electricity generated than those for which a flaring baseline is assumed.

6. Cost Comparison between RFU and Other Projects

Beginning in September 2002, RFUR projects were eligible for a higher incentive level than non-renewable projects. [19] The size of this incentive premium was designed to account for numerous factors, including:

- RFUR projects face higher fuel pre-treatment costs
- RFUR projects might not face heat recovery equipment costs
- RFUR projects do not face fuel purchase expenses

Concerns were expressed in CPUC Decision 02-09-051 that RFUR project costs could fall below non-renewable project costs as RFUR projects are exempt from waste heat recovery requirements. As a result, RFUR projects could potentially be receiving a greater-than-necessary incentive, which could lead to fuel switching. To address this concern, the CPUC directed SGIP PAs to monitor non-renewable project and RFUR project costs.

Eligible project costs from all completed SGIP projects provide the data for monitoring and analyzing differences in project costs. However, these are historical costs, raising a key question faced by the CPUC and other Program designers:

How accurately do the cost differences calculated for projects completed in the past represent the cost differences that are likely to be faced by Program participants in the future?

This question is difficult to answer and the answer depends on many factors, including:

1. The number of projects completed in the past.
2. The variability exhibited by cost data for the projects completed in the past.
3. The possible changes in system costs through time yielded by experience, economies of scale, and/or technology innovation.

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[19] In September 2002 RFUR projects were classified as "Level 3 -R" projects. Since that time the definitions of Levels have changed numerous times. Itron has moved away from using incentive levels in the annual Impact Evaluation and Renewable Fuel Use reports because of the confusion caused by these changes

The following analysis provides insight into mean costs and cost differences due to renewable fuel use and heat recovery.

Eligible installed costs for all fuel cell, microturbine, and IC engine projects operational as of June 30, 2013, are summarized in Table 14, along with simple summary statistics. The summary distinguishes between fuel type and heat recovery incidence to facilitate independent examination of the principal factors influencing costs of projects utilizing renewable fuel. Several of the groups comprise only a few projects and others have extreme variability in project costs, greater than an order of magnitude. Sample sizes and overall cost variability play a very important role in the ability to draw conclusions from the data. The combined influence of sample size and sample variab ility on the inferential statistics is discussed below in the section titled *Uncertainty Analysis*.

Table 14: Summary of Project Costs by Technology, Heat Recovery Provisions & Fuel Type

Tech	Includes Renewable Fuel?*	Includes Heat Recovery?	No. Projects	$/Watt Eligible Installed Costs				
				Range	Median	Mean	Std. Dev.	Size-Wtd. Avg.
FC – CHP	Yes	Yes	14	4.51 – 10.98	7.15	7.83	2.29	6.62
	Yes	No	1	6.80 – 6.80	6.80	6.80	-	6.80
	Yes	Yes or No	15	4.51 – 10.98	6.97	7.76	2.22	6.62
	No	Yes	22	5.06 – 18.00	7.42	8.54	3.36	7.73
FC – Elec.	No	No	44	3.57 – 15.54	10.61	10.62	1.87	9.29
	DBG	No	64	5.09 – 18.21	11.18	10.60	2.32	7.71
ICE	Yes	Yes	21	1.08 - 7.58	2.81	3.11	1.56	3.01
	Yes	No	5	0.85 – 10.71	2.64	2.23	0.73	2.53
	Yes	Yes or No	26	1.08 - 7.58	2.76	2.94	1.47	2.90
	No	Yes	230	0.85 - 10.71	2.31	2.61	1.32	2.31
MT	Yes	Yes	11	2.26 - 11.32	3.40	4.85	2.84	4.26
	Yes	No	13	1.23 – 7.01	3.75	3.93	1.64	3.33
	Yes	Yes or No	24	1.23 - 11.32	3.61	4.36	2.27	3.70
	No	Yes	116	0.70 - 8.40	3.21	3.34	1.31	3.25

FC – CHP = CHP fuel cell; FC – Elec. = Electric-only fuel cell; MT = microturbine; ICE = internal combustion engine; DBG = directed biogas.

* To assess the difference in costs between those technologies using renewable fuel resources versus those using only non-renewable fuels, fuel types are differentiated in Table 11 by identifying those using any amount of renewable fuel with a "Yes" classification.

The cost of waste heat recovery equipment and fuel clean-up may account for much of the difference between renewable and non-renewable project costs. Heat recovery equipment and fuel clean-up equipment cost comparisons are described below.

Heat Recovery Equipment Costs

The cost difference due to heat recovery equipment can be evaluated by comparing costs of projects with heat recovery to the costs of otherwise similar projects without heat recovery. The analysis is limited to projects that use renewable fuel to keep that variable constant and since those are the projects of most interest in this report. Additionally, analysis is performed separately for each technology type. For example, the cost difference due to heat recovery equipment for microturbine projects is calculated as $4.85 minus $3.93, or $0.92.

$$\Delta Heat\,\mathrm{Recovery} = \begin{pmatrix} RFU \\ w/\,HR \end{pmatrix} - \begin{pmatrix} RFU \\ w/\,o\,HR \end{pmatrix}$$ **Equation 1**

Where

RFU w/ HR = renewable fuel use with heat recovery

RFU w/o HR = renewable fuel use without heat recovery

Table 15: Cost Effect of Heat Recovery

Tech	Includes Renewable Fuel?	Includes Heat Recovery?	No. Projects	$/Watt Eligible Installed Costs				
				Range	Median	Mean	Std. Dev.	Size-Wtd. Avg.
FC - CHP	Yes	Yes	14	4.51-10.98	7.51	7.83	2.29	6.62
ICE	Yes	Yes	21	1.08- 7.58	2.81	3.11	1.56	3.01
	Yes	No	5	1.21- 2.87	2.64	2.23	0.73	2.53
	Increase due to Heat Recovery		-	-	0.18	0.88	0.83	0.48
MT	Yes	Yes	11	2.26-11.32	3.40	4.85	2.84	4.26
	Yes	No	13	1.23- 7.01	3.75	3.93	1.64	3.33
	Increase due to Heat Recovery		-	-	-0.35	0.92	1.21	0.93

The mean costs for heat recovery are higher than non-heat recovery systems. The statistical significance of these differences is examined later in this report with uncertainty analysis. Note there was only one renewable fueled CHP fuel cell that did not include heat recovery, so it is not possible to perform this analysis for fuel cells.

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Fuel Treatment Equipment Costs

Renewable fueled projects utilize fuel treatment equipment, which is usually used for gas clean - up, such as removal of hydrogen sulfide. To examine whether this fuel treatment equipment significantly increases project costs, the differences in costs betwe en renewable and non - renewable fueled projects are analyzed. However, we must take into account whether the project also includes heat recovery equipment to avoid confounding the results. The analysis is limited to projects with heat recovery for this re ason and to maximize the sample size of non -renewable fueled projects. Any difference observed between the costs of these two groups could be due to the difference in provisions for fuel treatment. For example, the cost difference for fuel treatment equipment in IC engine projects is calculated as $3.11 minus $2.61, or $0.50.

$$\Delta FuelTreatment = \begin{pmatrix} RFU \\ w/HR \end{pmatrix} - \begin{pmatrix} NG \\ w/HR \end{pmatrix}$$ **Equation 2**

Where

NG = natural gas

Table 16: Cost Effect of Renewable Fuel Treatment Equipment

Tech	Includes Renewable Fuel?	Includes Heat Recovery?	No. Projects	$/Watt Eligible Installed Costs				
				Range	Median	Mean	Std. Dev.	Size-Wtd. Avg.
FC - CHP	Yes	Yes	14	4.51 - 10.98	7.15	7.83	2.29	6.62
	No	Yes	22	5.06 - 18.00	7.42	8.54	3.36	7.73
	Increase due to RF Equipment		-	-	-0.27	-0.71	-1.07	-1.11
ICE	Yes	Yes	21	1.08 - 7.58	2.81	3.11	1.56	3.01
	No	Yes	230	0.85 – 10.71	2.31	2.61	1.32	2.31
	Increase due to RF Equipment		-	-	0.51	0.50	0.24	0.70
MT	Yes	Yes	11	2.26 - 11.32	3.40	4.85	2.84	4.26
	No	Yes	116	0.70 - 8.40	3.21	3.34	1.31	3.25
	Increase due to RF Equipment		-	-	0.20	1.51	1.53	1.01

The mean and median costs of renewable fueled IC Engine and microturbine projects are higher than non-renewable fueled projects. Interestingly, for renewable fueled CHP fuel cells, the mean and median costs are higher than non-renewable systems. Costs for all technology and fuel types display great variability, making it difficult to draw significant conclusions about cost

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differences for renewable fueled systems. Statistical significance of the results is further explored via uncertainty analysis later in this report.

Overall RFU Costs

An alternative and more general analysis of cost differences between renewable and non-renewable fueled projects is to compare costs of the two groups without regard to heat recovery provision. Note that all of the non-renewable fuel projects include heat recovery equipment, with the exception of a few CHP fuel cell projects, and many of the renewable fuel projects include heat recovery even though many were not required to do so. By looking at the observed difference in costs of these two groups, it is possible to see the average overall influence of the different SGIP requirements for renewable and non-renewable projects. For example, the cost difference between renewable and non-renewable fueled IC engine projects is calculated as \$2.94 minus \$2.61, or \$0.33.

$$\Delta RFU = \left(\frac{RFU}{w/or\,w/o\ HR}\right) - \left(\frac{NG}{w/HR}\right) \qquad \textbf{Equation 3}$$

Table 17: Cost Effect of Renewable Fuel Use

Tech	Includes Renewable Fuel?	Includes Heat Recovery?	No. Projects	\$/Watt Eligible Installed Costs: Range	Median	Mean	Std. Dev.	Size-Wtd. Avg.
FC - CHP	Yes	Yes or No	15	4.51 - 10.98	6.97	7.76	2.22	6.62
	No	Yes	22	5.06 - 18.00	7.42	8.54	3.36	7.73
	Increase due to RFU		-	-	-0.45	-0.79	-1.14	-1.10
ICE	Yes	Yes or No	26	1.08 - 7.58	2.76	2.94	1.47	2.90
	No	Yes	230	0.85 - 10.71	2.31	2.61	1.32	2.31
	Increase due to RFU		-	-	0.45	0.33	0.15	0.59
MT	Yes	Yes or No	24	1.23 - 11.32	3.61	4.36	2.27	3.70
	No	Yes	116	0.70 - 8.40	3.21	3.34	1.31	3.25
	Increase due to RFU		.		0.40	1.01	0.95	0.44

Uncertainty Analysis

This section augments the difference of means analysis with an uncertainty analysis that provides a confidence interval for the mean differences. The confidence intervals are calculated with the sample statistics (e.g., n, mean, and std. dev.) presented in Table 14. The presented confidence intervals are based on a 90 percent confidence level, meaning there is 90 percent confidence that the true mean difference falls within the stated range. Note that if the range spans across zero, it is possible that there is no difference in cost between the two groups being analyzed.

Microturbine Project Cost Comparisons

Cost comparison results for microturbines are summarized in Table 18. These data show, for instance, that the average incremental cost associated with presence of heat recovery was $ 0.92 per watt for SGIP participants with completed projects. When this value is used to estimate the incremental cost of heat recovery not only for completed projects but also for projects that will be completed in the future, it is necessary to summarize the uncertainty of the estimate.[20]

Table 18: Microturbine Project Cost Comparison Summary

Physical Difference	Difference of Means ($/Watt)	90% Confidence Interval ($/Watt)
Heat Recovery	0.92	-0.68 to 2.51
Fuel Treatment	1.51	0.73 to 2.29
RFU	1.01	0.45 to 1.57

The 90 percent confidence intervals presented in Table 18 summarize uncertainty in estimates of the incremental costs associated with several key physical differences for the population comprising projects already completed as well as those that will be completed in the future. For heat recovery, the lower bound of the confidence interval is -68 cents per watt. This counterintuitive result implies that systems without heat recovery might cost less than those with it. The possibility of this unlikely result, along with the very large confidence interval, are likely simply due to the small quantity of, and considerable variability exhibited by cost data available for SGIP projects completed in the past. This is a representative example of the general rule that caution must be exercised when interpreting summary statistics when sample sizes are small.

IC Engine Project Cost Comparisons

Cost comparison results for IC engine projects are summarized in Table 19. The differences between means are small in comparison to the variability exhibited by past costs of renewable

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[20] Uncertainty is assessed by calculating confidence intervals around the point estimates. Standard statistical tests are used to describe the likelihood that the two samples underlying the two means used to calculate each incremental difference came from the same population. When n_1 & $n_2 \geq 30$, a z -Test is used to determine confidence intervals. When n_1 or $n_2 < 30$, a t-Test is used.

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fuel projects. This variability, combined with relatively small numbers of renewable fuel projects, results in very large confidence intervals. Each of the confidence intervals span across zero, meaning there is not 90% confidence that there is a difference in cost for the factors analyzed.

Table 19: IC Engine Project Cost Comparison Summary

Physical Difference	Difference of Means ($/Watt)	90% Confidence Interval ($/Watt)
Heat Recovery	0.88	-0.36 to 2.12
Fuel Treatment	0.50	0.00 to 1.01
RFU	0.33	-0.12 to 0.79

CHP Fuel Cell Project Cost Comparisons

Due to the sensitivity of fuel cells to contaminants in the gas stream, gas clean -up costs for fuel cells powered by renewable fuels—which contain sulfur, halide, and other contaminants—should be higher than gas clean-up costs for fuel cells operating with cleaner fuels, such as natural gas. Cost comparison results for fuel cells are summarized in Table 20. Results for the incremental difference due to heat recovery are not presented because all but one of the renewable fuel cell projects completed to date have included heat recovery even though they were not required to by the SGIP. The 90 percent confidence interval for fuel cells is very large, which is not surprising given the emerging status of this te chnology and the small number of facilities. Again, the confidence intervals span across zero and there is not 90% confidence that cost differences exist for the analyzed factors.

Table 20: CHP Fuel Cell Project Cost Comparison Summary

Physical Difference	Difference of Means ($/Watt)	90% Confidence Interval ($/Watt)
Heat Recovery	---	---
Fuel Treatment	-0.71	-2.45 to 1.02
RFU	-0.79	-2.46 to 0.89

Cost Comparison Summary

Comparison of the installed costs between renewable- and non-renewable fueled generation systems operational as of June 30, 2013, reveals that average non-renewable generator costs have typically been lower than average renewable-fueled generator costs. However, these averages pertain to past Program participants. The fundamental question motivating examination of RFUR project costs is stated explicitly below:

Do SGIP project cost data for past participants suggest that project costs are changing in ways that could necessitate modification of incentive levels received by future SGIP participants?

Confidence intervals calculated for populations comprising both past *and* future SGIP participants are very large. In fact, these confidence intervals prevent drawing conclusions about cost differences in IC engine and CHP fuel cell projects; only microturbine projects exhibit cost differences at 90% confidence. This suggests that data for past projects should not be used as the sole basis for SGIP design elements affecting future participants. Engineering estimates, budget cost data, and rules-of-thumb likely continue to be more suitable for this purpose at this time.

Appendix A

List of All SGIP Projects Utilizing Renewable Fuel

All SGIP projects supplied with renewable fuel are listed in Table 21. Renewable Fuel Use Requirement (RFUR) projects subject to renewable fuel use requirements and exempt from heat recovery requirements are identified in the column titled "RFUR Project ?" Only a portion of these projects (about 67 percent) are also equipped with a non -renewable fuel supply. The se projects are identified in the "Any Non-Renewable Fuel Supply?" column.

Table 21: SGIP Projects Utilizing Renewable Fuel

Res No.	PA	Incentive Level	Tech	Renewable Fuel Type	Capacity (kW)	Operational Date*	RFUR Project?	Any Non-Renewable Fuel Supply?
CCSE-0007-01	CCSE	Level 3	MT	DG - WWTP	84	08/30/2002	No	No
PY02-055	SCE	Level 3R	MT	Landfill Gas	420	05/19/2003	Yes	No
PY01-031	SCE	Level 3	ICE	Landfill Gas	991	09/29/2003	No	No
110	PG&E	Level 3	ICE	DG - WWTP	900	10/23/2003	No	Yes
PY02-074	SCE	Level 3R	MT	Landfill Gas	300	02/11/2004	Yes	No
CCSE-0026-01	CCSE	Level 3	MT	DG - WWTP	120	04/23/2004	No	No
514	PG&E	Level 3R	MT	DG - WWTP	90	05/19/2004	Yes	No

Res No.	PA	Incentive Level	Tech	Renewable Fuel Type	Capacity (kW)	Operational Date*	RFUR Project?	Any Non-Renewable Fuel Supply?
CCSE-0023-01	CCSE	Level 3	MT	DG - WWTP	360	09/03/2004	No	No
379	PG&E	Level 3R	MT	Landfill Gas	280	01/14/2005	Yes	No
PY03-092	SCE	Level 1	FC - CHP	DG - WWTP	500	03/11/2005	Yes	Yes
640	PG&E	Level 3R	MT	Landfill Gas	70	04/14/2005	Yes	No
641	PG&E	Level 3R	MT	Landfill Gas	70	04/14/2005	Yes	No
PY03-045	SCE	Level 1	FC - CHP	DG - WWTP	250	04/19/2005	Yes	No
PY03-017	SCE	Level 3R	ICE	DG - WWTP	500	05/11/2005	Yes	Yes
PY03-008	SCE	Level 3R	MT	Landfill Gas	70	05/11/2005	Yes	No
842A	PG&E	Level 3R	MT	DG - WWTP	60	05/27/2005	Yes	No
PY03-038	SCE	Level 3R	MT	DG - WWTP	250	07/12/2005	Yes	No
747	PG&E	Level 3R	MT	DG - WWTP	60	07/18/2005	Yes	No
653	PG&E	Level 2	FC - CHP	DG - Food Processing	1,000	08/09/2005	No	Yes
833	PG&E	Level 3N	MT	DG - Food Processing	70	11/07/2005	No	Yes
483	PG&E	Level 3R	ICE	DG - Dairy	300	01/13/2006	Yes	No

Res No.	PA	Incentive Level	Tech	Renewable Fuel Type	Capacity (kW)	Operational Date*	RFUR Project?	Any Non-Renewable Fuel Supply?
313	PG&E	Level 3R	MT	DG - WWTP	300	03/16/2006	Yes	No
1297	PG&E	Level 3R	MT	DG - WWTP	280	04/07/2006	Yes	No
856	PG&E	Level 3R	MT	Landfill Gas	210	05/05/2006	Yes	No
658	PG&E	Level 3R	ICE	DG - Dairy	160	05/22/2006	Yes	No
1222	PG&E	Level 3R	ICE	Landfill Gas	970	07/05/2006	Yes	No
1316	PG&E	Level 3R	ICE	Landfill Gas	970	10/02/2006	Yes	No
PY04-158	SCE	Level 3R	ICE	DG - WWTP	704	10/25/2006	Yes	Yes
PY04-159	SCE	Level 3R	ICE	DG - WWTP	704	10/26/2006	Yes	Yes
1308	PG&E	Level 3R	ICE	DG - Dairy	400	11/17/2006	Yes	No
1505	PG&E	Level 2	ICE	Landfill Gas	970	11/24/2006	Yes	No
298	PG&E	Level 3R	MT	DG - WWTP	30	01/31/2007	Yes	No
1313	PG&E	Level 3R	MT	DG - WWTP	240	03/06/2007	Yes	Yes
PY05-093	SCE	Level 3R	ICE	Landfill Gas	1,030	03/16/2007	Yes	No
1559	PG&E	Level 2	ICE	DG - WWTP	160	05/16/2007	Yes	No

Res No.	PA	Incentive Level	Tech	Renewable Fuel Type	Capacity (kW)	Operational Date*	RFUR Project?	Any Non-Renewable Fuel Supply?
1298	PG&E	Level 3N	MT	DG - WWTP	250	06/11/2007	No	Yes
1528	PG&E	Level 2	MT	DG - Food Processing	70	06/15/2007	Yes	No
PY06-094	SCE	Level 2	ICE	DG - WWTP	500	11/08/2007	Yes	No
1577	PG&E	Level 2	ICE	DG - Dairy	80	12/31/2007	Yes	No
2005-082	SCG	Level 3R	ICE	DG - Food Processing	1,080	01/15/2008	Yes	No
2006-014	SCG	Level 2	ICE	Landfill Gas	1,030	02/21/2008	Yes	No
PY06-062	SCE	Level 2	FC - CHP	DG - WWTP	900	03/04/2008	Yes	Yes
CCSE-0270-05	CCSE	Level 3R	MT	Landfill Gas	210	04/04/2008	Yes	No
1490	PG&E	Level 2	FC - CHP	DG - WWTP	600	04/24/2008	Yes	Yes
1640	PG&E	Level 3R	ICE	DG - WWTP	643	07/29/2008	Yes	No
1498	PG&E	Level 3R	MT	Landfill Gas	210	08/05/2008	Yes	No
2006-036	SCG	Level 2	FC - CHP	DG - WWTP	1,200	10/27/2008	Yes	Yes
1749	PG&E	Level 3R	ICE	DG - WWTP	130	11/09/2009	Yes	Yes
2008-003	SCG	Level 2	FC - CHP	DG - Food Processing	600	12/14/2009	Yes	Yes

Res No.	PA	Incentive Level	Tech	Renewable Fuel Type	Capacity (kW)	Operational Date*	RFUR Project?	Any Non-Renewable Fuel Supply?
2006-012	SCG	Level 2	FC - CHP	DG - WWTP	900	12/18/2009	Yes	Yes
1775	PG&E	Level 2	ICE	DG - Dairy	75	02/03/2010	Yes	No
CCSE-0351-07	CCSE	Level 2	ICE	DG - WWTP	560	04/16/2010	Yes	Yes
PY10-002	SCE	Level 2	FC - CHP	DG - WWTP	500	10/31/2010	Yes	Yes
1810	PG&E	Level 2	FC - Elec.	Directed Biogas	400	11/10/2010	Yes	Yes
1811	PG&E	Level 2	FC - Elec.	Directed Biogas	400	11/10/2010	Yes	Yes
1812	PG&E	Level 2	FC - Elec.	Directed Biogas	400	11/10/2010	Yes	Yes
1802	PG&E	Level 2	FC - Elec.	Directed Biogas	400	12/22/2010	Yes	Yes
1761	PG&E	Level 2	ICE	DG - WWTP	330	12/23/2010	Yes	No
1759	PG&E	Level 2	ICE	DG - WWTP	1,696	12/24/2010	Yes	No
CCSE-0369-10	CCSE	Level 2	FC - Elec.	Directed Biogas	400	12/31/2010	Yes	Yes
CCSE-0370-10	CCSE	Level 2	FC - Elec.	Directed Biogas	400	12/31/2010	Yes	Yes
1805	PG&E	Level 2	FC - Elec.	Directed Biogas	200	01/18/2011	Yes	Yes
2010-012	SCG	Level 2	FC - Elec.	Directed Biogas	1,000	01/24/2011	Yes	Yes

Res No.	PA	Incentive Level	Tech	Renewable Fuel Type	Capacity (kW)	Operational Date*	RFUR Project?	Any Non-Renewable Fuel Supply?
1859	PG&E	Level 2	FC - Elec.	Directed Biogas	500	03/11/2011	Yes	Yes
1871	PG&E	Level 2	FC - Elec.	Directed Biogas	300	03/14/2011	Yes	Yes
PY10-004	SCE	Level 2	FC - Elec.	Directed Biogas	800	03/23/2011	Yes	Yes
1856	PG&E	Level 2	FC - Elec.	Directed Biogas	300	05/09/2011	Yes	Yes
1849	PG&E	Level 2	FC - Elec.	Directed Biogas	500	05/09/2011	Yes	Yes
1853	PG&E	Level 2	FC - Elec.	Directed Biogas	600	05/24/2011	Yes	Yes
1886	PG&E	Level 2	FC - Elec.	Directed Biogas	300	05/24/2011	Yes	Yes
1882	PG&E	Level 2	FC - Elec.	Directed Biogas	400	05/24/2011	Yes	Yes
1885	PG&E	Level 2	FC - Elec.	Directed Biogas	300	05/31/2011	Yes	Yes
1878	PG&E	Level 2	FC - Elec.	Directed Biogas	500	06/29/2011	Yes	Yes
1851	PG&E	Level 2	FC - Elec.	Directed Biogas	300	06/29/2011	Yes	Yes
2007-013	SCG	Level 2	ICE	DG - WWTP	150	07/13/2011	Yes	No
PY10-012	SCE	Level 2	FC - Elec.	Directed Biogas	300	08/08/2011	Yes	Yes
PY10-023	SCE	Level 2	FC - Elec.	Directed Biogas	400	08/08/2011	Yes	Yes

Res No.	PA	Incentive Level	Tech	Renewable Fuel Type	Capacity (kW)	Operational Date*	RFUR Project?	Any Non-Renewable Fuel Supply?
PY10-009	SCE	Level 2	FC - Elec.	Directed Biogas	300	08/08/2011	Yes	Yes
PY10-022	SCE	Level 2	FC - Elec.	Directed Biogas	400	08/08/2011	Yes	Yes
PY09-003	SCE	Level 2	FC - CHP	DG - WWTP	300	08/30/2011	Yes	Yes
1893	PG&E	Level 2	FC - Elec.	Directed Biogas	210	09/07/2011	Yes	Yes
1874	PG&E	Level 2	FC - Elec.	Directed Biogas	500	09/07/2011	Yes	Yes
1892	PG&E	Level 2	FC - Elec.	Directed Biogas	210	09/07/2011	Yes	Yes
1850	PG&E	Level 2	FC - Elec.	Directed Biogas	420	09/07/2011	Yes	Yes
2010-005	SCG	Level 2	FC - Elec.	Directed Biogas	100	09/20/2011	Yes	Yes
2010-011	SCG	Level 2	FC - Elec.	Directed Biogas	900	09/21/2011	Yes	Yes
PY07-017	SCE	Level 2	ICE	DG - WWTP	364	09/27/2011	Yes	No
1855	PG&E	Level 2	FC - Elec.	Directed Biogas	300	09/29/2011	Yes	Yes
2007-036	SCG	Level 2	ICE	DG - WWTP	340	11/01/2011	Yes	No
PY10-014	SCE	Level 2	FC - Elec.	Directed Biogas	420	11/15/2011	Yes	Yes
2010-020	SCG	Level 2	FC - Elec.	Directed Biogas	420	12/15/2011	Yes	Yes

Res No.	PA	Incentive Level	Tech	Renewable Fuel Type	Capacity (kW)	Operational Date*	RFUR Project?	Any Non-Renewable Fuel Supply?
2010-019	SCG	Level 2	FC - Elec.	Directed Biogas	420	12/15/2011	Yes	Yes
2010-018	SCG	Level 2	FC - Elec.	Directed Biogas	420	12/15/2011	Yes	Yes
2010-015	SCG	Level 2	FC - Elec.	Directed Biogas	420	12/16/2011	Yes	Yes
CCSE-0361-09	CCSE	Level 2	FC - Elec.	Directed Biogas	1,400	12/21/2011	Yes	Yes
CCSE-0375-10	CCSE	Level 2	FC - Elec.	Directed Biogas	300	12/21/2011	Yes	Yes
CCSE-0362-09	CCSE	Level 2	FC - CHP	DG - WWTP	300	12/21/2011	Yes	Yes
CCSE-0363-09	CCSE	Level 2	FC - Elec.	Directed Biogas	2,800	12/21/2011	Yes	Yes
1852	PG&E	Level 2	FC - Elec.	Directed Biogas	400	12/29/2011	Yes	Yes
1929	PG&E	Level 2	FC - Elec.	Directed Biogas	420	12/29/2011	Yes	Yes
1877	PG&E	Level 2	FC - Elec.	Directed Biogas	200	12/29/2011	Yes	Yes
1876	PG&E	Level 2	FC - Elec.	Directed Biogas	200	12/29/2011	Yes	Yes
1858	PG&E	Level 2	FC - Elec.	Directed Biogas	300	12/29/2011	Yes	Yes
1869	PG&E	Level 2	FC - Elec.	Directed Biogas	600	12/29/2011	Yes	Yes
1868	PG&E	Level 2	FC - Elec.	Directed Biogas	400	12/29/2011	Yes	Yes

Res No.	PA	Incentive Level	Tech	Renewable Fuel Type	Capacity (kW)	Operational Date*	RFUR Project?	Any Non-Renewable Fuel Supply?
1857	PG&E	Level 2	FC - Elec.	Directed Biogas	300	12/29/2011	Yes	Yes
CCSE-0376-10	CCSE	Level 2	FC - Elec.	Directed Biogas	210	02/27/2012	Yes	Yes
CCSE-0374-10	CCSE	Level 2	FC - Elec.	Directed Biogas	210	02/27/2012	Yes	Yes
1860	PG&E	Level 2	FC - Elec.	Directed Biogas	800	02/28/2012	Yes	Yes
1926	PG&E	Level 2	FC - Elec.	Directed Biogas	400	02/28/2012	Yes	Yes
PY10-011	SCE	Level 2	FC - Elec.	Directed Biogas	210	03/28/2012	Yes	Yes
PY10-028	SCE	Level 2	FC - Elec.	Directed Biogas	600	03/28/2012	Yes	Yes
PY09-013	SCE	Level 2	FC - CHP	DG - WWTP	600	03/28/2012	Yes	Yes
PGE-SGIP-2011-1950	PG&E	Level 2	FC - Elec.	Directed Biogas	500	04/11/2012	Yes	Yes
CCSE-0399-10	CCSE	Level 2	FC - Elec.	Directed Biogas	630	05/01/2012	Yes	Yes
CCSE-0398-10	CCSE	Level 2	FC - Elec.	Directed Biogas	420	05/01/2012	Yes	Yes
PY07-006	SCE	Level 2	MT	Landfill Gas	750	06/12/2012	Yes	No
PY10-039	SCE	Level 2	FC - Elec.	Directed Biogas	315	08/08/2012	Yes	Yes
PY10-038	SCE	Level 2	FC - Elec.	Directed Biogas	630	10/04/2012	Yes	Yes

Res No.	PA	Incentive Level	Tech	Renewable Fuel Type	Capacity (kW)	Operational Date*	RFUR Project?	Any Non-Renewable Fuel Supply?
SCE-SGIP-2011-0334	SCE	Level 2	FC - CHP	DG - WWTP	250	11/09/2012	Yes	Yes
1867	PG&E	Level 2	FC - CHP	DG - WWTP	1,400	11/29/2012	Yes	Yes
PY10-035	SCE	Level 2	FC - Elec.	Directed Biogas	1,110	12/17/2012	Yes	Yes
2010-026	SCG	Level 2	FC - CHP	DG - WWTP	2800	12/21/2012	Yes	Yes
PY10-037	SCE	Level 2	FC - Elec.	Directed Biogas	1,050	12/24/2012	Yes	Yes
PY10-041	SCE	Level 2	FC - Elec.	Directed Biogas	840	12/24/2012	Yes	Yes
PY10-024	SCE	Level 2	FC - Elec.	Directed Biogas	1,050	03/29/2013	Yes	Yes
1914	PG&E	Level 2	FC - Elec.	Directed Biogas	420	05/29/2013	Yes	Yes
2010-033	SCG	Level 2	FC - Elec.	Directed Biogas	105	06/19/2013	Yes	Yes
2010-034	SCG	Level 2	FC - Elec.	Directed Biogas	210	06/20/2013	Yes	Yes

* Since assignment of a project's operational date is subject to individual judgment, the incentive payment date as reported by the PAs is used as a proxy for the operational date for reporting purposes.