Self-Generation Incentive Program
Semi-Annual Renewable Fuel Use Report No. 15
for the Six-Month Period Ending December 31, 2009

1. Overview

Report Purpose

This report complies with Decision 02-09-051 (September 19, 2002) that requires Self-Generation Incentive Program[1] (SGIP) 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 California Public Utilities Commission (CPUC) with information to assist 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. However, due to a growing interest in the potential for renewable fuel use projects to reduce greenhouse gas (GHG) emissions[4], this latest report augments that information with a section on GHG emission impacts from renewable fuel SGIP projects.

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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.

[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.

This RFU Report No. 15 covers the six-month reporting period of June 30, 2009 to December 31, 2009 and includes analysis of all renewable fuel use projects installed under the SGIP since the program's inception in 2001.

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

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 nonrenewable projects	Higher than nonrenewable projects
# of Projects	8	42

Summary of RFUR 15 Findings

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

- As of December 31, 2009, there were 50 RFU facilities deployed under the SGIP, representing approximately 22.3 megawatts (MW) of rebated capacity. Forty-two of these facilities were RFUR projects and represented approximately 18.5 MW of rebated capacity. The remaining eight "Other" RFU projects represented approximately 3.8 MW of rebated capacity.

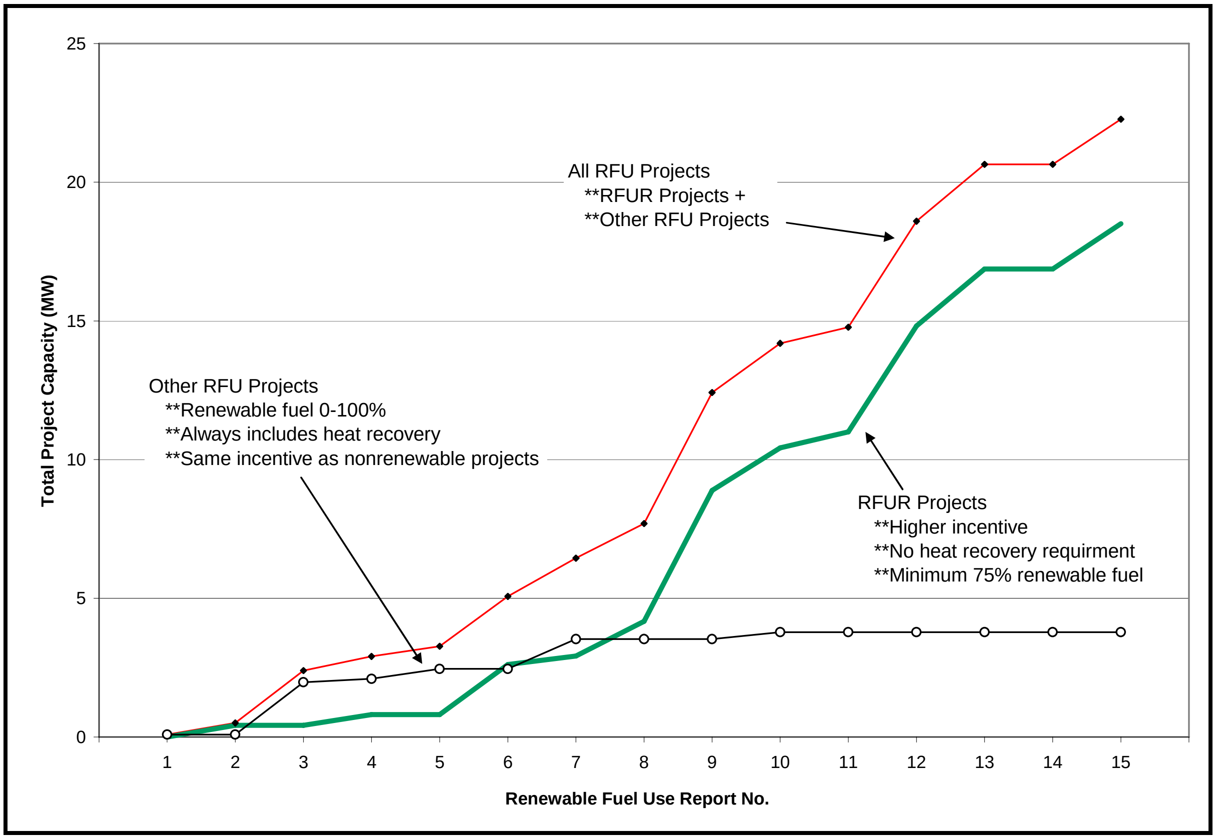
[5] The SGIP requires such projects to limit use of non-renewable fuel to 25 percent on an annual fuel energy input basis. This requirement is based on FERC definitions of renewable energy qualifying facilities from the original Public Utility Regulatory Policy Act (PURPA) of 1978.

- Thirty-one of the 42 RFUR projects (74 percent) operated solely from renewable fuels and as such inherently comply with renewable fuel use requirements. Of the remaining 11 dual-fuel RFU facilities, five were found to be in compliance with renewable fuel use requirements; three were found not to be applicable with respect to the requirements as they were no longer required to report compliance status; one was found to be out of compliance and there was insufficient data on the remaining two RFUR facilities to determine compliance status.
- RFU facilities are powered by a variety of renewable fuel (i.e., biogas) resources. However, approximately 83 percent of the rebated capacity of RFU facilities deployed through December 31, 2009 was powered by biogas derived from landfills or wastewater treatment facilities.
- Prime movers used at RFU facilities include fuel cells, microturbines, and IC engines. IC engines have been the dominant prime mover technology of choice up through the reporting period, constituting approximately 12 MW (or over 50 percent) of the overall 22.3 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 (CO_2) equivalent 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 equivalent per MWh of generated electricity; an order of magnitude greater in GHG emission reduction potential. It is important to note that the baseline biogas condition for RFU facilities was developed on assumptions. Forty of the fifty RFU facilities in the SGIP were contacted to determine the baseline biogas condition. The collected information will be used in later RFU reports to assess the potential for GHG emission reductions.
- 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 other used to generate process heat.

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 1.

Figure 1: Project Capacity Trend (RFU Reports 1–15)



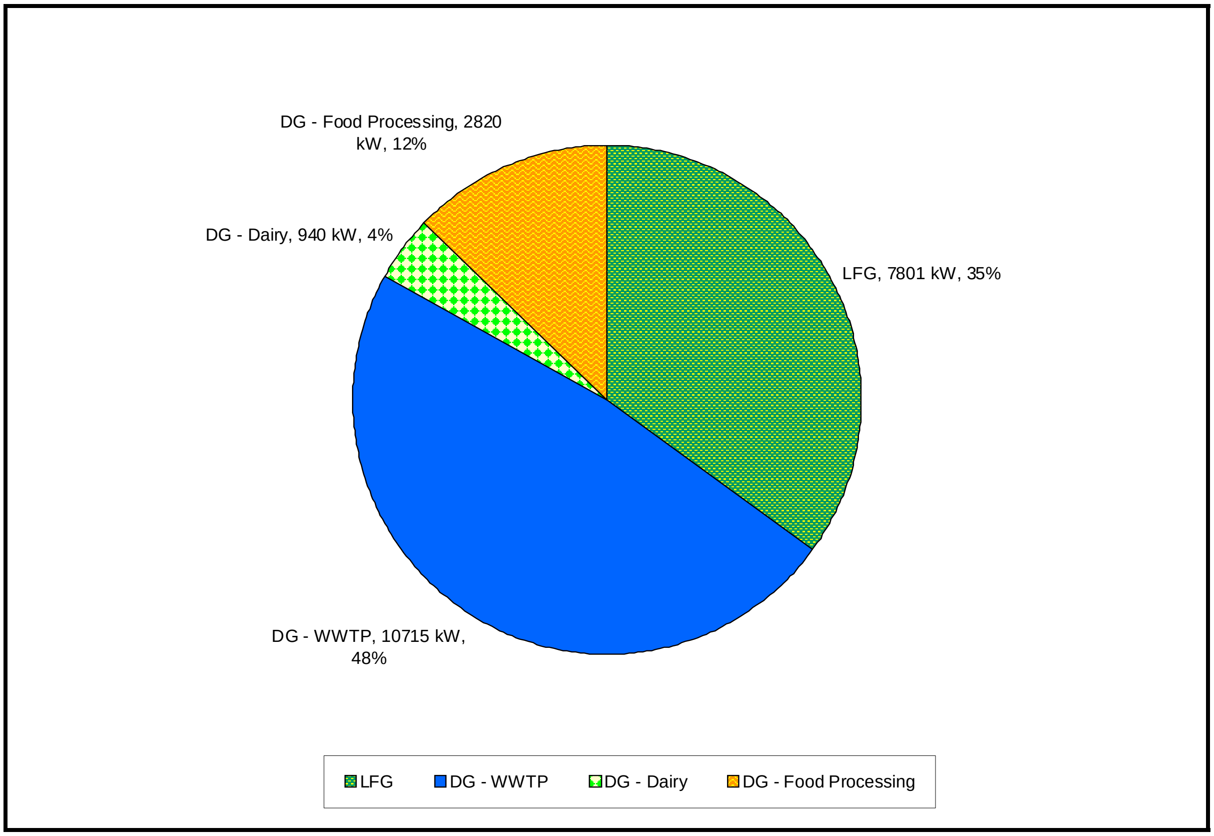
While all RFUR projects are allowed to use as much as 25 percent non-renewable fuel, most operate completely from renewable fuel resources. To date, 74 percent of the RFUR projects have operated solely on renewable fuel. Data were not available for all dual-fuel projects. However, up to and including 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 the second instance of non-compliance with these requirements.[6]

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.

6 The first instance of non-compliance was in RFU Report #13; this is the second instance and is a different project.

Figure 2 shows a breakout of RFU projects as of December 31, 2009 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 nearly half of the biogas used in SGIP RFU projects is derived from wastewater treatment plants and over a third is derived from landfill gas projects. Dairy digesters provide the smallest contribution at approximately four percent of the total rebated RFU project capacity.

Figure 2: Renewable Fuel Use Project Rebated Capacity by Fuel Type

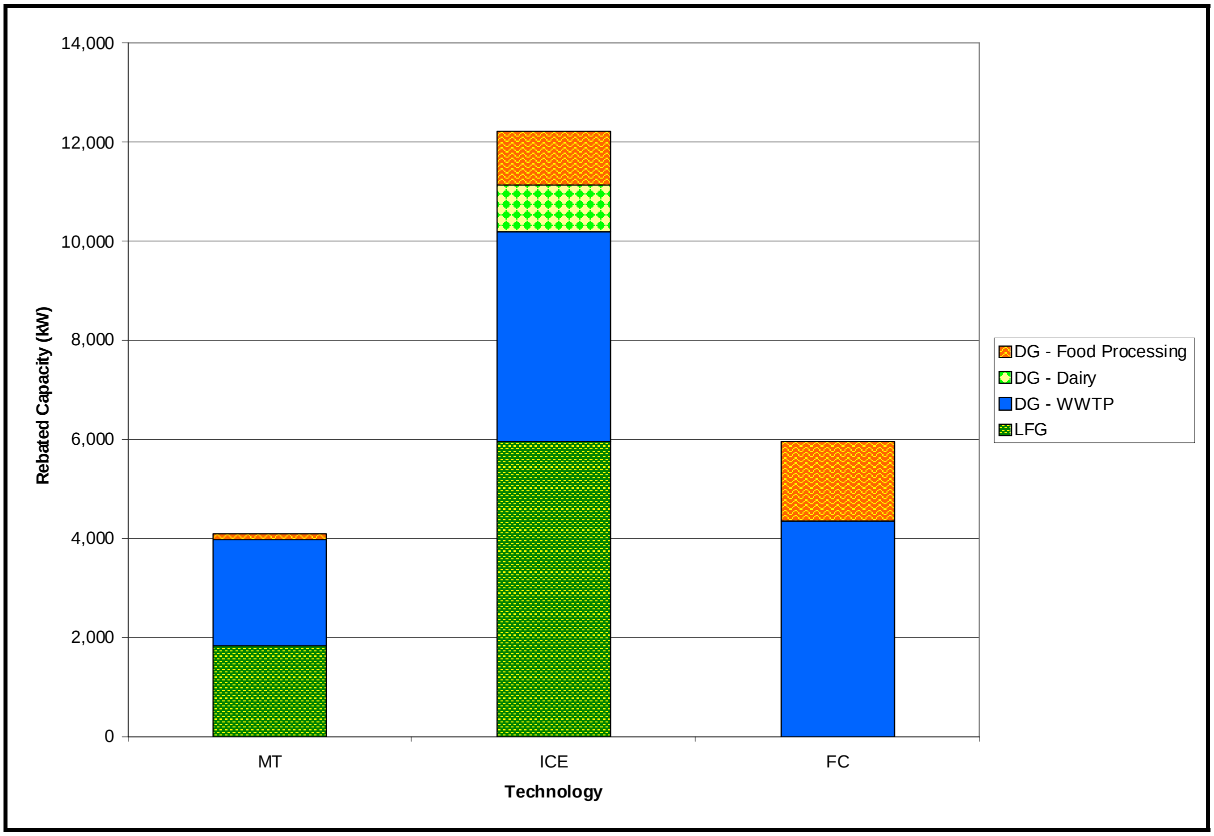


LFG = landfill gas; WWTP = wastewater treatment plants DG=digester gas

[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 3 provides a breakdown of the relative contribution of the different biogas fuels by prime mover technology. Several observations can be made from examining Figure 3. Biogas-powered internal combustion (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 3 shows that dairy digesters use IC engines exclusively for RFU power generation. Similarly, Figure 3 shows that biogas-powered fuel cells installed under the SGIP to date have been associated only with wastewater treatment facilities or food processing facilities.

Figure 3: Contribution of Biogas Fuel Type by Prime Mover Technology



LFG = landfill gas; WWTP = wastewater treatment plants; MT = microturbines; ICE = IC engines; 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 program 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 three new RFUR SGIP projects completed during the subject six-month reporting period. A total of 42 RFUR projects had been completed as of December 31, 2009. A list of all SGIP projects utilizing renewable fuel (RFUR and Other RFU) is included as Appendix A.

The 42 completed RFUR projects represent approximately 18.5 MW of installed generating capacity. The prime mover technologies used by these projects are summarized in Table 2. Close to 60 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 707 kW and that of renewable-fueled IC engines is 608 kW.

Table 2: Summary of Prime Movers for RFUR Projects

Prime Mover	No. Projects	Total Rebated Capacity (kW)	Average Rebated Capacity (kW)*
FC	7	4,950	707
MT	18	3,220	179
IC Engine	17	10,331	608
Total	**42**	**18,501**	**441**

FC = fuel cell; MT = microturbine; 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 indicate that 27 of the 42 RFUR projects recover waste heat. All but five of the 28 digester gas systems include waste heat recovery. 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-third 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.[8]

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	28	23	5
Landfill Gas	14	4	10
Total	**42**	**27**	**15**

3. Fuel Use at RFUR Projects

While all RFUR projects could use as much as 25 percent non-renewable fuel, 31 of the 42 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.

[8] In general, wastewater treatment plants have a built in thermal load as above ground digesters operate better if heated. Landfill gas operations do not typically use recovered waste heat to increase the rate of the anaerobic digestion process.

Fuel supply and contract status for RFUR projects are summarized in Table 4.

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

Fuel Supply	Warranty/Renewable Fuel Use Requirement Status[9]					
	Active		Expired		Total	
	No. Projects (n)	Rebated Capacity (kW)	No. Projects (n)	Rebated Capacity (kW)	No. Projects (n)	Rebated Capacity (kW)
Renewable only	12	5,293	19	6,230	31	11,523
Renewable & non-renewable	8	5,070	3	1,908	11	6,978
Total	**20**	**10,363**	**22**	**8,138**	**42**	**18,501**

As noted in Table 4, only 20 of the total 42 RFUR projects had active warranty status. Twenty-two RFUR projects (or over 50 percent of all RFUR projects) had an expired warranty status. This is the first RFU report in which greater than 50 percent of the SGIP RFUR warranties have expired. Of the 20 RFUR sites with active warranties, twelve operated solely on renewable fuel. By definition, all 12 of those RFUR projects are in compliance with the SGIP's renewable fuel use requirements.

In addition, Table 4 shows that 31 of the total 42 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 11 dual-fueled projects (both active and expired) is as follows.

RFUR Projects in Compliance

All Metered Data Provided

- **PG&E A-1313**. Metered daily electric generation, biogas consumption, and natural gas consumption data were obtained from the SGIP participant for this microturbine system. These data indicate that the system was off for the entire reporting period, thus both renewable and non-renewable fuel usage for this period were zero.
- **PG&E A-1749.** This 130 kW IC engine system uses renewable fuel from a wastewater treatment plant digester and recovers waste heat from the engine to preheat the digester sludge. The host has provided the total electrical output, total natural gas usage, and total biogas usage from the installation date (March 2009) until January 2010. The annual contribution of non-renewable fuel was 6 percent. Consequently, the site is in compliance with the SGIP's renewable fuel use provisions.

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9 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.

<u>Electrical Conversion Efficiency Assumed</u>[10]

- **PG&E A-1490**. This 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. Based on these estimates, Itron believes natural gas usage during the current reporting period was at most 21 percent of the total annual fuel input and the system was in compliance with the SGIP's renewable fuel use provisions.
- **SCE PY06-062.** This 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. Based on these estimates, Itron believes natural gas usage during the current reporting period was at most 7 percent of the total annual fuel input. The system was in compliance with the SGIP's renewable fuel use provisions for this reporting period.
- **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.

  Itron received natural gas usage data from SCG and metered electric output data from the applicant for the 12-month period ending December 31, 2009. Itron assumed electrical conversion efficiency to estimate total fuel use during periods of electricity generation. During this reporting period there were many hours when, instead of being generated, electricity was being consumed to maintain a "hot standby" condition. As noted above, biogas use is not metered. For the purposes of assessing compliance with the SGIP's renewable fuel use requirements Itron assumed that no biogas was used while the system was in a "hot standby" condition. The resulting estimate of non-renewable fuel contribution was at most 3 percent. In conclusion, during this reporting period the renewable fuel use was at least 97 percent and the system was in compliance with the SGIP's renewable fuel use provisions.

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[10] In these calculations an electrical conversion efficiency of 47 percent was assumed similarly to RFU Report #12. The intent was to develop an efficiency likely to be higher than the actual efficiency. If the actual efficiency is lower than 47 percent (which is likely), then the actual non-renewable fuel use is lower than the estimated percent.

RFUR Projects Not In Compliance

- **SCG 2006-036.** This 1200 kW fuel cell system 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. 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 annual natural gas usage for 2009 was at most 38 percent. The system was not in compliance with the SGIP's renewable fuel use provision for this reporting period.

RFUR Project Compliance Status Not Applicable

- **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 has 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]

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[11] These calculations assume an electrical conversion efficiency of 47 percent. The intent was to develop an efficiency value likely to be higher than the actual efficiency. If the actual efficiency is lower than 47 percent (which is likely), then the actual non-renewable fuel use is lower than the estimated percent.

[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.

RFUR Project Compliance Status Unknown

- **SCG 2006-012.** This 900 kW fuel cell project consists of three 300 kW fuel cells, 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 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. At this time only the inspection report summary has been received which indicated that each of the fuel cells were complying with the renewable fuel use requirement. The complete installation verification inspection report has been requested from SCG. No metered data were available at this time to assess the actual fuel mix during this reporting period.
- **SCG 2008-003.** This 600 kW fuel cell project consists of two 300 kW fuel cells and 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. No metered data were available at this time to assess the actual fuel mix during this reporting period.

Overall (renewable-only and dual-fuel), between 17 (85 percent) and 19 (95 percent) of the 20 RFUR projects remaining under warranty comply with the SGIP's 25 percent non-renewable requirement. In addition, there are insufficient data to draw definitive conclusions about two of these RFUR projects. A summary of renewable fuel use compliance for the 11 dual-fuel systems is presented in Table 5.

Table 5: Fuel Use Compliance of RFUR Projects Utilizing Non-Renewable Fuel

PA Project ID No.	PA/ Incentive Level	Technology/ Renewable Fuel Type	Capacity (kW)	Operational Date[13]	Annual Natural Gas Energy Flow (MM Btu)[14]	Renewable Fuel Use (% of Total Energy Input)	SGIP Warranty Status	Meets Program Renewable Fuel Use Requirements?[15]
2006-036	SCG/Level 2	FC/ DG WWTP	1200	10/27/2008	14,131	≥62	Active	No
PY03-092	SCE / Level 1	FC / DG - WWTP	500	3/11/2005	114	≥97	Active	Yes
1313	PG&E / Level 3-R	MT / DG - WWTP	240	3/6/2007	0	Not Applicable [16]	Active	Yes
PY06-062	SCE/Level 2	FC/DG - WWTP	900	3/4/2008	2,141	≥93	Active	Yes
1490	PG&E/Level 2	FC/DG - WWTP	600	4/24/2008	5,653	≥79	Active	Yes
1749	PG&E / Level 3-R	IC Engine / DG - WWTP	130	11/9/2009	437	94	Active	Yes
2006-012	SCG/ Level 2	FC/DG - WWTP	900	12/18/2009	Not Available[17]	Not Available	Active	Unknown
2008-003	SCG/Level 2	FC/DG – food processing	600	12/14/2009	Not Available	Not Available	Active	Unknown
PY03-017	SCE / Level 3-R	IC Engine / DG - WWTP	500	5/11/2005	Not Available	Not Available	Expired	Not Applicable
PY04-158	SCE / Level 3-R	IC Engine / DG - WWTP	704 [18]	10/25/2006[19]	Not Available	Not Available	Expired	Not Applicable
PY04-159	SCE / Level 3-R	IC Engine / DG - WWTP	704	10/26/2006[19]	Not Available	Not Available	Expired	Not Applicable

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

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13 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.

14 This field represents the natural gas consumption during the 12-month period ending December 31, 2009. The basis is the LHV of the fuel.

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

16 The percent of renewable fuel used is not applicable during this reporting period because the denominator (i.e., Total Energy Input) is zero.

17 Not Available. Metered data necessary to calculate estimates of natural gas energy use were not available for this reporting period. Projects with active warranties are not required to meter system performance, but those that do are required to share their data for program evaluation purposes. Once a project's warranty has expired, the site is no longer required to share data.

18 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.

19 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.

4. Greenhouse Gas Emissions Impacts

Previous RFU reports have not included information about GHG emissions from renewable fuel use projects. However, due to increased interest in the GHG emission aspects of biogas projects[4], additional detail regarding GHG emission impacts is presented in this section. This GHG emission information was previously presented in the SGIP Eighth-Year Impact Evaluation Final Report[20]. Additionally, key factors that could influence GHG emission impacts from renewable fuel projects in the future are discussed.

Table 6 presents the capacity-weighted average GHG emission results developed from the SGIP Eighth-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 6 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.[21] 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 2008.

Table 6: Summary of CO_2 Emission Impacts from SGIP Biogas Projects in 2008

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	-0.55	-0.53 to -0.58
	MT	-0.53	-0.53 to -0.64
	IC Engine	-0.55	-0.46 to -0.54
Vent	MT	-5.83	-4.68 to -4.73
	IC Engine	-4.71	-5.73 to -5.96

20 GHG Information from the SGIP Eighth-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 PG&E’s website (http://www.pge.com/mybusiness/energysavingsrebates/selfgenerationincentive/measurementevaluationreports.shtml)

21 Baseline conditions for RFU projects were assumed at the time of the Eighth-Year SGIP Impact Evaluation as there had been insufficient time to contact the various RFU projects. In addition, assumptions on baseline conditions had been based on previous studies conducted on renewable fueled facilities in California.

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)[22]
- Estimates for GHG reductions from biogas projects were based solely on estimates of the methane in the used biogas and were not take into account natural gas used by the biogas facilities
- A single representative electrical conversion efficiency was assumed for each technology

All SGIP impacts evaluations to date have 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.[23] At the state level, the California Air Resources Board (CARB) provides guidelines for control of methane and other volatile organic compounds from biogas facilities.[24] At the federal level, New Source Performance Standards and Emission Guidelines regulate methane capture and use.[25] The baseline conditions were based on previous studies.[26] [27] For example all dairies were previously assumed to have vented the methane. All landfill gas facilities were previously assumed to have captured and flared the methane. For wastewater treatment plants and food processing facilities, the threshold of 150 kW was chosen as the cut-off point between venting and flaring methane. Smaller wastewater treatment plants were assumed to vent the methane, and larger ones were assumed to flared methane. Flaring was assumed to have essentially the same degree of combustion completion as SGIP renewable fuel use facilities, thus there was no net CH_4 benefit.

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22 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 year in which renewable fueled systems were required to recover heat and meet system efficiency requirements of Public Utilities Code 218.5 (now 216.6).

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

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

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

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

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

Because the biogas baseline is such an influential determinant of GHG emissions impacts for this report, program participants were contacted to gather additional site-specific information about actual biogas baselines. Representatives of 40 of the 50 RFU projects were successfully contacted to collect site-specific information about baseline biogas use. Table 7 below shows a summary of these results. Thirty-eight of the 40 SGIP participants contacted indicated that if they had not installed the SGIP prime mover they would be flaring biogas. All of the wastewater treatment plants (WWTP) and food processing facilities reported a biogas baseline of flaring. One of the three dairies reported a flaring baseline. This information will be used to increase accuracy of estimated GHG emission impacts calculated for future SGIP impact evaluations.

Table 7: Summary of Site-Specific Biogas Baseline Research

Facility Type	Size of Rebated System	Reported Biogas Baseline	
		Flaring (No. Projects)	Venting (No. Projects)
WWTP	<150	7	0
	≥150	14	0
Food Processing	<150	2	0
	≥150	2	0
LFG	All Sizes	12	0
Dairy	All Sizes	1	2
Total*		**38**	**2**

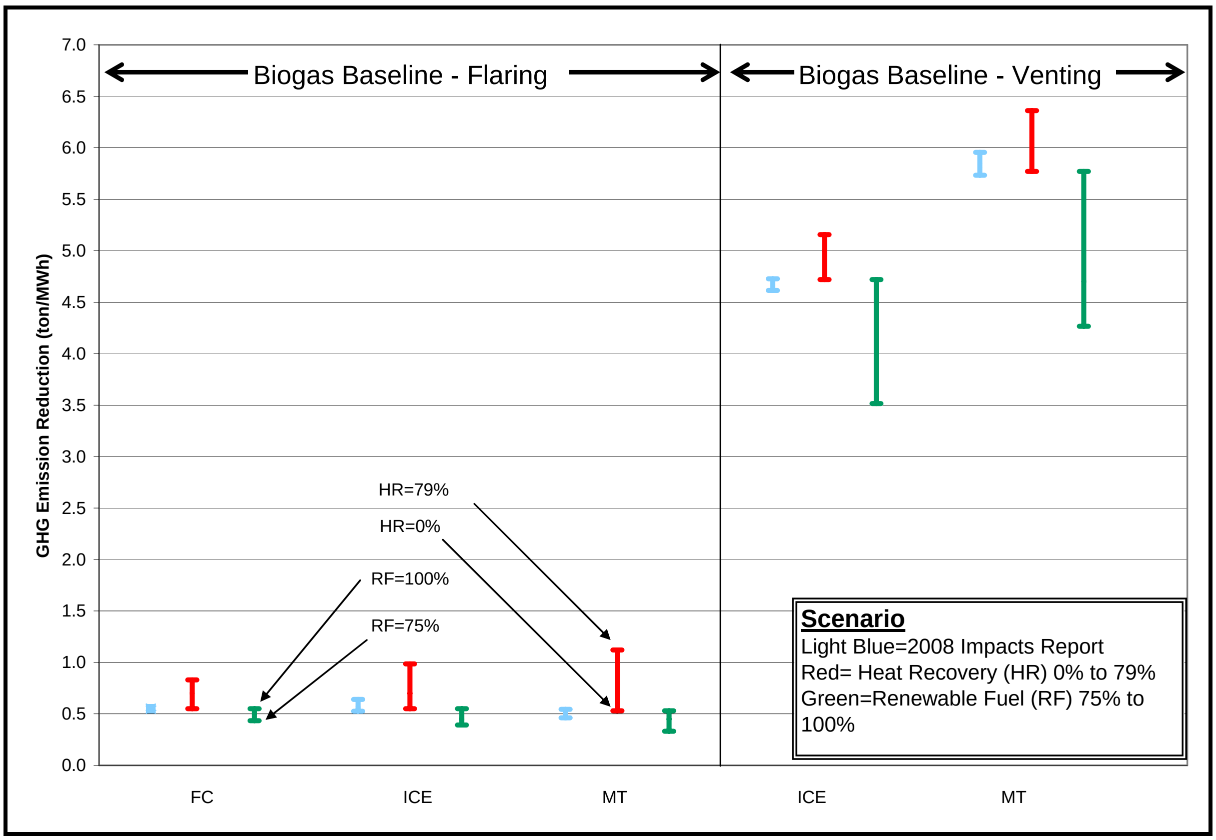
* The total number of sites contacted was 44. However only 40 sites had responded at the time of this report.

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[28] 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 their use of non-renewable fuel to 25 percent (i.e., renewable fuel minimum 75 percent).

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

Figure 4 shows the GHG emission reductions associated with these hypothetical scenarios compared to the 2008 impact report GHG emission reduction range. As shown, both scenarios could introduce much greater variability in GHG emission reductions than the 2008 impact report 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 4 : GHG 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:[29]

- 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 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.

[29] 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, 2009 are summarized in Table 8. 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 8 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 8: 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	6	4.51 - 9.85	6.64	7.04	2.20	6.33
	Yes	No	2	9.48 - 9.69	9.59	9.59	0.15	9.61
	Yes	Yes or No	8	4.51 - 9.85	8.28	7.68	2.20	7.16
	No	Yes	17	5.06 - 18.00	7.10	8.50	3.47	7.62
IC Engine	Yes	Yes	16	1.08 - 5.70	2.68	2.64	1.23	2.53
	Yes	No	3	1.71 - 2.87	2.66	2.41	0.62	2.69
	Yes	Yes or No	19	1.08 - 5.70	2.66	2.61	1.15	2.56
	No	Yes	218	0.85 - 10.70	2.29	2.53	1.21	2.27
MT	Yes	Yes	13	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	23	1.23 - 11.30	3.75	4.40	2.30	3.78
	No	Yes	114	0.70 - 6.39	3.17	3.26	1.17	3.16

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

* 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.

$$\Delta Heat\,\mathrm{Re}\,\mathrm{cov}\,ery = \begin{pmatrix} RFU \\ w/\,HR \end{pmatrix} - \begin{pmatrix} RFU \\ w/\,o\,HR \end{pmatrix}$$

Equation 1

Where

RFU = renewable fuel use

HR = heat rate

w/ = with

w/o = without

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 ($0.11) is calculated as $2.64 minus $2.53.

$$\Delta Fuel\,Treatment = \begin{pmatrix} RFU \\ w/\,HR \end{pmatrix} - \begin{pmatrix} NG \\ w/\,HR \end{pmatrix}$$

Equation 2

Where

NG = natural gas

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 ($0.08) is calculated as $2.61 minus $2.53.

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

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 8.

Microturbine Project Cost Comparisons

Cost comparison results for microturbines are summarized in Table 9. 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.[30]

Table 9: 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	1.87	1.20 to 2.54
RFU	1.14	0.60 to 1.68

The 90 percent confidence intervals presented in Table 9 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.

[30] 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 & $n_2 \geq 30$ then a z-Test is used to determine confidence intervals. When n_1 or $n_2 < 30$ then a t-Test is used.

IC Engine Project Cost Comparisons

Cost comparison results for IC engines are summarized in Table 10. Results for the incremental difference due to heat recovery are not presented because all but three of the renewable IC engine projects completed to date have included heat recovery even though it was not required by the SGIP. 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 10: IC Engine Project Cost Comparison Summary

Physical Difference	Difference of Means ($/Watt)	90% Confidence Interval ($/Watt)
Fuel Treatment	0.11	-0.14 to 0.63
RFU	0.08	0.40 to 0.56

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 11. 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 11: Fuel Cell Project Cost Comparison Summary

Physical Difference	Difference of Means ($/watt)	90% Confidence Interval ($/watt)
Fuel Treatment	-1.46	-4.09 to 1.17
RFU	-0.82	-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, 2009 reveals that average non-renewable generator costs have 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 program 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.

6. Observations and Recommendations

Based on data collected on the RFU facilities and on metering operations, Itron provides the following observations and recommendations:

1. Metering of fuel consumption and electricity generation by RFUR facilities is critical to verifying compliance of these facilities with renewable fuel requirements. In addition, metering provides valuable information on biogas use at blended facilities (whether RFUR or RFU) and help measure actual GHG emission reductions. .It is not feasible to add new metering of natural gas at existing SGIP facilities with blended (biogas and natural gas) use due to safety and cost.
   a. The Working Group (WG)/CPUC should require for new RFU facilities either
      1) installation of natural gas metering or
      2) installation of a T-valve with an up-stream shut-off so that metering can be installed.
   b. Note: in the event the CPUC/WG determines that GHG emission reductions have a time dependent value, natural gas metering should provide hourly readings.

2. The baseline conditions of RFU projects have significant impact on the amount of available GHG emission reductions (i.e., vented projects have significantly more GHG emission reduction potential than flared projects).
    a. In addressing reconfiguration of the SGIP to meet SB 412 goals, the CPUC/WG may want to consider targeting the RFU aspect of the program to projects that have a venting baseline and using higher incentives to capture a higher number of these projects (which will provide greater GHG emission reduction benefits).
    b. Technical and economic potential studies on biogas energy from landfill gas, wastewater treatment facilities, dairies, and food processing facilities should be updated to help identify the locations and magnitude of potential RFU projects with a venting baseline. The CPUC/WG should consider funding these potential studies to help identify possible targeting of these RFU projects.
3. Aside from a venting baseline, the amount of GHG emission reduction potentially available from RFU facilities is also influenced by factors such as waste heat recovery. In a number of instances, waste heat recovery not only provides greater GHG emission reductions but can also increase the cost-effectiveness of the RFU project.
    a. For RFU projects where there is an on-site use of recovered waste heat, the CPUC/WG may want to consider requiring waste heat recovery or providing higher incentives for projects that recover waste heat.
4. 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).
    a. 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.
    b. 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.*

Appendix A

List of All SGIP Projects Utilizing Renewable Fuel

All SGIP projects supplied with renewable fuel are listed in Table 12. 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 small portion of these projects (26 percent) is also equipped with a non-renewable fuel supply. These projects are identified in the "Any Non-Renewable Fuel Supply?" column.

Table 12: SGIP Projects Utilizing Renewable Fuel

PA Project ID No.	PA/ Incentive Level	Technology/ Renewable Fuel Type	Capacity (kW)	Operational Date[31]	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	IC Engine/ Landfill gas	970	9/29/2003	No	No
110	PG&E/ Level 3	IC Engine/ 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

31 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 12: 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?
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
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	IC Engine/ 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	IC Engines/ 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	IC Engines/ 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	IC Engines/ DG - dairy	160	5/22/2006	Yes	No

Table 12: 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?
1313	PG&E Level 3-R	MT/ DG – WWTP	240	7/17/2006	Yes	Yes
PY05-093	SCE Level 3-R	IC Engines/ Landfill gas	1030	9/1/2006	Yes	No
1316	PG&E Level 3-R	IC Engines/ Landfill gas	970	10/2/2006	Yes	No
PY04-158	SCE Level 3-R	IC Engines/ DG - WWTP	704[32]	10/25/2006[33]	Yes	Yes
PY04-159	SCE Level 3-R	IC Engines/ DG - WWTP	704	10/26/2006[33]	Yes	Yes
1559	PG&E Level 2	IC Engines/ DG - WWTP	160	11/16/2006	Yes	No
1308	PG&E Level 3-R	IC Engines/ DG - dairy	400	11/17/2006	Yes	No
1505	PG&E Level 2	IC Engines/ 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	IC Engines/ DG - WWTP	500	5/27/2007	Yes	No
1577	PG&E Level 2	IC Engines/ DG - dairy	80	10/1/2007	Yes	No
2005-082	SCG/ Level 3R	IC Engines/ DG – food processing	1080	1/15/2008	Yes	No
2006-014	SCG/ Level 2	IC Engines/ Landfill gas	1030	2/21/2008	Yes	No
PY06-062	SCE/ Level 2	FC/ DG – WWTP	900	3/4/2008	Yes	Yes

[32] 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.

[33] 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, as described in footnote 13.

Table 12: 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?
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	IC Engines/ DG - WWTP	643	7/29/2008	Yes	No
1498	PG&E Level 3-R	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