Self-Generation Incentive Program
Semi-Annual Renewable Fuel Use Report No. 17
for the Six-Month Period Ending December 31, 2010

1. Overview

Report Purpose

This report complies with 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. 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 self-generation equipment. 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), formerly the San Diego Regional Energy Office (SDREO), in the 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 SGIP Handbook defines renewable fuels as wind, solar, and gas derived from biomass, landfills, and dairies. 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.

However, 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 has been added to the reports beginning with RFU Report No. 15.

RFU Report No. 17 covers projects completed during the last six months (i.e., July 1, 2010, to December 31, 2010) 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 January 1, 2010, to December 31, 2010.

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, assessing 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 15 lists all RFU

Table 1: Summary of RFU vs. RFUR Parameters

	RFU	
Parameter	**"Other" RFU**	**RFUR**
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	50

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 state board, determines will achieve reduction of greenhouse gas emissions pursuant to the California Global Warming Solutions Act of 2006.

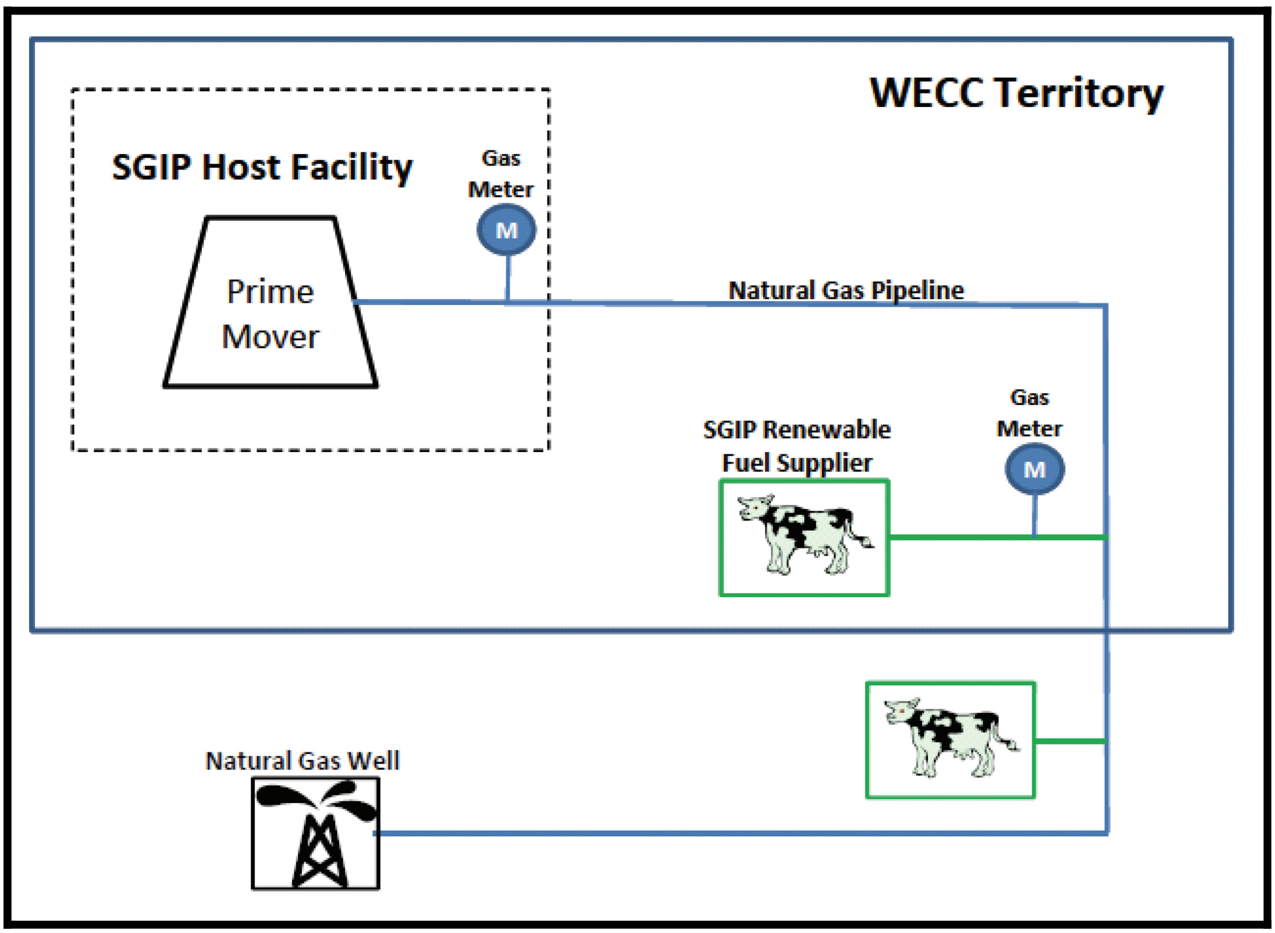
5 The SGIP requires such projects to limit use of non-renewable fuel to 25 percent on an annual fuel energy input basis. This requirement is based on FERC definitions of renewable energy qualifying facilities from the original Public Utility Regulatory Policy Act (PURPA) of 1978.

projects, including those not subject to the Program's minimum renewable fuel use requirements ("Other RFU projects").

Directed Biogas Projects

In CPUC Decision 09-09-048 (September 24, 2009), eligibility for RFUR incentives was expanded to include "directed biogas" projects. Deemed to be renewable fuel use projects, they are eligible for higher incentives under the SGIP, but are also subject to the fuel use requirements of renewable fuel use projects. 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 biogas is not likely to be delivered and used at the SGIP renewable fuel project, the SGIP is credited with the overall increase in biogas production and use. The relative positions of key parties to directed biogas transactions are depicted graphically in Figure 1.

Figure 1: Schematic Depiction of Directed Biogas Arrangement



RFU Report #17 marks the first appearance of completed directed biogas projects under the SGIP. Each of these four fuel cell projects is equipped with an on-site supply of utility-delivered natural gas. As such, the landfill gas is not literally delivered, but notionally delivered, as the biogas may actually be utilized at any other location along the pipeline route. Itron is currently developing methods for assessing compliance of directed biogas projects with SGIP RFU requirements and has begun the process of collecting renewable fuel invoices from program participants.

Summary of RFU Report No. 17 Findings

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

- As of December 31, 2010, there were 58 RFU facilities deployed under the SGIP, representing approximately 26.7 megawatts (MW) of rebated capacity. Fifty of these facilities were RFUR projects and represented approximately 22.9 MW of rebated capacity. The remaining eight "Other" RFU projects represented approximately 3.8 MW of rebated capacity.
- RFU Report #17 marks the first appearance of completed SGIP projects utilizing directed biogas. Four such projects were completed during the second half of 2010. All four projects include natural gas fuel cells operating on-site; SGIP renewable fuel use requirements are satisfied via purchase of landfill gas that is produced off-site.
- Thirty-seven of the 54 RFUR projects (69 percent) operated solely from renewable fuels and as such inherently comply with renewable fuel use requirements. Of the remaining 17 dual-fuel RFUR facilities, one was found to be in compliance with renewable fuel use requirements:
  - Five were found not to be applicable with respect to the requirements as they were no longer required to report compliance status,
  - Six were found not to be applicable with respect to the requirements as they have not yet been operational for a full year, and
  - Five were found to be out of compliance.
- RFU facilities are powered by a variety of renewable fuel (i.e., biogas) resources. However, approximately 85 percent of the rebated capacity of RFU facilities deployed through December 31, 2010 was powered by biogas derived from landfills or wastewater treatment facilities.
- Prime movers used at RFU facilities include fuel cells, microturbines, and internal combustion (IC) engines. IC engines have been the dominant prime mover technology of choice up through the reporting period, constituting approximately 14.5 MW (or over 50 percent) of the overall 26.7 MW of rebated 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 cost data prevent the conclusion that there is 90 percent certainty that the mean cost of renewable-powered fuel cells and IC engines is higher than the mean cost of fuel cells and IC engines powered by non-renewable resources.
- RFU facilities have significant potential for reducing GHG emissions. The magnitude of the GHG emission reduction depends significantly on the manner in which the biogas was treated prior to receiving incentives (i.e., the "baseline" condition). RFU facilities that were allowed to vent biogas directly to the atmosphere have a much higher GHG emission reduction potential than RFU facilities which were required to capture and flare biogas.
  - In general, the GHG emission reduction potential for RFU facilities for which flaring biogas was the baseline condition is around 0.5 ton of carbon dioxide equivalent (CO_2eq) per megawatt-hour (MWh) of generated electricity.
  - Conversely, the GHG emission reduction potential for RFU facilities for which venting biogas was the baseline condition is around five 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 is also 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 by displacing natural gas otherwise used to generate process heat.

Conclusions and Recommendations

- California has significant biogas resources that could potentially be used to generate renewable power and reduce GHG emissions. For example, there are over 1,000 landfills, 200 wastewater treatment facilities and thousands of dairies in the state that do not capture and use biogas generated by their operations. Locating RFU systems at these facilities could provide significant GHG emission reductions; help address regional ground water quality issues; serve as new renewable energy generating capacity; and create local jobs and employment. The CPUC should consider investigating the barriers preventing significantly more deployment of RFU facilities under the SGIP and identify the feasibility of taking actions to increase applications of RFU facilities to the SGIP. Among the questions that should be addressed in the investigation include:
  - What is the technical and economic potential for RFU projects in California, identified by source of the biogas (e.g., landfills, wastewater treatment plants; dairies, etc.), prime mover technology (e.g., IC engines, fuel cells; microturbines, etc.) and location.

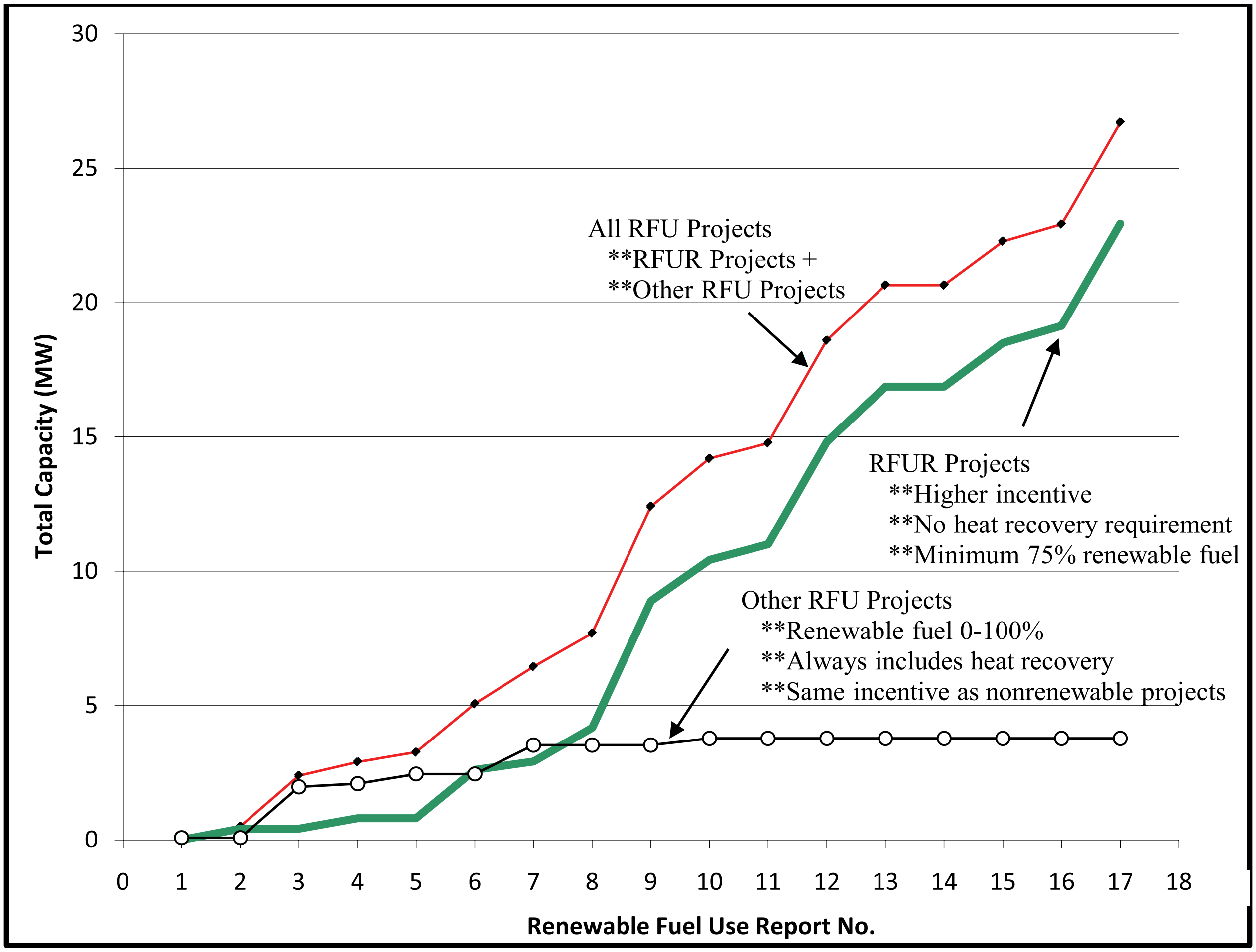
- What are the primary barriers preventing further application and deployment of biogas-to-energy projects in California; and by extension to the SGIP?
- What actions could be reasonably be taken by the PAs or the CPUC to help mitigate the barriers and help increase RFU application and deployment under the SGIP?
- What would be the estimated GHG emission reductions associated with successfully deploying increased levels of RFU facilities and achieving the economic potential?

- The cost breakdown conducted to date on RFU projects does not provide definitive information on the costs of gas clean-up equipment. However, such information is important in determining if there should be differences in incentive levels for RFU projects using biogas fuels. In addition, gas clean-up requirements (and therefore costs) are likely to differ significantly between prime mover technologies (e.g., fuel cells versus microturbines).
  - The CPUC/WG should consider changing the scope of the RFU report to have Itron investigate the information supplied to the PAs on the breakout of gas clean up costs.
  - The CPUC/WG should also consider funding an expanded study on the costs (capital and operating/maintenance costs) of different gas clean-up systems required on different prime movers fueled by biogas. The study should include biogas projects operating outside of the SGIP and California.

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 1–17)

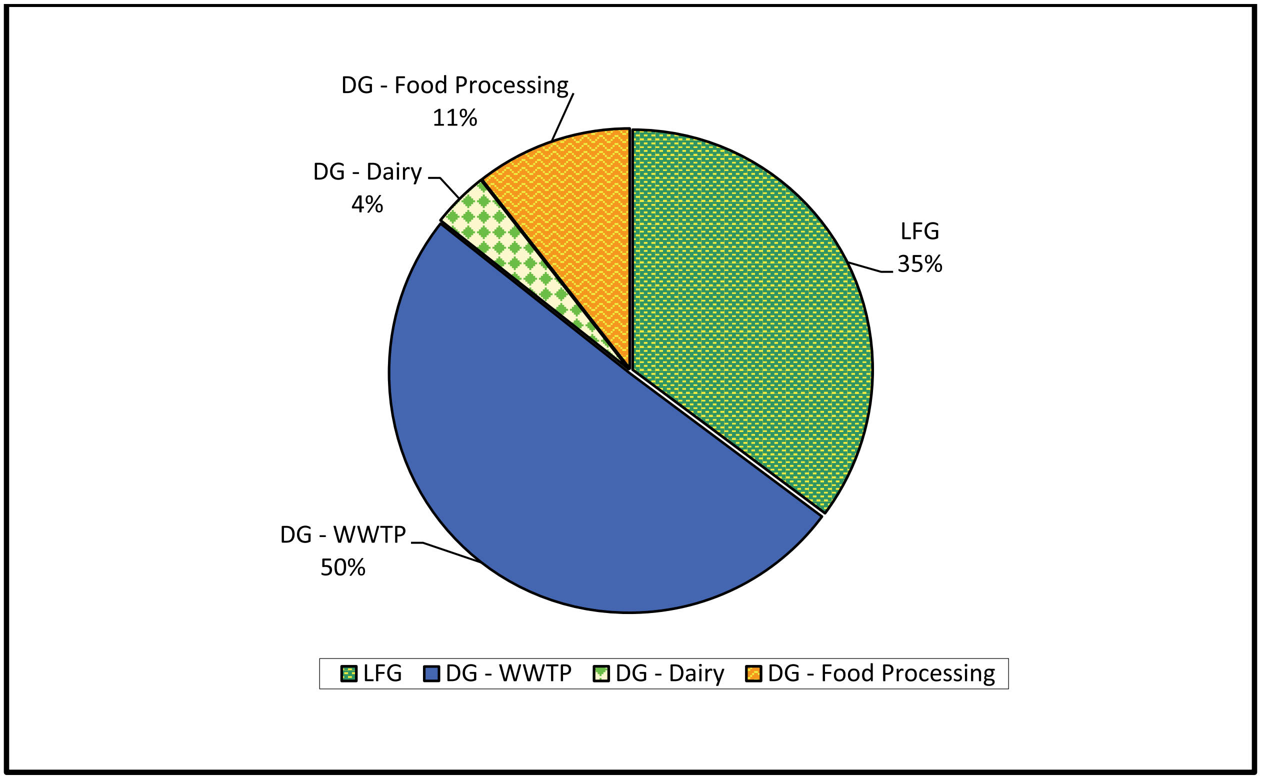


While all RFUR projects are allowed to use as much as 25 percent non-renewable fuel, most operate completely from renewable fuel resources. To date, two-thirds of the RFUR projects have operated solely on renewable fuel. Data were not available for all dual-fuel projects. However, up to and including RFU Report 12, there had been no instances where available data indicated non-compliance with the Program's renewable fuel use requirements. The current report contains five instances of non-compliance with these requirements.[6]

[6] The first instance of non-compliance was in RFU Report #13; this is the fourth report containing instances of non-compliance.

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 3 shows a breakout of RFU projects as of December 31, 2010, by source of biogas (e.g., landfill gas, dairy digester gas, food processing digester gas, etc.) on a rebated capacity basis.[7] It illustrates that just over half of the biogas used in SGIP RFU projects is derived from wastewater treatment plants and approximately a third is derived from landfill gas projects. Dairy digesters provide the smallest contribution at four percent of the total rebated RFU project capacity.

Figure 3: Renewable Fuel Use Project Rebated Capacity by Fuel Type



LFG = landfill gas; WWTP = wastewater treatment plants DG=digester gas

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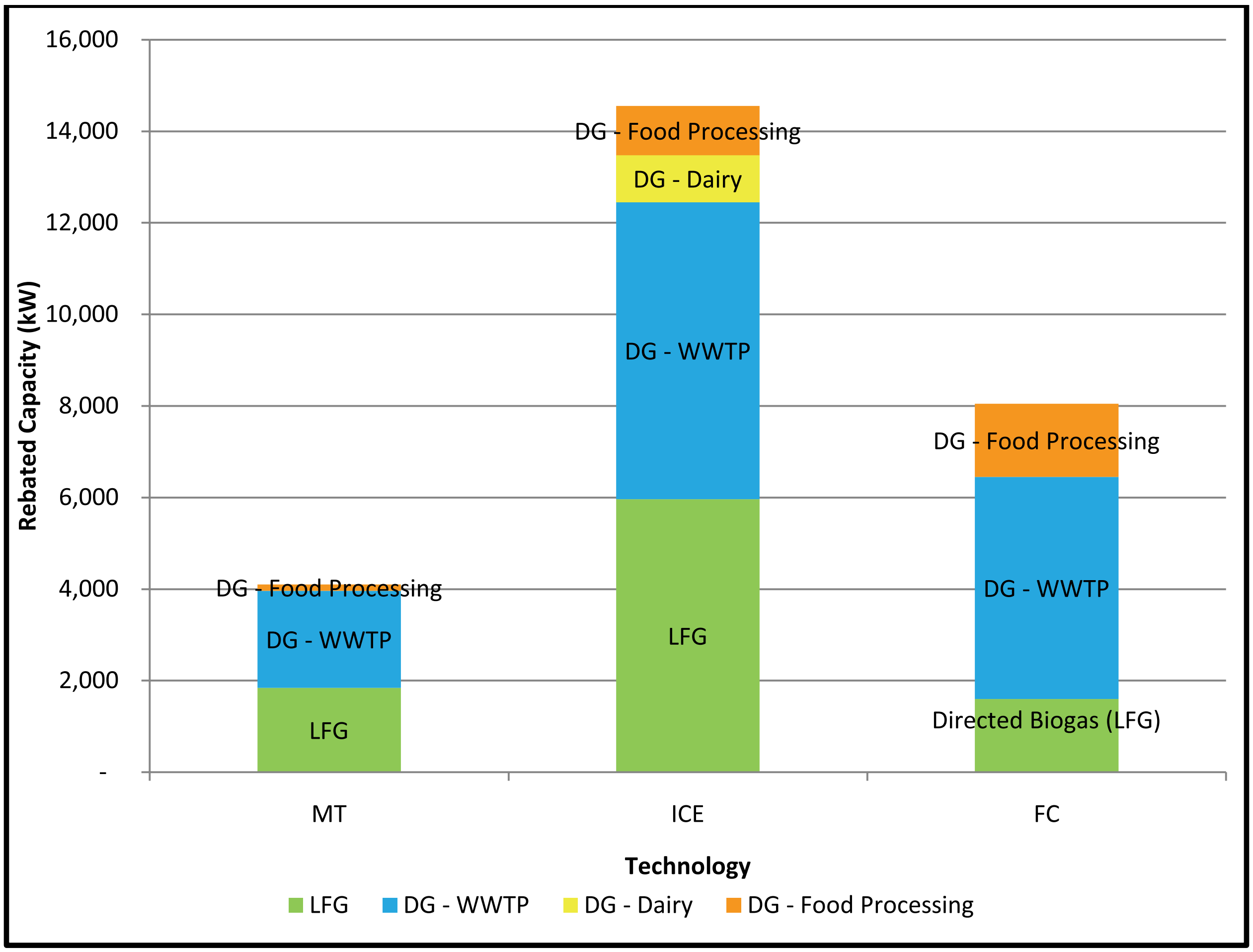
7 For simplicity, digester gas from various sources such as wastes from dairies, wastewater treatment plants, and food processing plants are abbreviated with the prefix for digester gas (DG). For example, DG-dairy refers to biogas derived from anaerobic digesters converting dairy wastes at the dairies.

Figure 4 provides a breakdown of the relative contribution of the different biogas fuels by prime mover technology. Several observations can be made from examining Figure 4. Biogas-powered IC engines, which represent the largest rebated capacity of SGIP RFU facilities, are fueled primarily with biogas derived from landfills and wastewater treatment plants. From a different perspective, Figure 4 shows that dairy digesters use IC engines exclusively for RFU power generation. RFU Report #17 marks the first appearance of LFG-powered fuel cells installed under the SGIP; all of these projects utilize directed biogas. As such, the landfill gas is not literally delivered, but notionally delivered, as the biogas may actually be utilized at any other location along the pipeline route.

Figure 4: Contribution of Biogas Fuel Type by Prime Mover Technology



LFG = landfill gas; WWTP = wastewater treatment plants; MT = micro-turbines; ICE = internal combustion engine; FC = fuel cells; DG = digester gas

Cost Data

Itron also analyzed project cost data available for the *samples* comprising renewable and non-renewable SGIP projects completed to date. Average costs of those sample renewable projects were higher than the average costs of those sample non-renewable projects. However, the combined influence of small sample sizes and substantial variability preclude us from drawing general conclusions about incremental costs likely to be faced by SGIP participants in the future.

Confidence intervals calculated for *populations* comprising both past and future SGIP participants are very large. There was a limited quantity of cost data for fuel cells and IC engines. This limited amount of data increases the uncertainty associated with the mean costs of fuel cells and IC engines. As a result, it is impossible to say with 90 percent confidence that the mean value of the costs of renewable IC engines and fuel cells is any higher than the mean value of the costs of non-renewable IC engines and fuel cells. This counter-intuitive result 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.

2. Summary of Completed RFUR Projects

There were six new RFUR SGIP projects completed during the subject six-month reporting period. A total of 50 RFUR projects had been completed as of December 31, 2010. A list of all SGIP projects utilizing renewable fuel (RFUR and Other RFU) is included as Appendix A.

The 50 completed RFUR projects represent approximately 22.9 MW of installed generating capacity. The prime mover technologies used by these projects are summarized in Table 2. Just more than half (55 percent) of the total rebated RFUR capacity is attributable to IC engines. Fuel cells, an emerging technology, account for close to 30 percent of RFUR project capacity. The average size of microturbine projects is 179 kW, whereas that of renewable-powered fuel cells is 588 kW and that of renewable-fueled IC engines is 633 kW.

Table 2: Summary of Prime Movers for RFUR Projects

Prime Mover	No. Projects	Total Rebated Capacity (kW)	Average Rebated Capacity (kW)*
FC	12	7,050	588
MT	18	3,220	179
IC Engine	20	12,662	633
Total	**50**	**22,932**	**459**

FC = fuel cell; MT = micro-turbine; IC Engine = 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 34 of the 50 RFUR projects recover waste heat. All but two of the 32 digester gas systems include waste heat recovery.[8] Waste heat recovered from digester gas systems is generally used to pre-heat waste water sludge prior to being pumped to digester tanks. Conversely, less than one-quarter of the landfill gas systems include waste heat recovery. In addition, those 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.[9]

[8] In several RFU reports up to and including RFU Report #15 three (3) projects were incorrectly reported as not including heat recovery. This error resulted from misinterpretation of contents of Installation Verification Inspection Reports.

[9] 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 5 shows the total capacity for each year by year. The peak installation for internal combustion engines was 2006 for a total capacity of 5MW. The 2010 fuel cell capacity is for the directed biogas projects that came on line.

Figure 5: Total Capacity per Year for Each Technology

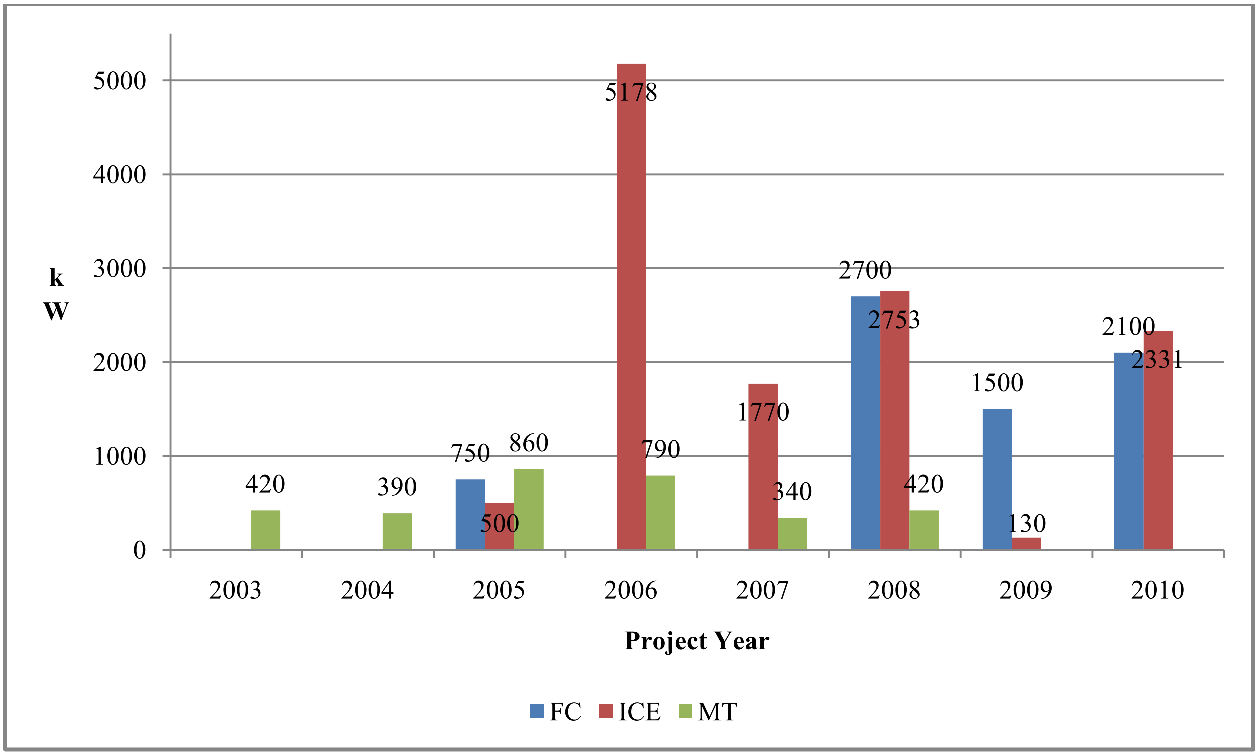


Table 3: Summary of Waste Heat Recovery Incidence by Type of Renewable Fuel for RFUR Projects

Renewable Fuel Type	No. of Sites	Sites With Heat Recovery	Sites Without Heat Recovery
Digester Gas	32	30	2
Landfill Gas	18	4	14
Total	**50**	**34**	**16**

3. Fuel Use at RFUR Projects

While all RFUR projects could use as much as 25 percent non-renewable fuel, 33 of the 50 total RFUR projects operate completely from renewable fuel resources. Determining compliance with renewable fuel use requirements is tied to warranty status. In particular, the period during which RFUR projects are subject to the non-renewable fuel use requirement is specified in the SGIP contracts between the host customer, the system owner, and the PAs. In turn, the length of time the RFUR facility is subject to the renewable fuel use requirement is the same as the equipment warranty requirement. 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. The SGIP applicant must provide warranty (and/or maintenance contract) start and end dates in the Reservation Confirmation and Incentive Claim Form.

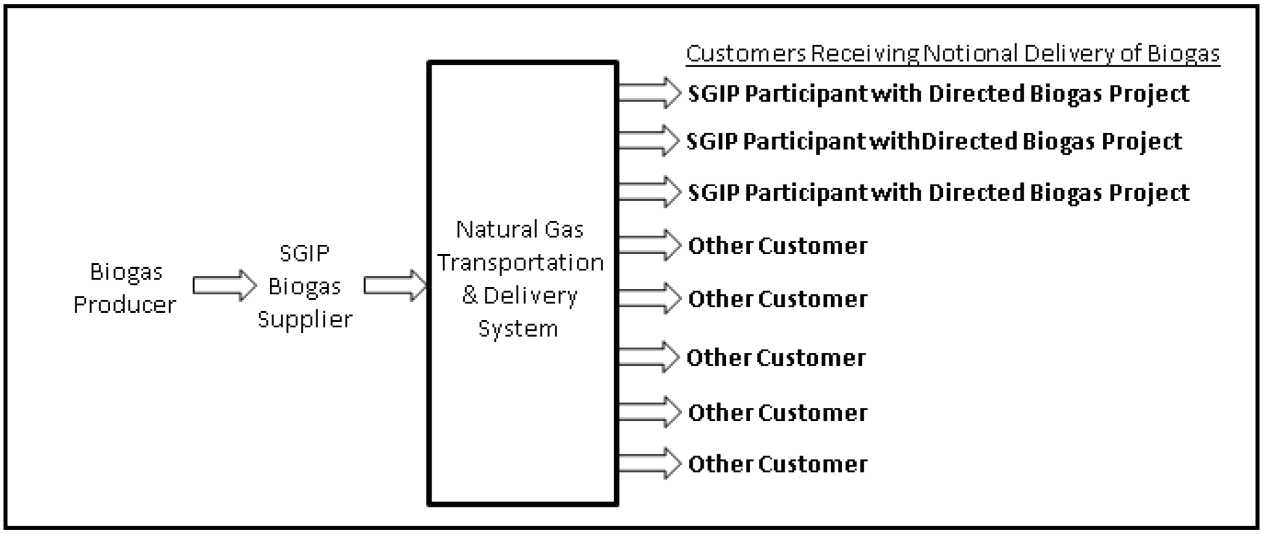
For RFU Reports #1 through #16 RFU facilities were grouped into two categories in assessing renewable fuel use compliance:

- "Dedicated" RFU facilities located where biogas is produced (e.g., wastewater treatment facilities; landfill gas recovery operations, etc.) and the biogas is the only fuel source used for powering the RFU system; and
- "Blended" RFU facilities located where biogas is produced that use a blend of biogas and fossil fuel (e.g., natural gas).

For RFU facilities located where the biogas was produced and acted as the only fuel source for the RFU system, the facility was automatically in compliance. For RFU facilities using a blend of fuels, assessing compliance required information on the amount of biogas consumed relative to the amount of non-biogas consumed on-site. It is not possible to use the same method in assessing compliance of directed biogas projects as that used for assessing compliance of "blended" RFU projects. In "blended" RFU 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% of the total annual energy input to the RFU facility. However, in directed biogas RFU 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 and subsequent allocation to customers that may or may not be SGIP participants. The left side of Figure 6 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 6 must be in balance.

Figure 6: 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 4. The properties at the extraction point represent a significant departure from conditions encountered to date for Dedicated and Blended RFU facilities. 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.

Table 4: 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. The following information will be needed for each directed biogas project which is required to comply with renewable fuel use requirements:

1. Renewable fuel invoices for each individual SGIP directed biogas project. If an invoice covers more than one SGIP RFU facility then the total quantity of directed biogas purchased must be allocated to individual facilities.
2. Renewable fuel invoice information for directed biogas sales outside of the SGIP (if applicable).
    a. Applicable only if a SGIP directed biogas project and a project outside of the SGIP are serviced by the same biogas meter.
    b. Identification by name of customers outside of the SGIP is not requested.
3. Fuel metering information that identifies the source, quality magnitude (i.e., Btu/scf), quality basis (i.e., HHV or LHV), and amount of biogas associated with all purchases covered by renewable fuel invoices.

Fuel supply and contract status for RFUR projects are summarized in Table 5. Only 19 of the total 50 RFUR projects had active warranty status. Thirty-one RFUR projects (or nearly two-thirds of all RFUR projects) had an expired warranty status. Of the 19 RFUR sites with active warranties, seven operated solely on renewable fuel. By definition, all seven of those RFUR projects are in compliance with SGIP renewable fuel use requirements.

Table 5: Summary of Fuel Supplies and Warranty Status for RFUR Projects

	Warranty/Renewable Fuel Use Requirement Status[10]					
	Active		Expired		Total	
Fuel Supply	No. Projects (n)	Rebated Capacity (kW)	No. Projects (n)	Rebated Capacity (kW)	No. Projects (n)	Rebated Capacity (kW)
Renewable only	7	4,944	26	8,350	33	13,294
Non-renewable & onsite renewable	8	5,390	5	2,648	13	8,038
Non-renewable & offsite, directed renewable	4	1,600	0	0	4	1,600
Total	**19**	**11,934**	**31**	**10,998**	**50**	**22,932**

In addition, Table 5 shows that 33 of the total 50 RFUR sites (both those with expired or active warranties) obtain 100 percent of their fuel from renewable resources. Information on fuel use for the remaining 17 dual-fueled projects (both active and expired) is as follows.

Dual-fueled RFUR Projects In Compliance

During this reporting period, one of the dual-fueled projects was found to be in compliance with SGIP renewable fuel use requirements based on analysis of metered data. For this project biogas consumption data were available for part of the year only, so for the rest of the year it was necessary to make engineering estimates.

- **PG&E A-1749.** This 130 kW IC engine system came on-line in November 2009. The system uses renewable fuel from a wastewater treatment plant digester and recovers waste heat from the engine to preheat the digester sludge. The host customer provided natural gas usage for the period from January 1, 2010 to November 30, 2010, and biogas usage for the period from January 1, 2010 to June 30, 2010. The contribution of non-renewable fuel for the period where biogas and natural gas data were available was 6 percent. For the remainder of 2010, the host customer reported that the biogas meter was inoperative and therefore compliance was calculated based on electrical generation (assuming a conversion efficiency of 18 percent based on Q1-Q2 performance) and natural gas consumption. For the period from July 1, 2010 to November 30, 2010, this site was found to be using no more than 9 percent non-renewable fuel, and is therefore determined to be in compliance with SGIP fuel use requirements.

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10 Project-specific warranty start dates and lengths are not readily available. Consequently, for reporting purposes all warranties are assumed to be the minimum required length and start on the incentive payment date.

Dual-fueled RFUR Projects Not In Compliance

Five projects were found to be using more non-renewable fuel than allowed on an annual fuel input basis. For all of these projects it was necessary to estimate electrical conversion efficiency because metered biogas consumption data were not available.[11]

- **PG&E A-1490**. This 600 kW fuel cell project came on-line in April 2008. Metered electric generation and natural gas consumption data were obtained from the SGIP participant. Biogas use is metered by the participant. However, because some biogas data were missing, the data could not be used for compliance evaluation purposes. Itron assumed an electrical conversion efficiency to estimate total fuel use during periods of electricity generation.[11] Based on these estimates, Itron believes natural gas usage during the current reporting period exceeded 54 percent of the total annual fuel input and the system was not in compliance with SGIP renewable fuel use provisions.
- **SCE PY06-062.** This 900 kW fuel cell system came on-line in March 2008. The system is located at a wastewater treatment facility and utilizes renewable fuel produced by a digester system. Metered electric generation and natural gas consumption data were obtained from the SGIP participant. However, because some biogas data were missing, the data could not be used for compliance evaluation purposes. Itron assumed an electrical conversion efficiency to estimate total fuel use during periods of electricity generation.[11] Based on these estimates, Itron believes natural gas usage during the current reporting period exceeded 32 percent of the total annual fuel input. The system was not in compliance with SGIP renewable fuel use provisions for this reporting period.
- **SCG 2006-036.** This 1200 kW fuel cell system came on-line in October 2008 and is located at a wastewater treatment facility and utilizes renewable fuel produced by a digester system. A fuel blending system controls the mix of renewable and non-renewable fuel. Metered electric generation and natural gas consumption data were obtained from the SGIP participant. In addition the participant is monitoring biogas usage. However, because some biogas data were missing, the data could not be used for compliance evaluation purposes. Itron assumed an electrical conversion efficiency to estimate total fuel use during periods of electricity generation.[11] Based on these estimates, Itron believes natural gas usage during the current reporting period exceeded 73 percent of the total annual fuel input. The system was not in compliance with SGIP renewable fuel use provisions for this reporting period.

[11] In these calculations an electrical conversion efficiency of 33 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 33 percent (which is likely), then the actual non-renewable fuel use is higher than the estimated percent.

- **SCG 2006-012.** This 900 kW fuel cell project came online 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 received metered electric generation and natural gas consumption data from the SGIP participant. In addition the participant is monitoring biogas usage. However, because some biogas data were missing, the data could not be used for compliance evaluation purposes. Itron assumed an electrical conversion efficiency to estimate total fuel use during periods of electricity generation.[11] Based on these estimates, the natural gas usage during the current reporting period exceeded 66 percent. The system was not in compliance with SGIP renewable fuel use provisions for this reporting period.
- **SCG 2008-003.** This 600 kW fuel cell project came online 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. These digesters are provided sewage sludge and fat, oil, and grease as feedstock. 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. Metered electric generation and natural gas consumption data were obtained from the SGIP participant. In addition, the participant is monitoring biogas usage. However, because some biogas data were missing, the data could not be used for compliance evaluation purposes. Itron assumed an electrical conversion efficiency to estimate total fuel use during periods of electricity generation.[11] Based on these estimates, the natural gas usage during the current reporting period exceeded 47 percent. The system was not in compliance with SGIP renewable fuel use provisions for this reporting period.

Dual-Fueled RFUR Project Compliance Status Not Applicable

A dual-fueled RFUR project is assigned compliance status "Not Applicable" if it has not yet been operational for a complete calendar year, or if its warranty has expired. The following is a summary of sites that fall into either of these categories.

Not Yet Operational for a Complete Calendar Year

- **SDREO-0351-07.** This 560 kW IC engine system is located at a waste water treatment facility and utilizes the anaerobic digester gas from five digesters on-site to provide baseload electric power to the treatment facility. When sufficient digester gas is not available to run this system at full load, natural gas is mixed in. Electrical output, natural gas consumption, and digester gas consumption data are being collected by the host customer and were provided to Itron for the period from July 1, 2010 to December 31, 2010. Based on the data provided, the natural gas usage during the six month period observed did not exceed 2 percent. If this trend continues through a complete calendar year the project will be in compliance with SGIP renewable fuel use requirements.

- **PG&E 1802.** This 400 kW fuel cell project utilizes 75% directed biogas from a landfill in Pennsylvania and 25% natural gas. The system became operational in December of 2010 and therefore is not required to comply with SGIP renewable fuel use requirements yet.
- **PG&E 1812.** This 400 kW fuel cell project utilizes 75% directed biogas from a landfill in Pennsylvania and 25% natural gas. The system became operational in November of 2010 and therefore is not required to comply with SGIP renewable fuel use requirements yet.
- **PG&E 1811.** This 400 kW fuel cell project utilizes 75% directed biogas from a landfill in Pennsylvania and 25% natural gas. The system became operational in November of 2010 and therefore is not required to comply with SGIP renewable fuel use requirements yet.
- **PG&E 1810.** This 400 kW fuel cell project utilizes 75% directed biogas from a landfill in Pennsylvania and 25% natural gas. The system became operational in November of 2010 and therefore is not required to comply with SGIP renewable fuel use requirements yet.
- **SCE PY10-002.** This project is a 750 kW fuel cell system consisting of three 250 kW stacks, of which only two are rebated through the SGIP. The system is located on 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. The system became operational in October of 2010 and therefore is not required to comply with SGIP renewable fuel use requirements yet.

Warranty Expired

- **SCE PY03-092.** This 500 kW fuel cell project uses natural gas for backup fuel supply and piloting purposes. The fuel cell system is composed of two molten carbonate fuel cells, each of which is rated for 250 kW of electrical output. Renewable fuel used by this system is produced as a by-product of a municipal wastewater treatment process. A natural gas metering system has been installed by SCG to monitor natural gas usage. Biogas use is not metered. In December of 2010 the fuel cells were removed and decommissioned after the warranty period had lapsed. During the period when data were provided and the system was under contract the actual contribution of non-renewable fuel never exceeded 25 percent on an annual fuel input basis.
- **SCE PY03-017.** This IC engine system was designed to use natural gas for back-up and piloting purposes. The SGIP participant provided metered electric generation, biogas consumption, and natural gas consumption data for previous reporting periods. However, in Q2 2008 the participant's SGIP contract reached the end of its term and data were no

longer available from this participant. During the period when data were provided and the system was under contract the actual contribution of non-renewable fuel never exceeded 25 percent on an annual fuel input basis.

- **SCE PY04-158 and SCE PY04-159.** These two systems are located at the same wastewater treatment facility and utilize renewable fuel produced by the same digester system. The two projects are grouped together here because they share a common fuel blending system. The fuel blending system controls the mix of renewable and non-renewable fuel. In the second quarter of 2008 the participant's SGIP contract reached the end of its term and no metered data have been available to assess the actual fuel mix since this time. In SCE's September 2006 installation verification inspection reports, the participant reported that the systems were using 80 percent digester gas and 20 percent natural gas.[12]
- **PG&E A-1313**. This 240 kW system consists of eight 30 kW microturbines installed at a wastewater treatment facility and uses heat recovered from the system to warm the digesters. Metered daily electric generation, biogas consumption, and natural gas consumption data were obtained from the SGIP participant for this microturbine system. The system was off for the previous reporting period and is currently down for repair.

Overall (renewable-only and dual-fuel), eight (62 percent) of the 13 RFUR projects remaining under warranty for which renewable fuel use compliance is applicable during this reporting period comply with the SGIP 25 percent non-renewable requirement.

[12] In prior RFU Reports, Itron had proposed installing natural gas metering at this project to verify that the non-renewable fuel consumption remained below 25 percent of annual fuel use. However, after researching natural gas meters and installation practices, Itron found that installing a natural gas meter would require the facility to temporarily shut down their natural gas line, purge the line and install a T-valve before installing a gas meter. For safety and cost reasons, this was not found to be feasible.

A summary of renewable fuel use compliance for the 17 dual-fuel systems is presented in Table 6.

Table 6: Fuel-Use Compliance of Dual-Fueled RFUR Projects (Projects Utilizing Non-Renewable Fuel)

PA Project ID No	PA/ Incentive Level	Technology/ Renewable Fuel Type	Capacity (kW)	Operational Date*	Annual Natural Gas Energy Flow (MM Btu) †	Renewable Fuel Use (% of Total Energy Input)	SGIP Warranty Status	Meets Program Renewable Fuel Use Requirements? ‡
1749	PG&E / Level 3-R	ICE/ DG - WWTP	130	11/9/2009	373	95	Active	Yes
1490	PG&E / Level 2	FC / DG - WWTP	600	4/24/2008	23,051	46	Active	No
PY06-062	SCE / Level 2	FC / DG - WWTP	900	3/4/2008	14,981	68	Active	No
2006-036	SCG / Level 2	FC / DG WWTP	1200	10/27/2008	16,760	27	Active	No
2006-012	SCG/ Level 2	FC / DG - WWTP	900	12/18/2009	22,091	34	Active	No
2008-003	SCG / Level 2	FC / DG – food processing	600	12/14/2009	15,091	53	Active	No
0351-07	CCSE / Level 2	ICE / DG - WWTP	560	4/16/2010	4,346 ‖	98 ‖	Active	Not Applicable ‡‡
1802	PG&E / Level 2	FC / Directed Bio Gas (Landfill)	400	12/22/2010	Not Available ‖	Not Available ‖	Active	Not Applicable ‡‡
1812	PG&E / Level 2	FC / Directed Bio Gas (Landfill)	400	11/10/2010	Not Available ‖	Not Available ‖	Active	Not Applicable ‡‡
1811	PG&E / Level 2	FC / Directed Bio Gas (Landfill)	400	11/10/2010	Not Available ‖	Not Available ‖	Active	Not Applicable ‡‡
1810	PG&E / Level 2	FC / Directed Bio Gas (Landfill)	400	11/10/2010	Not Available ‖	Not Available ‖	Active	Not Applicable ‡‡
PY10-002	SCE / Level 2	FC / DG - WWTP	500	10/31/2010	Not Available ‖	Not Available ‖	Active	Not Applicable ‡‡
PY03-092	SCE / Level 1	FC / DG - WWTP	500	3/11/2005	Decommissioned	Decommissioned	Expired	Not Applicable
PY03-017	SCE / Level 3-R	ICE / DG - WWTP	500	5/11/2005	Not Available	Not Available	Expired	Not Applicable
PY04-158	SCE / Level 3-R	ICE / DG - WWTP	704**	10/25/2006 ††	Not Available	Not Available	Expired	Not Applicable
PY04-159	SCE / Level 3-R	ICE / DG - WWTP	704	10/26/2006	Not Available	Not Available	Expired	Not Applicable
1313	PG&E / Level 3-R	MT / DG - WWTP	240	3/6/2007	Not Available	Not Available	Expired	Not Applicable

* 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 December 31, 2010. The basis is the lower heating value (LHV) of the fuel.

‡ SGIP renewable fuel use requirements are not applicable to projects no longer under warranty

|| Due to this project's operational date, a full year of metered data necessary to calculate estimates of natural gas energy use were not available for this reporting period.

** In RFU Reports #9 and #10 this project's size was reported as 296 kW. That was the capacity used in incentive calculations. The actual physical size of the system is 704 kW. In this particular circumstance, there were two separate applications, both 704 kW of physical capacity, for a total combined capacity of 1,408 kW. The maximum total incentive is one MW. As a result, one application was rebated in full (rebated capacity of 704 kW) while the second application was rebated up to the remainder of the eligible kW (296 kW). The result was a much lower value for rebated capacity than physical capacity.

†† In RFU Reports #9 through #13 this project's Operational Date was incorrectly reported as 11/15/2005. That date is an estimate of when the system began operating. For this report the basis of Operational Date values is incentive payment date as described above in footnote 13.

‡‡ This site did not become operational until mid-to-late 2010, thus the issue of compliance is not yet applicable.

4. Greenhouse Gas Emissions Impacts

Due to increased interest in the GHG emission aspects of biogas projects,[4] information regarding GHG emission impacts is presented in this section. The GHG emission information presented here was previously presented in the SGIP Ninth-Year Impact Evaluation Final Report.[13] Additionally, key factors that could influence GHG emission impacts from renewable fuel projects in the future are discussed.

Table 7 presents the capacity-weighted average GHG emission results developed for the SGIP Ninth-Year Impact Evaluation Final Report. For this RFU report, these averages have been augmented with information on the ranges of site-specific results which underlie the averages. Results in Table 7 suggest two important observations. First, the assumed baseline for the biogas (i.e., whether the biogas was vented to the atmosphere or flared) is the most influential determinant of GHG emission impacts.[14] 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. Second, other factors are responsible for relatively small amounts of site-to-site variability in impact estimates calculated for 2009.

Table 7: Summary of CO_2 Emission Impacts from SGIP Biogas Projects in 2009

Baseline Biogas Assumption	Prime Mover Technology	Annual CO_2eq Impact Factor	
		Capacity-Weighted Average (Tons/MWh)	Range of Site-Specific Results (Tons/MWh)
Flare	FC	-0.40	-0.38 to -0.40
	MT	-0.41	-0.39 to -0.54
	IC Engine	-0.50	-0.40 to -0.60
Vent	IC Engine	-4.41	-4.38 to -4.41

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

[13] GHG Information from the SGIP Ninth-Year Impact Evaluation Final Report was used here because this evaluation contains the most recent GHG estimates of the SGIP. The SGIP annual Impact Evaluation reports have included information about GHG emissions impacts starting with the 2005 report. All SGIP measurement and evaluation reports, including the Impact Evaluation reports, are available for download from the CPUC website (http://www.cpuc.ca.gov/PUC/energy/DistGen/sgip/sgipreports.htm)

[14] 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).

Simplifying assumptions underlying the above results include:

- Heat recovered from RFUR projects was used to satisfy heating load that otherwise would have been satisfied using biogas (e.g., in a boiler)[15]
- Estimates for GHG reductions from biogas projects were based solely on estimates of the methane content in the used biogas and did not take into account natural gas used by the biogas facilities
- A single representative electrical conversion efficiency was assumed for each technology

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.[16] At the state level, the California Air Resources Board (CARB) provides guidelines for control of methane and other volatile organic compounds from biogas facilities.[17] At the federal level, New Source Performance Standards and Emission Guidelines regulate methane capture and use.[18]

Biogas baseline assumptions used to calculate GHG impact estimates for 2007-2009 were based on previous studies.[19] [20] 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 Impact Evaluation the biogas baseline was modified for WWTP and food processing SGIP projects smaller than 150 kW.

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15 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).

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

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

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

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

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

The evolution of biogas baseline assumptions is summarized in Table 8.

Table 8: Biogas Baseline Assumptions

<table>
<tr><th rowspan="2">Renewable Fuel Source</th><th rowspan="2">Facility Type*</th><th rowspan="2">Size of Rebated System (kW)</th><th colspan="2">Impact Evaluation</th></tr>
<tr><th>2007-2008</th><th>2009</th></tr>
<tr><td rowspan="5">Digester Gas</td><td rowspan="2">WWTP</td><td><150</td><td>Vent</td><td rowspan="4">Flare</td></tr>
<tr><td>≥150</td><td>Flare</td></tr>
<tr><td rowspan="2">Food Processing</td><td><150</td><td>Vent</td></tr>
<tr><td>≥150</td><td>Flare</td></tr>
<tr><td>Dairy</td><td>All Sizes</td><td>Vent</td><td>Vent</td></tr>
<tr><td>Landfill Gas</td><td>LFG</td><td>All Sizes</td><td>Flare</td><td>Flare</td></tr>
</table>

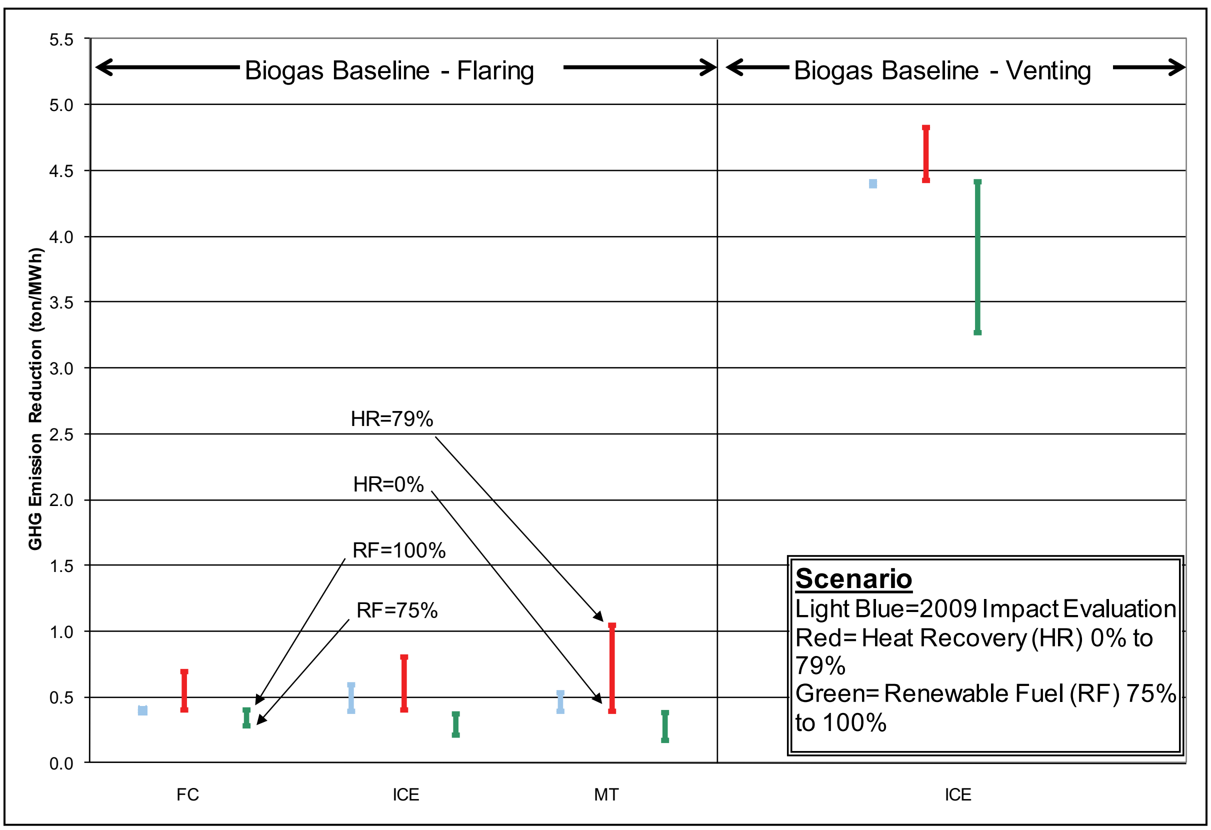
* WWTP = Waste Water Treatment Plant; LFG = Landfill Gas

In addition, two hypothetical scenarios were developed to help illustrate the influence of heat recovery and natural gas usage on GHG emission reductions at sites relying mainly or solely on biogas. The first scenario examined the influence of heat recovery on GHG emission reductions. For this scenario, the heat recovery rate was allowed to range from zero percent to 79 percent[21] of the input energy remaining after accounting for any generated electricity. The second scenario examined the effect on GHG emissions associated with reducing the renewable fuel usage and consequently increasing the non-renewable fuel usage. The range of renewable fuel for this scenario ranged from 75 percent to 100 percent because the SGIP requires RFUR projects to limit use of non-renewable fuel to 25 percent (i.e., 75 percent renewable fuel minimum).

[21] Seventy-nine percent was assumed as a practical maximum heat recovery rate.

Figure 7 shows the GHG emission reductions associated with these hypothetical scenarios compared to the 2009 Impact Evaluation GHG emission reduction range. As shown, both scenarios could introduce much greater variability in GHG emission reductions than the 2009 Impact Evaluation GHG emission reduction range due to variability in actual heat recovery or renewable fuel usage rates. However, the most influential factor on GHG emission reductions still remains the biogas baseline. At any given point on the heat recovery bar (shown in red below), variances by technology and biogas baseline are due to the differences in assumed electrical conversion efficiency rates. The variability associated with the renewable fuel bar (shown in green below) in a venting baseline scenario is greater than it is in the flaring baseline scenario because the global warming potential of venting CH_4 is much higher than it is for flaring CH_4. Note that the baseline condition of a biogas project is not controllable; it is a condition tied to existing business practices and regulations. Consequently, a venting baseline provides greater GHG emission reduction potential simply because there is more un-captured methane being released to the atmosphere than if the biogas had been captured and flared.

Figure 7: Emission Reduction Scenarios



5. Cost Comparison between RFU and Other Projects

Incentive levels for renewable fuel projects have changed over time and are roughly defined as below for the purposes of this report:[22]

- Incentive Level 1: Originally an incentive level for PV, wind, and fuel cells powered by renewable fuels
- Incentive Level 2: Fuel cells powered by renewable fuels
- Incentive Level 3: Used for a short time following the Program's inception to designate microturbines, IC engines, and small gas turbines using renewable fuels
- Incentive Level 3-R: Microturbines, IC engines, and small gas turbines using renewable fuels
- Incentive Level 3-N: Microturbines, IC engines, and small gas turbines using non-renewable fuels

Beginning in September 2002, RFUR projects were eligible for a higher incentive level than non-renewable projects. 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 Level 3-R project costs could fall below Level 3 costs as Level 3-R projects are exempt from waste heat recovery requirements. As a result, Level 3-R 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 Level 3 and Level 3-R project costs.

[22] Itron has moved away from using incentive levels in the annual Impact Evaluation reports because of the confusion caused by changes in the incentive levels. Incentive levels are reported here only because of the manner in which incentive levels were used to designate RFUR classification.

It is possible to use historical SGIP project cost data to examine fuel treatment and heat recovery costs faced by SGIP participants. Eligible installed costs for all fuel cell, microturbine, and IC engine projects operational as of December 31, 2010, are summarized in Table 9. 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 for which summary statistics are presented in Table 9 comprise only a few projects. In these instances the sample sizes play a very important role in determining ability to draw general conclusions from the data. The combined influence of sample size and sample variability on the inferential statistics is discussed below in the section titled *Uncertainty Analysis*.

Table 9: 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	Yes	Yes	8	4.51 – 11.00	9.41	8.04	2.34	7.45
	Yes	No	0	---	---	---	---	---
	Yes	Yes or No	8	4.51 – 11.00	9.41	8.04	2.34	7.45
	No	Yes	23	5.06 - 18.00	8.53	8.74	3.10	7.81
	DBG	No	4	10.80 - 13.00	13.00	12.40	1.12	12.45
IC Eng-ine	Yes	Yes	18	1.08 - 5.70	2.76	2.80	1.20	2.83
	Yes	No	2	1.71 - 2.87	2.29	2.29	0.82	2.71
	Yes	Yes or No	20	1.08 - 5.70	2.76	2.76	1.16	2.82
	No	Yes	229	0.85 - 10.70	2.30	2.60	1.33	2.30
MT	Yes	Yes	8	2.26 - 11.30	3.99	5.13	2.69	4.55
	Yes	No	10	1.23 - 5.39	3.61	3.47	1.27	2.89
	Yes	Yes or No	18	1.23 - 11.30	3.75	4.40	2.30	3.78
	No	Yes	120	0.70 – 8.40	3.23	3.35	1.32	3.24

FC = fuel cell; MT = microturbine; IC engine = 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 7 by identifying those using any amount of renewable fuel as a "Yes" classification.

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

Heat Recovery Equipment Costs

All of the projects using renewable fuel include fuel-conditioning equipment. Most of the renewable fuel projects include heat recovery even though most of them were not required to. Differences observed between the average costs of these two groups could be due to the difference in provisions for heat recovery. For example, the heat recovery difference for microturbines ($1.66) is calculated as $5.13 minus $3.47.

$$\Delta Heat\,\mathrm{Re}\,\mathrm{cov}\,ery = \left(\frac{RFU}{w/\,HR}\right) - \left(\frac{RFU}{w/\,o\,HR}\right) \qquad \textbf{Equation 1}$$

Where

RFU = renewable fuel use

HR = heat rate

w/ = with

w/o = without

Table 10: 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	Yes	Yes	8	4.51 - 11.00	9.41	8.04	2.34	7.45
IC Engine	Yes	Yes	18	1.08 - 5.70	2.76	2.80	1.20	2.83
	Yes	No	2	1.71 - 2.87	2.29	2.29	0.82	2.71
	Increase due to Heat Recovery				0.47	0.51	0.38	0.12
MT	Yes	Yes	8	2.26 - 11.30	3.99	5.13	2.69	4.55
	Yes	No	10	1.23 - 5.39	3.61	3.47	1.27	2.89
	Increase due to Heat Recovery				0.38	1.66	1.42	1.66

The mean costs for heat recovery is higher than non-heat recovery systems. However, based on the relatively small number of projects, there is no statistical difference in cost.

Fuel Treatment Equipment Costs

All of the non-renewable fuel projects include heat recovery equipment. Many of the renewable fuel projects include heat recovery even though most of them were not required to. Any difference observed between the costs of these two groups could be due to the difference in provisions for fuel treatment (which is usually, but not always, limited to gas clean-up such as removal of hydrogen sulfide). For example, the fuel treatment difference for IC engines ($0.20) is calculated as $2.80 minus $2.60.

$$\Delta Fuel\,Treatment = \left(\frac{RFU}{w/HR}\right) - \left(\frac{NG}{w/HR}\right) \qquad \textbf{Equation 2}$$

Where

NG = natural gas

Table 11: Cost Effect of Renewable Fuel Use

				$/Watt Eligible Installed Costs				
Tech	**Includes Renewable Fuel?**	**Includes Heat Recovery?**	**No. Projects**	**Range**	**Median**	**Mean**	**Std. Dev.**	**Size-Wtd. Avg.**
FC	Yes	Yes	8	4.51 - 11.00	9.41	8.04	2.34	7.45
	No	Yes	23	5.06 - 18.00	8.53	8.74	3.10	7.81
	Increase due to RFU				0.88	(0.70)	(0.76)	(0.36)
IC Engine	Yes	Yes	18	1.08 - 5.70	2.76	2.80	1.20	2.83
	No	Yes	229	0.85 - 10.70	2.30	2.60	1.33	2.30
	Increase due to RFU				0.46	0.20	(0.13)	0.53
MT	Yes	Yes	8	2.26 - 11.30	3.99	5.13	2.69	4.55
	No	Yes	120	0.70 - 8.40	3.23	3.35	1.32	3.24
	Increase due to RFU				0.76	1.78	1.37	1.31

The analysis indicates there is a statistically significant difference in cost between the technology types but no statistically significance difference in cost within the technologies for the project in the program. The increased cost of using a renewable fuel includes gas collection and processing. Our data does not indicate that this is a significant increase to the fuel cost.

RFU Equipment Costs

All of the non-renewable fuel projects include heat recovery equipment. 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 different SGIP requirements. For example, the RFU difference for IC engines ($0.16) is calculated as $2.76 minus $2.60.

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

Uncertainty Analysis

Project cost data are available for all completed projects. The sampling error included in difference of means results calculated for projects completed in the past is zero because project cost data are available for all of these projects. However, the key question faced by the CPUC and other Program designers is:

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 more difficult to answer. 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.

Cost comparison discussions for microturbines, IC engines, and fuel cells are presented below. Difference of means results are augmented with 90 percent confidence intervals about these means. In each of these cases the confidence intervals are based on the sample statistics (e.g., n, mean, and std. dev.) presented in Table 9.

Microturbine Project Cost Comparisons

Cost comparison results for microturbines are summarized in Table 12. These data show, for instance, that the average incremental cost associated with presence of heat recovery was $1.66 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.[23]

Table 12: Microturbine Project Cost Comparison Summary

Physical Difference	Difference of Means ($/Watt)	90% Confidence Interval ($/Watt)
Heat Recovery	1.66	0.07 to 3.25
Fuel Treatment	1.78	1.05 to 2.51
RFU	1.05	0.47 to 1.63

The 90 percent confidence intervals presented in Table 12 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 just seven cents per watt. This counterintuitive result implies that systems without heat recovery might be nearly the same cost as 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.

[23] 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.

IC Engine Project Cost Comparisons

Cost comparison results for IC engine projects are summarized in Table 13. The differences between means are small in comparison to the variability exhibited by past costs of renewable fuel projects. This variability, combined with relatively small numbers of renewable fuel projects, results in very large confidence intervals.

Table 13: IC Engine Project Cost Comparison Summary

Physical Difference	Difference of Means ($/Watt)	90% Confidence Interval ($/Watt)
Heat Recovery	0.51	-1.00 to 2.02
Fuel Treatment	0.20	-0.31 to 0.71
RFU	0.16	-0.33 to 0.65

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 14. Results for the incremental difference due to heat recovery are not presented because all 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 technology and the small number of facilities.

Table 14: Fuel Cell Project Cost Comparison Summary

Physical Difference	Difference of Means ($/Watt)	90% Confidence Interval ($/Watt)
Heat Recovery	---	---
Fuel Treatment	-0.70	-3.13 to 1.49
RFU	-0.70	-3.13 to 1.49

Cost Comparison Summary

Comparison of the installed costs between renewable- and non-renewable-fueled generation systems operational as of December 31, 2010, 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. 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 15. 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 (34 percent) is also equipped with a non-renewable fuel supply. These projects are identified in the "Any Non-Renewable Fuel Supply?" column.

Table 15: SGIP Projects Utilizing Renewable Fuel

PA Project ID No.	PA/ Incentive Level	Technology/ Renewable Fuel Type	Capacity (kW)	Operational Date*	RFUR Project?	Any Non-Renewable Fuel Supply?
0007-01	CCSE/ Level 3	MT/ DG - WWTP	88	8/30/2002	No	No
PY02-055	SCE/ Level 3-R	MT/ Landfill gas	420	4/18/2003	Yes	No
PY01-031	SCE/ Level 3	ICE/ Landfill gas	970	9/29/2003	No	No
110	PG&E/ Level 3	ICE/ DG - WWTP	900	10/23/2003	No	Yes
PY02-074	SCE/ Level 3-R	MT/ Landfill gas	300	2/12/2004	Yes	No
0026-01	CCSE/ Level 3	MT/ DG - WWTP	120	4/23/2004	No	No
514	PG&E/ Level 3-R	MT/ DG - WWTP	90	5/19/2004	Yes	No
298	PG&E Level 3-R	MT/ DG - WWTP	30	8/4/2004	Yes	No
0023-01	CCSE/ Level 3	MT/ DG - WWTP	360	9/3/2004	No	No
379	PG&E/ Level 3-R	MT/ Landfill gas	280	1/14/2005	Yes	No
PY03-092	SCE/ Level 1	FC/ DG - WWTP	500	3/11/2005	Yes	Yes
640	PG&E/ Level 3-R	MT/ Landfill gas	70	4/14/2005	Yes	No

* 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.

Table 15: SGIP Projects Utilizing Renewable Fuel (Continued)

PA Project ID No.	PA/ Incentive Level	Technology/ Renewable Fuel Type	Capacity (kW)	Operational Date	RFUR Project?	Any Non-Renewable Fuel Supply?
641	PG&E/ Level 3-R	MT/ Landfill gas	70	4/14/2005	Yes	No
PY03-045	SCE/ Level 1	FC/ DG - WWTP	250	4/19/2005	Yes	No
PY03-008	SCE/ Level 3-R	MT/ Landfill gas	70	5/11/2005	Yes	No
PY03-017	SCE/ Level 3-R	ICE/ DG - WWTP	500	5/11/2005	Yes	Yes
842A	PG&E/ Level 3-R	MT/ DG - WWTP	60	5/27/2005	Yes	No
PY03-038	SCE Level 3-R	MT/ DG - WWTP	250	7/12/2005	Yes	No
747	PG&E Level 3-R	MT/ DG - WWTP	60	7/18/2005	Yes	No
653	PG&E Level 2	FC/ DG – food processing	1000	8/9/2005	No	Yes
833	PG&E/ Level 3-N	MT/ DG – food processing	70	9/1/2005	No	Yes
483	PG&E/ Level 3-R	ICE/ DG - dairy	300	1/13/2006	Yes	No
313	PG&E/ Level 3-R	MT/ DG - WWTP	300	3/16/2006	Yes	No
1222	PG&E Level 3-R	ICE/ Landfill gas	970	3/24/2006	Yes	No
1297	PG&E/ Level 3-R	MT/ DG - WWTP	280	4/7/2006	Yes	No
856	PG&E/ Level 3-R	MT/ Landfill gas	210	5/5/2006	Yes	No
658	PG&E/ Level 3-R	ICE/ DG - dairy	160	5/22/2006	Yes	No
1313	PG&E Level 3-R	MT/ DG – WWTP	240	7/17/2006	Yes	Yes
PY05-093	SCE Level 3-R	ICE/ Landfill gas	1030	9/1/2006	Yes	No
1316	PG&E Level 3-R	ICE/ Landfill gas	970	10/2/2006	Yes	No
PY04-158	SCE Level 3-R	ICE/ DG - WWTP	704*	10/25/2006†	Yes	Yes
PY04-159	SCE Level 3-R	ICE/ DG - WWTP	704	10/26/2006	Yes	Yes
1559	PG&E Level 2	ICE/ DG - WWTP	160	11/16/2006	Yes	No

* In Renewable Fuel Use Reports #9 and #10 this project's size was reported as 296 kW, the capacity used in incentive calculations. The actual physical size of the system is 704 kW.

† In Renewable Fuel Use Reports #9 through #13 this project's Operational Date was incorrectly reported as 11/15/2005. That date is an estimate of when the system began operating. For this report the basis of Operational Date values is incentive payment date.

Table 15: SGIP Projects Utilizing Renewable Fuel (Continued)

PA Project ID No.	PA/ Incentive Level	Technology/ Renewable Fuel Type	Capacity (kW)	Operational Date	RFUR Project?	Any Non-Renewable Fuel Supply?
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
1298	PG&E/ Level 3N	MT/ DG – WWTP	250	1/19/2007	No	Yes
1528	PG&E/ Level 2	MT/ DG – food processing	70	3/16/2007	Yes	No
PY06-094	SCE/ Level 2	ICE/ DG - WWTP	500	5/27/2007	Yes	No
1577	PG&E/ Level 2	ICE/ DG - dairy	80	10/1/2007	Yes	No
2005-082	SCG/ Level 3R	ICE/ DG – food processing	1080	1/15/2008	Yes	No
2006-014	SCG/ Level 2	ICE/ Landfill gas	1030	2/21/2008	Yes	No
PY06-062	SCE/ Level 2	FC/ DG – WWTP	900	3/4/2008	Yes	Yes
0270-05	CCSE/ Level 3R	MT/ Landfill gas	210	4/4/2008	Yes	No
1490	PG&E/ Level 2	FC/ DG - WWTP	600	4/24/2008	Yes	Yes
1640	PG&E/ Level 3-R	ICE/ DG - WWTP	643	7/29/2008	Yes	No
1498	PG&E/ Level 3R	MT/ Landfill gas	210	8/5/2008	Yes	No
2006-036	SCG/ Level 2	FC/ DG - WWTP	1200	10/27/2008	Yes	Yes
2006-012	SCG/ Level 2	FC/ DG – WWTP	900	12/18/2009	Yes	Yes
2008-003	SCG/ Level 2	FC/ DG – food processing	600	12/14/2009	Yes	Yes
1749	PG&E/ Level 3R	ICE/ DG - WWTP	130	11/9/2009	Yes	Yes
1775	PG&E/ Level 2	ICE/ DG - dairy	75	2/3/2010	Yes	No
0351-07	CCSE/ Level 2	ICE/ DG - WWTP	560	4/16/2010	Yes	Yes
PY10-002	SCE/ Level 2	FC/ DG - WWTP	500	10/31/2010	Yes	Yes
1810	PG&E/ Level 2	FC/ Directed landfill gas	400	11/10/2010	Yes	Yes
1811	PG&E/ Level 2	FC/ Directed landfill gas	400	11/10/2010	Yes	Yes
1812	PG&E/ Level 2	FC/ Directed landfill gas	400	11/10/2010	Yes	Yes
1802	PG&E/ Level 2	FC/ Directed landfill gas	400	12/22/2010	Yes	Yes
1759	PG&E/ Level 2	ICE/ DG - WWTP	1696	12/24/2010	Yes	No