Electric | Gas | Water
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CPUC Self-Generation Incentive Program Fifth Year Impact Evaluation

Final Report

Submitted to:

PG&E
and
The Self-Generation Incentive Program Working Group

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Table of Contents

List of Figures

List of Figures (continued)

List of Tables

List of Tables (continued)

1

Executive Summary

1.1 Introduction

The Self-Generation Incentive Program (SGIP) was established in response to Assembly Bill (AB) 970[1], which required the California Public Utilities Commission (CPUC) to initiate certain load control and distributed generation (DG) program activities. The CPUC issued Decision 01-03-073 (D.01-03-073) on March 27, 2001 outlining provisions of a distributed generation program. The first SGIP application was accepted in July 2001. Today, the SGIP represents the single largest DG incentive program in the country. Approximately 860 DG facilities representing slightly over 200 megawatts of rebated generation capacity have been installed and received rebate checks under the program.

In its March 2001 decision, the CPUC authorized the SGIP Program Administrators "to outsource to independent consultants or contractors all program evaluation activities…." Impact evaluations were among the evaluation activities outsourced. This report provides the findings of an impact evaluation of the fifth program year of the SGIP covering the 2005 calendar year. The evaluation covers all SGIP projects coming on-line prior to January 1, 2006. The evaluation examines impacts or requirements associated with energy delivery; peak demand; efficiency and waste heat utilization; renewable fuel use; and greenhouse gas emission reductions. Impacts are examined at the program-wide level, and at a project-specific level, depending on availability of data. Although SGIP impacts on the transmission and distribution (T&D) system was to be included in this impacts evaluation, data sets necessary for the impact evaluation could not be obtained in time. Impacts on the T&D system will be addressed in the 2006 Impact Evaluation Report.

A number of DG technologies receive rebates under the SGIP. Rebates are provided in accordance with incentive level. Incentive levels and the groupings of technologies that fall within them have changed over time. Table 1-1 summarizes the association of SGIP technologies by incentive level as of 2005 and that are used in this report.

1 Assembly Bill 970 (Ducheny, September 7, 2000)

Table 1-1: SGIP Incentive Levels and Associated Technologies

Program Incentive Category	Eligible Generation Technologies
Level 1	Renewable fuel cells
	Photovoltaics (PV)
	Wind Turbines
Level 2	Non-renewable fuel cells
Level 3	Non-renewable internal combustion engines and microturbines
Level 3-R	Renewable-fueled microturbines
	Renewable-fueled internal combustion engines and small gas turbines
Level 3-N	Non-renewable- and waste gas-fueled microturbines
	Non-renewable- and waste gas-fueled internal combustion engines and small gas turbines

1.2 Program-Wide Findings

Program Status

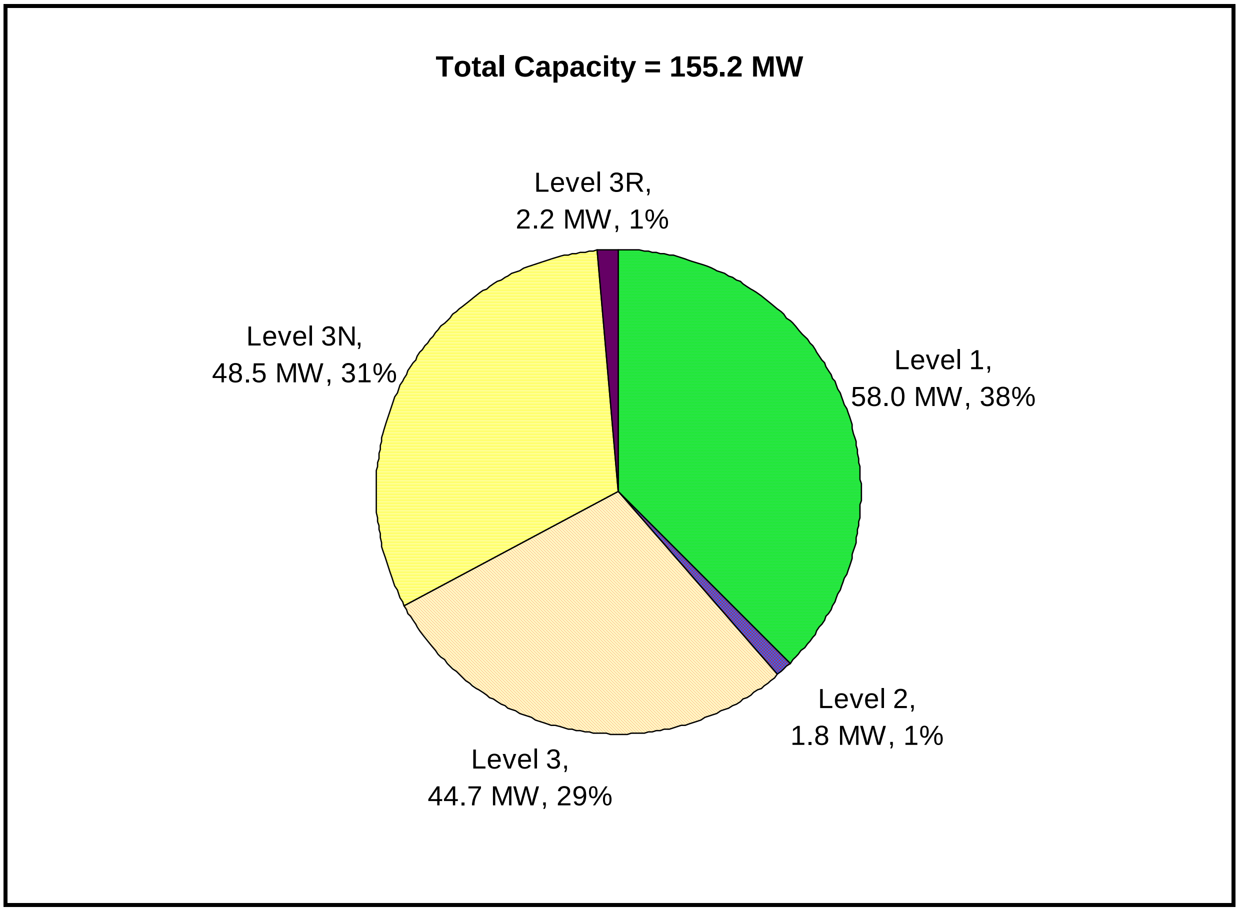
The SGIP has been growing steadily and represents a balanced portfolio of technologies, spread reasonably among Program Administrators (PAs). By the end of 2005, there were 784 projects on-line representing over 190 megawatts (MW) of rebated generating capacity. SGIP projects are distributed among SGIP PAs as shown in Table 1-2.

Table 1-2: Distribution of Projects and Rebated Capacity Among PAs as of 12/31/05

PA	No. of Projects	Capacity (MW)	% of Total Capacity
PG&E	346	81.9	42.7
SCE	205	36.6	19.1
SoCalGas	131	53.1	27.7
SDREO	102	20.0	10.4
Totals	**784**	**191.6**	**100**

The capacity of Complete[2] projects more than tripled from 2003 to 2005. Most of the growth in capacity of Complete projects was due to almost equal contributions in capacity from Level 1, 3, and 3-N projects. Figure 1-1 shows the generating capacity distribution by incentive level by the end of 2005.

Figure 1-1: SGIP Capacity (MW) by Incentive Level as of 12/31/05

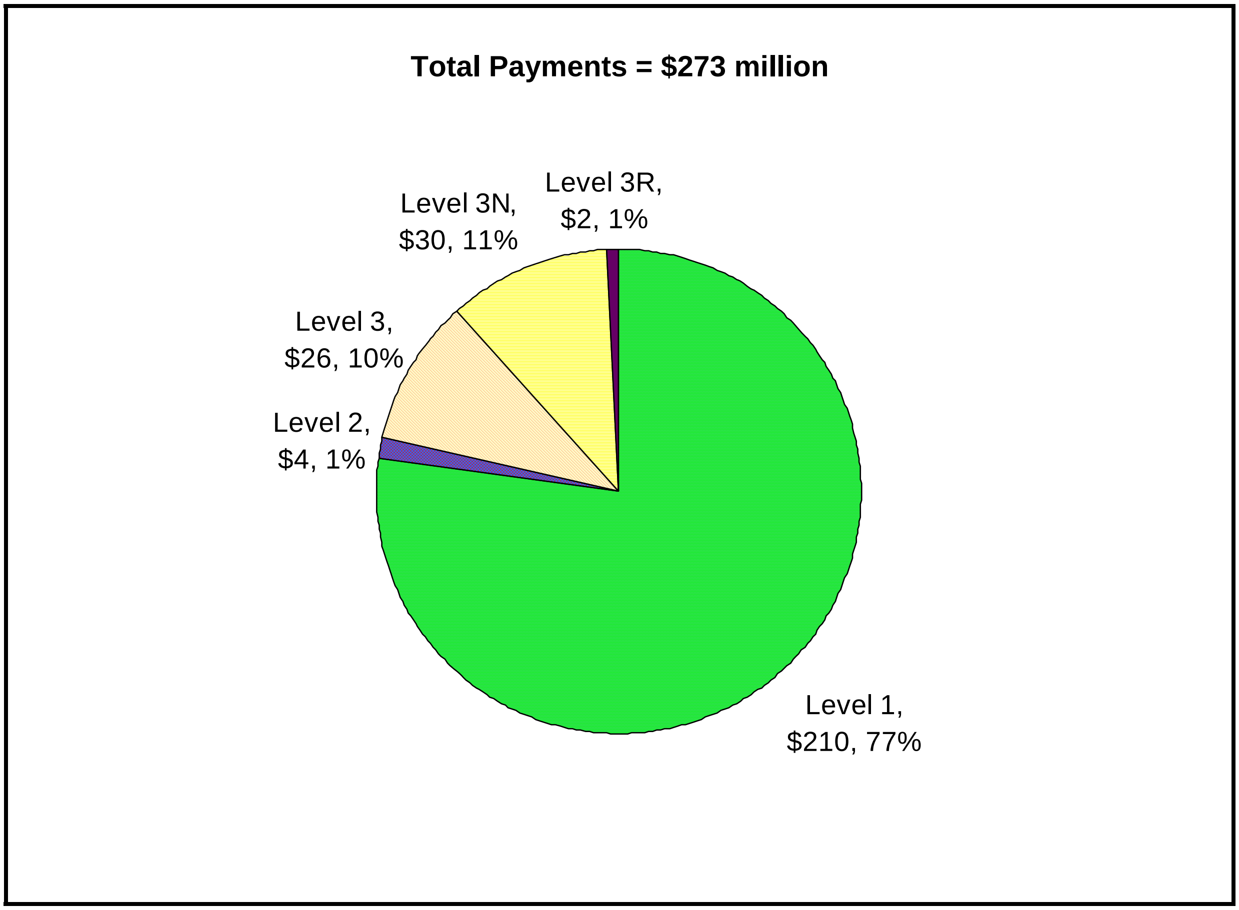


In accordance with the growth in SGIP capacity, the amount of incentives paid under the SGIP has also advanced steadily. Incentives paid under the SGIP nearly doubled between 2004 and 2005 (from $143 million to $273 million). Over 75 percent of incentives have been paid to Level 1 projects, primarily PV projects.

2 Complete projects are defined as those projects that are on-line and had received an SGIP incentive check

Figure 1-2 shows the distribution of incentives paid by incentive level as of the end of 2005. In addition, SGIP incentives have been matched by private and public funds at a level of approximately 2.5 to 1, with total eligible project costs approaching $700 million.

Figure 1-2: Incentive Payments by Level as of 12/31/05 ($Millions)



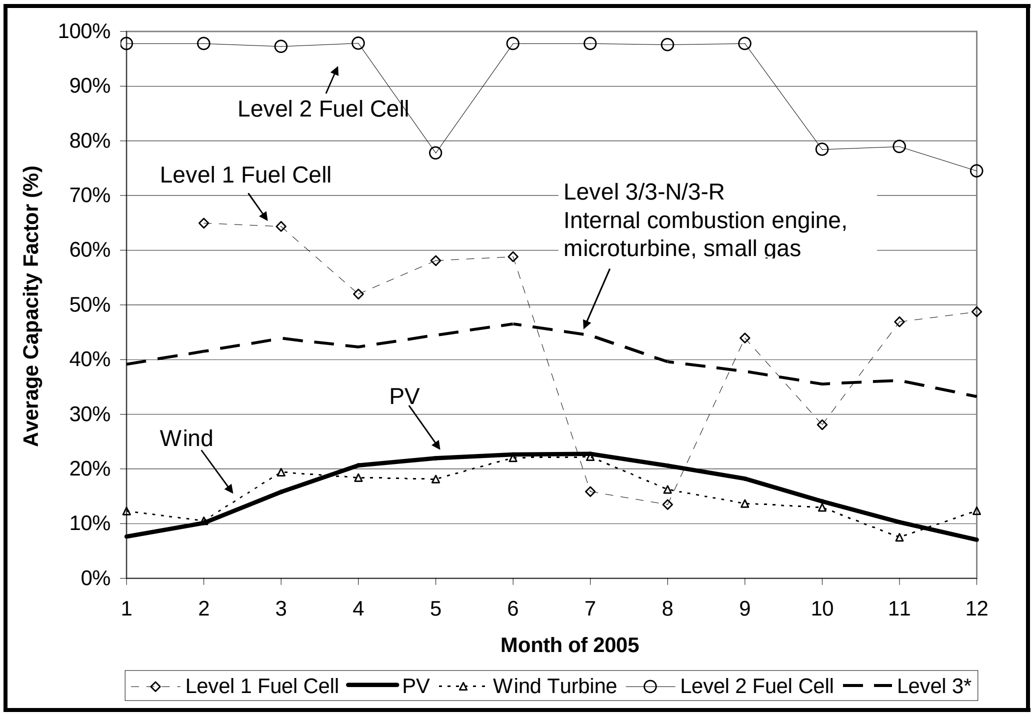
Energy and Demand Impacts

During PY05, SGIP projects delivered over 480,000 MWh of electricity. As SGIP projects are located at customer host sites of the Investor-Owned Utilities (IOUs) to help meet on-site demand, this represented electricity that did not have to be generated by central station power plants and delivered by the transmission and distribution system.

Thermal cogeneration systems (Level 3/3-N/3-R engines and turbines) provided over 80 percent of the electricity delivered during 2005. Level 1 PV projects supplied the next largest amount at approximately 14 percent of the total.

For purposes of this report, capacity factor represents the proportion of the capacity delivered by a project at any point in time relative to its rebated capacity. Figure 1-3 shows monthly capacity factors of SGIP technologies (categorized by incentive level) throughout 2005. Overall, natural gas powered fuel cells demonstrated the highest capacity factor, generally ranging above 80 percent.[3] Level 3/3-N/3-R projects, which constitute nearly two-thirds of the 2005 SGIP capacity, had average capacity factors that remained fairly steady between 35 to 45 percent. PV projects had average capacity factors ranging from slightly less than 10 to over 20 percent.

Figure 1-3: Average Capacity Factor by Month During 2005



[3] The drop in capacity factor seen for natural gas fuel cells during the mid and later part of 2005 can be attributed to troubleshooting of the few number of fuel cells operational in the SGIP at this time. Similarly, the significantly lower capacity factors of Level 1 (renewable fuel based) fuel cells can be attributed to increased operational issues associated with cleaning of renewable fuels.

Peak Demand Impacts

The ability of SGIP projects to supply on-site electricity during peak demand is critical. Delivery during peak hours reduces grid impacts by alleviating the need to bring on peaking generators as well as by decreasing transmission line congestion. In addition, by offsetting more expensive peak electricity, SGIP projects provide potential cost savings to the host site. Peak demand impacts for PY05 were estimated by looking at SGIP contributions coincident with the California Independent System Operator (CAISO) 2005 system peak load. The system reached a peak of 43,380 MW on July 20, 2005 from 3.00 to 4.00 P.M. Total SGIP project capacity coincident with the peak was estimated at slightly below 93 MW. Level 3/3-N/3-R engines and turbines accounted for 73 percent of the 2005 peak demand impact; and Level 1 PV systems accounted for 24 percent. Figure 1-4 depicts the impact of SGIP projects on the 2005 system peak.

Figure 1-4: SGIP Project Impacts on 2005 System Peak by Incentive Level

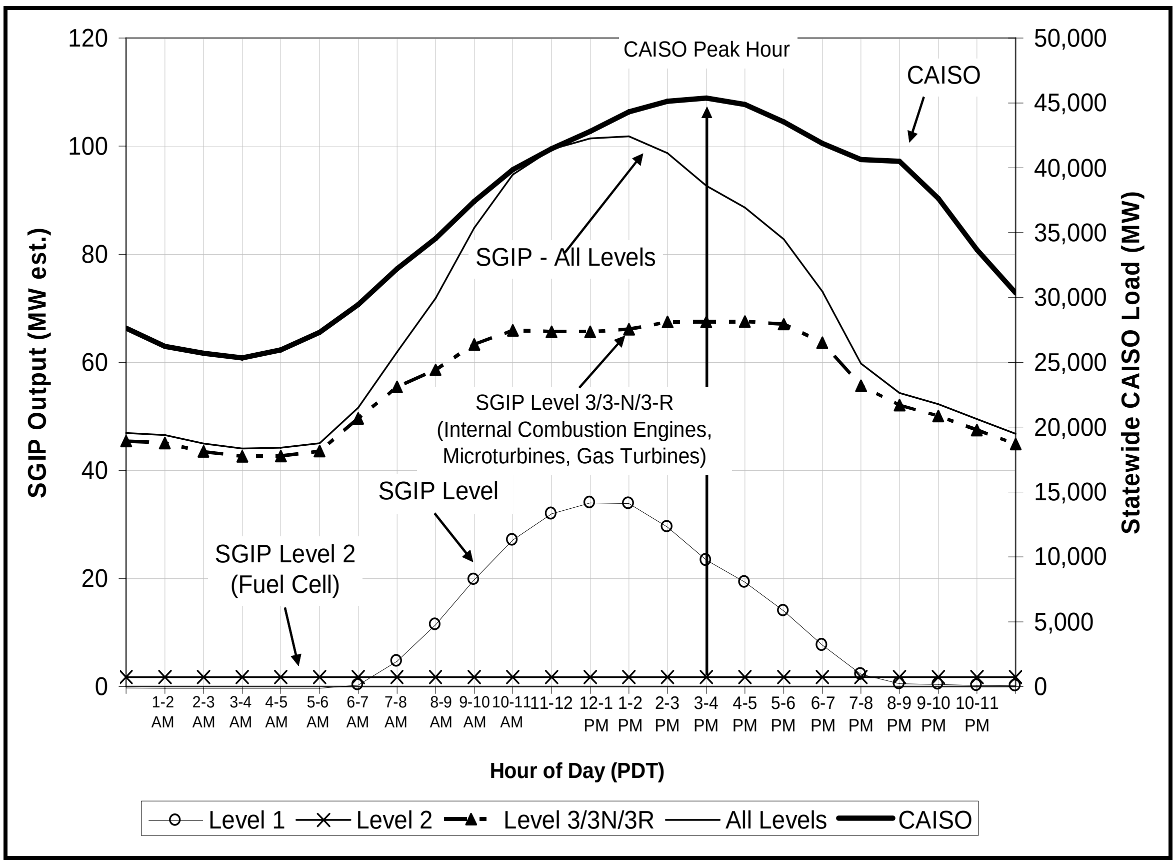


Table 1-3 provides a breakdown of SGIP impact on coincidence peak by incentive level and technology type. Unit demand refers to the capacity of generation available at the peak relative to the total capacity potentially available, and is expressed in units of kWp/kW. The relatively low 0.46 kWp/kW unit demand impact of PV systems is strongly influenced by the late afternoon timing of the CAISO system peak, which occurs 3 hours later than when PV generation is at a maximum. The 0.62 kWp/kW unit demand impact of engines, microturbines, and gas turbines is lower than expected due to a number of these cogeneration systems being idle on the day of the system peak.

Table 1-3: Breakout of SGIP Project Impact on 2005 Coincident Peak

Incentive Level	Technology	On-Line Systems (n)	On-Line Capacity (kW)[4]	Peak Demand Impact (kW_P)	Unit Demand Impact (kW_P/kW)
1	Solar Photovoltaic (PV)	**435**	**49,602**	**22,556**	0.45
	Wind Turbine	**2**	**1,649**	**906**	0.55
	Fuel Cell (renewable fuel)	**2**	**750**	**-54**	-0.07
2	Fuel Cell (natural gas)	**3**	**1,800**	**1,762**	0.98
3, 3-N, & 3-R	Engine, Microturbine, or Gas Turbine	**217**	**106,721**	**67,536**	0.63
	Total	**659**	**160,522**	**92,707**	**0.58**

Efficiency and Waste Heat Utilization

Cogeneration facilities represent approximately two-thirds of the on-line generating capacity of the SGIP. To ensure that SGIP cogeneration facilities harness waste heat and realize high overall system and electricity efficiencies, participating Level 2 and Level 3/3-N technologies face certain minimum levels of thermal energy utilization and overall system efficiency as specified in Public Utility Code (PUC) 218.5. PUC 218.5(a) requires that recovered useful waste heat from a cogeneration system exceeds five percent of the combined recovered waste heat plus the electrical energy output of the system. PUC 218.5(b) requires that the sum of the electric generation and half of the heat recovery of the system exceeds 42.5 percent of the energy entering the system as fuel.

End uses served by recovered useful thermal energy in SGIP cogeneration systems include heating, cooling, or both. Available metered thermal data and input fuel collected from on-line cogeneration projects were used to calculate overall system efficiency incorporating both electricity produced as well as useful heat recovered. The end uses served by recovered useful thermal energy at projects that had come on-line through the end of 2005 are summarized in Table 1-4.

[4] On-line capacity of the SGIP is dependent on the number of projects that come into service during the course of the year. Consequently, the on-line capacity of the SGIP was approximately, 160 MW by July 20, 2005 and reached approximately 190 MW by December 31, 2005.

Table 1-4: End-Uses Served by Level 2/3/3-N Recovered Useful Thermal Energy (Total n and kW as of 12/31/2005)

End Use Application	On-Line Systems (n)	On-Line Capacity (kW)
Heating Only	157	69,546
Heating & Cooling	54	33,771
Cooling Only	25	19,253
To Be Determined	10	5,407
Total	236	122,570

Available metered thermal data collected from on-line cogeneration projects were used to calculate overall system efficiency incorporating both electricity produced as well as useful heat recovered. Results are summarized in Table 1-5.

Table 1-5: Level 3/3-N Cogeneration System Efficiencies (n=74)

Summary Statistic	218.5 (a) Proportion	218.5 (b) Efficiency	Overall Plant Efficiency
Min	1%	8%	11%
Max	72%	54%	72%
Median	45%	39%	51%
Mean	46%	41%	53%
Std Dev	12%	8%	11%
Coefficient of Variation	0.3	0.2	0.2

Metered data collected to date suggest that 26 of the 74 monitored Level 3/3-N projects achieved the 218.5 (b) overall system efficiency target of 42.5 percent. Seven of these 26 systems utilize recovered heat to meet both heating and cooling needs.

One possible explanation for the lower than expected efficiency results could be tied to low electricity efficiencies. Results of an analysis of SGIP cogeneration system electrical conversion efficiencies are presented in Table 1-6. In the case of reciprocating internal combustion engines (ICE), actual electrical conversion efficiencies of approximately 29 percent are typical for monitored SGIP cogeneration systems. However, this typical result is below electrical conversion efficiencies normally found in published technical specifications of engine-generator set manufacturers. These nominal nameplate electrical generating efficiencies published by manufacturers generally exceed 30 percent, and sometimes exceed 35 percent.

Table 1-6: Level 2/3/3-N Electrical Conversion Efficiency

Summary Statistic	Fuel Cells (FC)	Internal Combustion Engines (ICE)	Microturbines (MT)
n	2	55	16
Min	41%	19%	6%
Max	43%	37%	29%
Median	42%	29%	22%
Mean	42%	29%	21%
Std Dev	2%	3%	5%

Renewable Fuel Use Requirements

Renewable fuel use facilities have the potential to provide specific benefits to the SGIP including emission benefits and reduced use of natural gas. Consequently, there is an emphasis on ensuring that renewable fuel use facilities are in fact using renewable resources as their primary source of fuel. In accordance with CPUC Decision 02-09-051, renewable fuel use facilities cannot receive more than 25 percent of their annual input energy from non-renewable sources.

At the end of 2005, there were 20 renewable fuel use projects on-line in the SGIP with an estimated combined generating capacity of approximately 5.2 MW. Table 1-7 summarizes the numbers and capacity of renewable fuel use facilities by incentive level and technology type. Microturbine projects represent the greatest number of renewable fuel use facilities. However, due to their generally larger capacity, IC engines represented the single largest capacity of renewable fuel use technology. Review of the renewable fuel use facilities determined that all of the twenty facilities complied with the renewable fuel use requirements.

Table 1-7: Quantities and Capacities of Renewable Fuel Use Facilities as of 12/31/05

Level	Technology Type	No of Facilities	Rebated Capacity (kW)
3	Engine	1	991
	Microturbine	3	564
3R	Engine	3	960
	Microturbine	11	1,970
1	Fuel Cell	2	750
	Total	**20**	**5,235**

CPUC Decision D.02-09-051 also requires PAs to monitor cost differences between Level 3 and 3-R projects. In the early years of the SGIP, there was concern that because Level 3-R projects were exempt from waste heat recovery requirements, their project costs could fall below Level 3 costs. As a result, Level 3-R projects could potentially be receiving a greater than necessary incentive level, which could lead to fuel switching. Comparisons between the installed costs of renewable and non-renewable fueled generation systems operational as of December 31, 2005 determined that most renewable generators are more capital intensive than their non-renewable fuel counterparts. Similarly, it appears that the differences in capital cost between renewable and non-renewable fueled generators may be due mainly to increased gas clean up required on the renewable powered systems.

Greenhouse Gas Emission Reductions

Increased interest and concern over greenhouse gas (GHG) emissions prompted an examination of the impact of GHG emissions from SGIP projects in this impact evaluation. The net difference in GHG emissions due to operation of SGIP systems on-line during PY05 was quantified to determine the impact of SGIP projects on GHG emissions. The primary GHG emitted in the U.S. is carbon dioxide (CO_2), most of which stems from fossil fuel combustion. In 2004, CO_2 represented approximately 85 percent of all U.S. GHG emissions for the year. For GHG emissions originating in the state of California, CO_2 emissions make up approximately the same percentage of total GHGs as they do for the nation—about 84 percent.[5] Other greenhouse gases primarily responsible for global climate change include methane (CH_4), nitrous oxide (N_2O), and fluorinated gases (chlorofluorocarbons [CFCs], hydrochlorofluoro-carbons [HCFCs], and halons). GHG emissions considered in this analysis focused on CO_2 and CH_4 as these are the two GHG emissions most commonly associated with SGIP project operations.

[5] California Energy Commission. Inventory of California Greenhouse Gas Emissions and Sinks: 1990 to 2004. Draft Staff Report No. CEC-600-2006-013-D. pp. 6.

A detailed examination of CO_2 emissions from SGIP systems was conducted to determine the source of any net reductions in CO_2. Table 1-8 presents estimates of CO_2 emissions associated with SGIP facilities by program incentive category and technology type.

Table 1-8: Reduction of CO_2 Emissions from SGIP Systems in 2005 (Tons of CO_2)

Program Incentive Category	Eligible Technologies	Direct Displacement from Grid	Cogen Emissions Released	Indirect Displacement through Waste Heat Recovery	Indirect Displacement from Absorption Chillers	Net CO_2 Emission Reductions
Level 1	Renewable fuel cells	1,398	-1,184	249	0	463
	Photovoltaics	40,164	0	0	0	40,164
	Wind Turbines	1,217	0	0	0	1,217
Level 2	Non-renewable fuel cells	6,216	-5,013	850	61	2,114
Level 3-R	Renewable fueled MT	4,910	-8,038	710	401	-2,016
	Renewable fueled ICE	3,971	-4,769	1,133	0	335
	Small gas turbines	0	0	0	0	0
Level 3-N	Non-renewable and waste gas fueled MT	18,231	-29,329	5,690	481	-4,927
	Non-renewable and waste gas fueled ICE	184,120	-217,227	32,266	5,425	4,583
	Small gas turbines	10,180	-16,389	7,956	-	1,747
Total	**All Technologies**	**270,407**	**-281,949**	**48,854**	**6,368**	**43,680**

Sources of CO_2 emissions include those directly displaced from the power plants in the grid through the use of SGIP generation systems; the CO_2 emissions released from the operation of SGIP projects; and the indirect displacement of CO_2 emissions from natural gas due to the use of recovered waste heat for boilers. PV and Level 3-N projects represent the largest sources of CO_2 emission reductions tied to displacement of grid power generation. Table 1-8 also shows that CO_2 emissions attributable to operation of SGIP combustion facilities (e.g., engines, microturbines, etc.) contribute more CO_2 emissions than what they displace from grid power generation.[6] In fact, if CO_2 emissions from only direct displacement of grid power and the CO_2 emissions resulting from SGIP facilities were taken into account, the SGIP would have a slightly negative overall CO_2 impact.

However, SGIP projects as a whole provide significant net reductions in CO_2 emissions. The reason for this is the reduction in CO_2 emissions due to displacement of boiler fuel from recovered waste heat by the cogeneration facilities, and displacement of electricity from waste heat driven chillers. When this displacement of boiler fuel and displaced electricity from waste heat chillers are taken into account, the net impact in CO_2 emissions increases from slightly less than a negative 12,000 tons per year to a net benefit of nearly 44,000 tons per year. As a result, the CO_2 emission benefit resulting from the SGIP is largely driven by two sources: the displacement of grid power by SGIP facilities that have no CO_2 emissions (e.g., PV and wind) and waste heat recovery operations of cogeneration facilities that displaces consumption of boiler fuel (usually natural gas).

Not all GHG emissions have similar GHG impacts. For example, methane is a very potent GHG pollutant, which has 21 times the impact as CO_2. For this reason, GHG emissions are often placed in units of CO_2 equivalent to allow a basis of comparison.

[6] Although fuel cells themselves have no CO2 emissions from the electrochemical portion of their process, there are CO2 emissions from reforming of the feedstock resource (e.g., natural gas, biogas, etc.) to produce the hydrogen needed for operation of the fuel cell.

Table 1-9 shows the tons of GHG emissions reduced in tons of CO_2 equivalent, broken down by the different SGIP incentive levels and technologies. The table also shows the net impact of GHG reductions (in tons of CO_2 equivalent) per MWhr of generated electricity.

Table 1-9: Total Net Reduction of GHG Emissions from SGIP Systems Operating During 2005 (Tons of CO_2 eq.)

<table>
<tr><th>Program Incentive Category</th><th>Eligible Technologies</th><th>Tons of GHG Emissions Reduced (in CO_2 eq.)</th><th>Energy Impact (in MWh)</th><th>Tons of GHG Reduced per MWh</th></tr>
<tr><td rowspan="3">Level 1</td><td>Renewable fuel cells</td><td>4,205</td><td>2,637</td><td>1.59</td></tr>
<tr><td>Photovoltaics</td><td>40,164</td><td>65,915</td><td>0.61</td></tr>
<tr><td>Wind Turbines</td><td>1,217</td><td>2,038</td><td>0.60</td></tr>
<tr><td>Level 2</td><td>Non-renewable fuel cells</td><td>2,114</td><td>11,164</td><td>0.19</td></tr>
<tr><td rowspan="3">Level 3-R</td><td>Renewable fueled MT</td><td>34,160</td><td rowspan="6">399,495</td><td rowspan="6">0.11*</td></tr>
<tr><td>Renewable fueled ICE</td><td>9,539</td></tr>
<tr><td>Small gas turbines</td><td>0</td></tr>
<tr><td rowspan="3">Level 3-N</td><td>Non-renewable and waste gas fueled MT</td><td>-4,927</td></tr>
<tr><td>Non-renewable and waste gas fueled ICE</td><td>4,583</td></tr>
<tr><td>Small gas turbines</td><td>1,747</td></tr>
<tr><td>Total</td><td>All Technologies</td><td>92,802</td><td>481,250</td><td>0.19</td></tr>
</table>

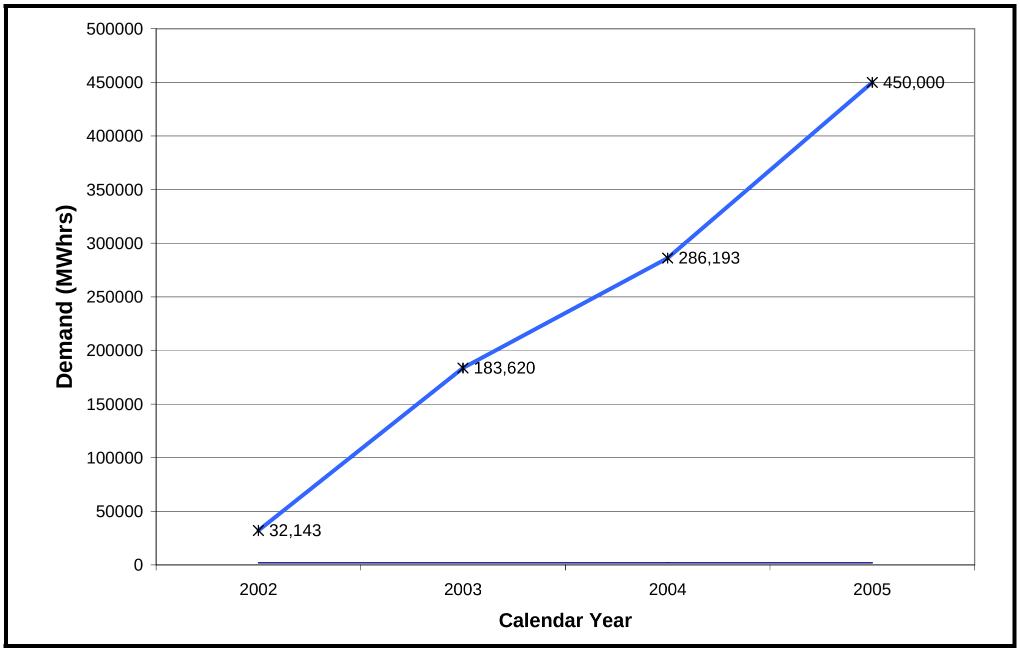
The total reduction of GHG emissions measured in CO_2 equivalent units is approximately 93,000 tons with nearly half of these reductions coming from the capture and use of methane emissions from renewable fuel use facilities in the cogeneration program. Consequently, when methane gas reduction contributions are taken into account, waste heat recovery from cogeneration projects and renewable fuel projects are responsible for the largest net reductions of GHG emissions in the SGIP.

1.3 Trends on Program Impacts

Energy and Demand

The ability of the SGIP to deliver energy has steadily increased since inception of the program. Figure 1-5 shows the increase in the amount of electricity delivered by SGIP projects annually from 2002 through the end of 2005. From 2003 on, annual electricity delivered by the SGIP has increased by over 150 percent each year.

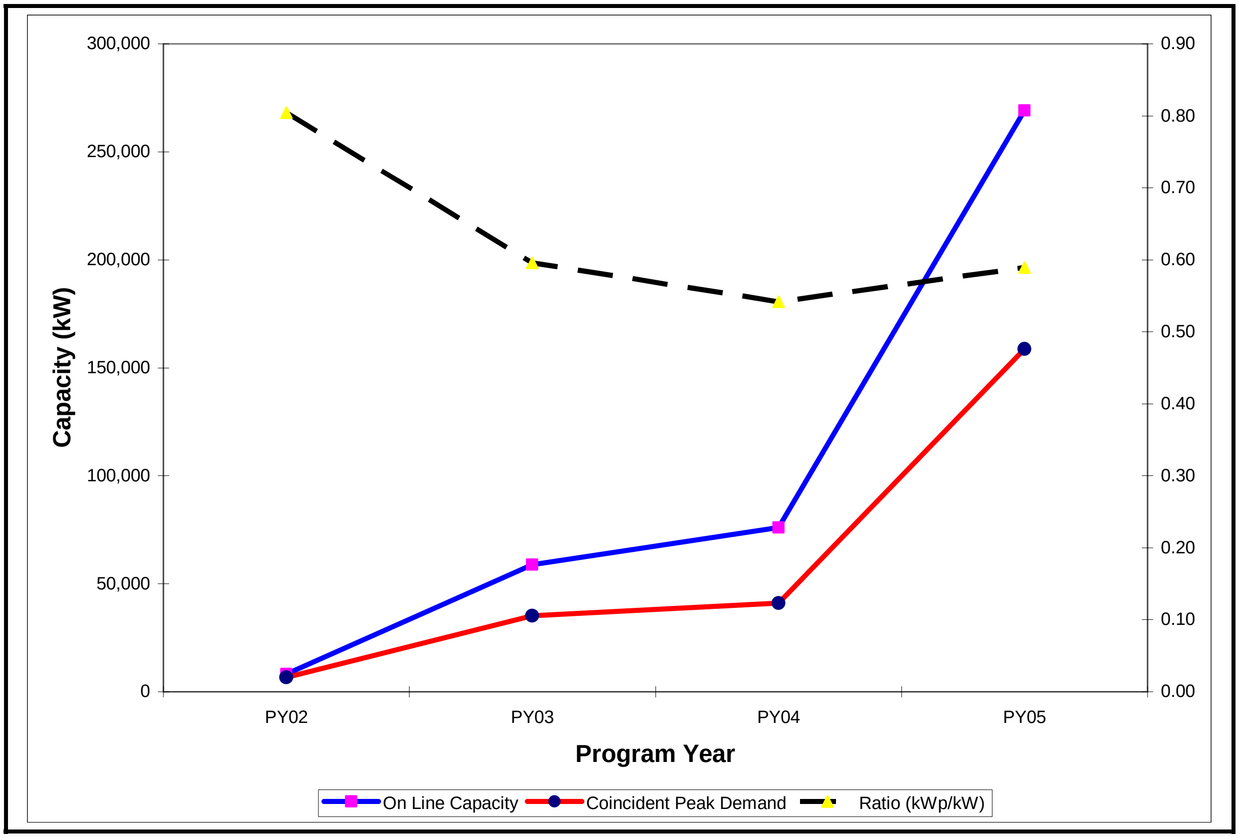
Figure 1-5: Trend in SGIP Energy Delivery from 2002 to 2005



Coincident Peak Demand

As on-line generating capacity of the SGIP has increased, so has the SGIP's ability to impact coincident peak demand. Figure 1-6 shows the change in coincident peak demand that has occurred from PY02 through the end of PY05. The ratio of peak capacity to on-line capacity (kWp/kW) reflects the amount of capacity that was actually observed to be available during the CAISO peak demand. The relatively high kWp/kW ratio observed in PY02 may be due to the low number of systems monitored during that program year. In general, the kWp/kW ratio for the SGIP has stayed between 0.5 to 0.6 since PY03. This may be reflective of the impact of PV systems, with a kWp/kW ratio that has typically ranged from 0.4 to 0.5.

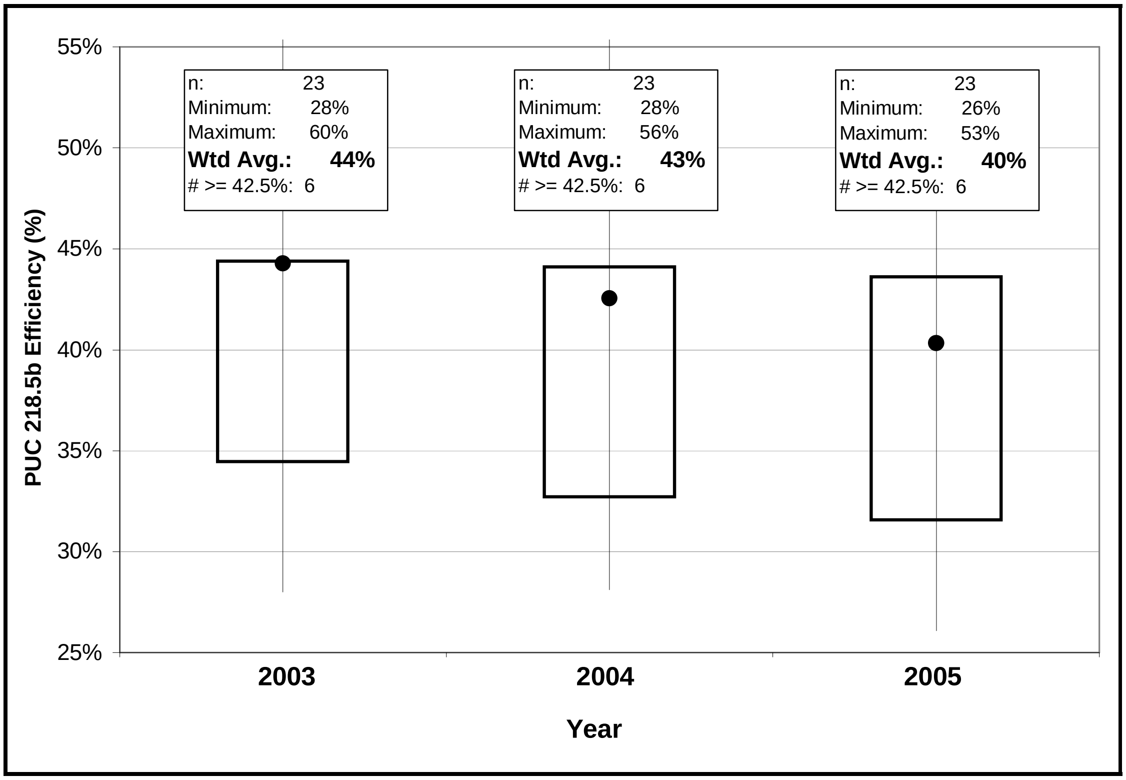
Figure 1-6: Trend on Coincident Peak Demand from PY02 to PY05



System Efficiency

Due to the large contribution that thermal cogeneration facilities have on the overall capacity of the SGIP, their efficiency greatly influences the overall SGIP efficiency. One measure of the efficiency of SGIP cogeneration facilities is their PUC 218.5 (b) efficiencies. Figure 1-7 shows the trend of PUC 218.5 (b) efficiency for Level 3/3-N cogeneration facilities. Overall, there has been a slight downward trend in efficiency of the systems. However, as indicated in a separate analysis on the efficiency and waste heat utilization of Level 3/3-N projects, a number of the SGIP projects are not achieving the required efficiency levels.[7] This may pose problems for PY06 SGIP cogeneration facilities, which are required to achieve even higher efficiency levels if they do not meet the prescribed NOx requirements.

Figure 1-7: PUC 218.5(b) Efficiency Trend from 2003 to 2005

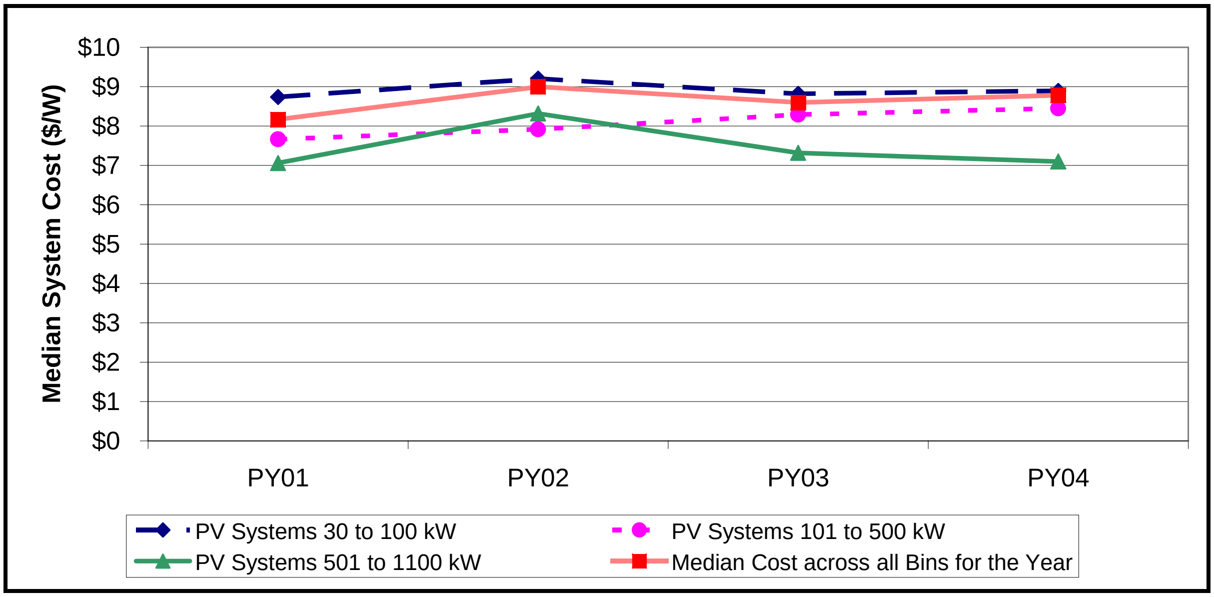


7 Itron, "CPUC Self-Generation Incentive Program: In-Depth Analysis of Useful Waste Heat Recovery and Performance of Level 3/3N Systems," August 2006.

Cost Trends

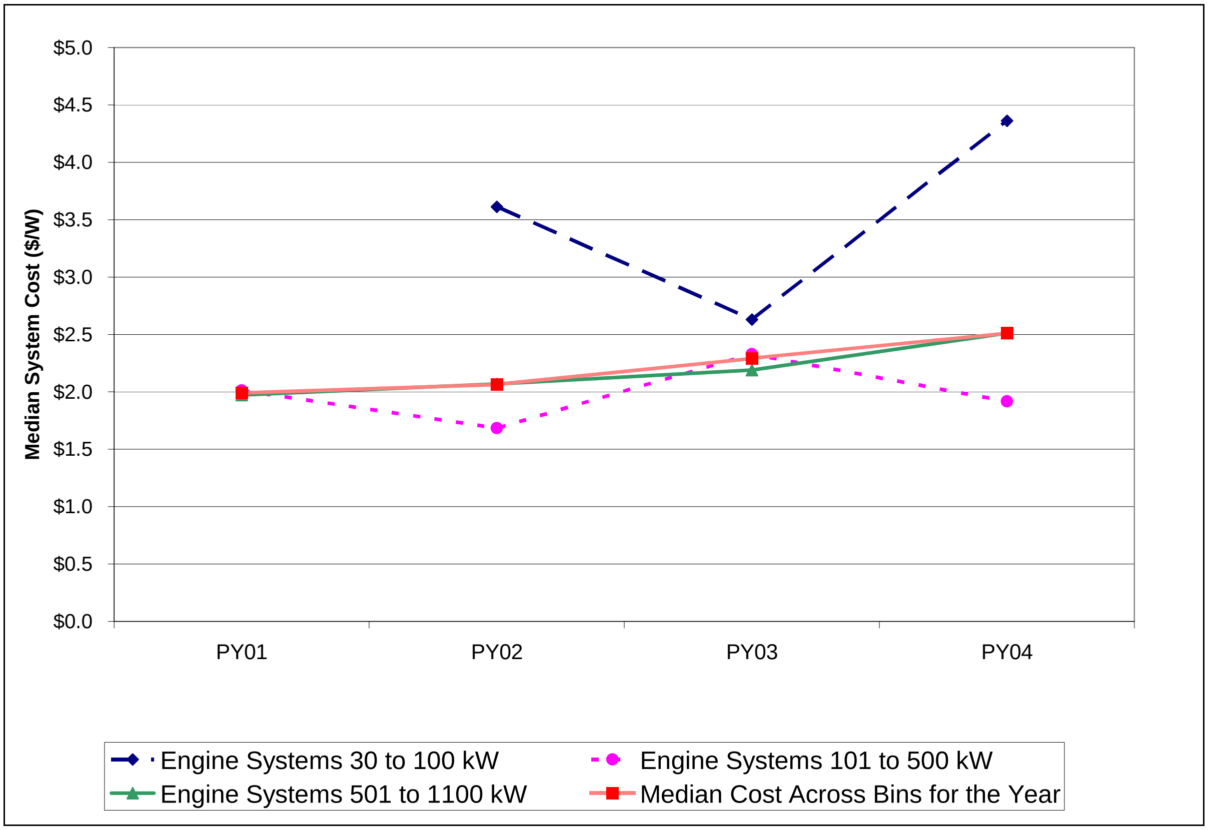
Project costs influence the SGIP in a number of ways. High project costs can reduce the cost-effectiveness of the project to the host customer and as such can influence subscription and attrition rates in the program. Similarly, low project costs can influence the types of projects that apply to the SGIP. Moreover, project costs can influence the overall cost-effectiveness of the SGIP. Figure 1-8 shows the cost trend for Complete PV projects in the SGIP from PY01 through PY04. In general, median PV costs stayed relatively unchanged over the course of the SGIP, remaining bracketed between $8 to $9 per Watt.

Figure 1-8: Cost Trend for PV Projects PY01 Through PY04



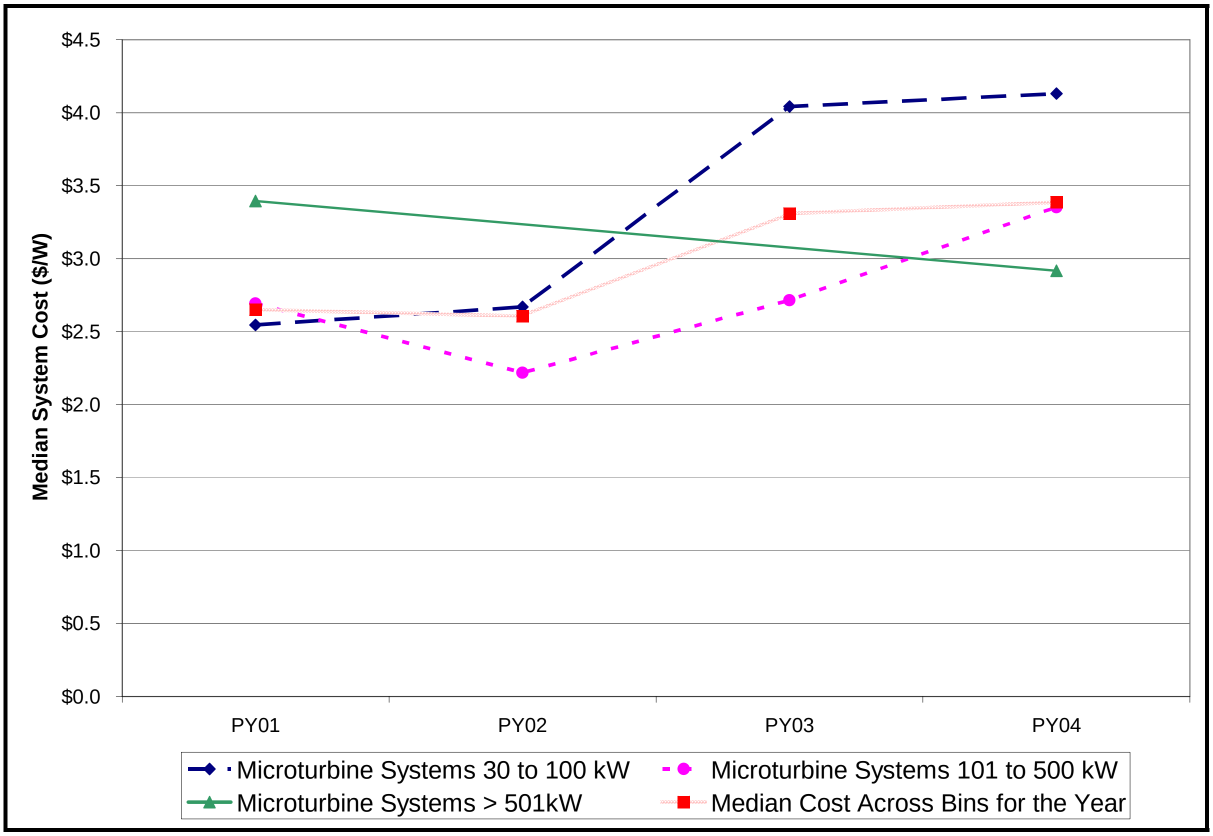
Slightly greater change in cost was seen with natural gas engines deployed under the SGIP. As shown in Figure 1-9, although there were some significant increases in costs of small engines (i.e., those in the 30 kW to 200 kW size range), overall engine costs increased moderately from $2 to $2.5 per Watt from PY01 to PY04.

Figure 1-9: Cost Trend for Natural Gas Engines PY01 Through PY04



The largest changes in costs occurred with natural gas microturbines.[8] Significant increases occurred in costs of small and medium sized microturbines, while cost reductions occurred for larger-scale microturbines. The net result was an increase in microturbine costs from a little over $2.5 per Watt in PY01 to nearly $3.5 per Watt by PY04.

Figure 1-10: Cost Trend for Natural Gas Microturbines PY01 Through PY04



1.4 Uncertainty of Results

Like all results based on sampled populations and metered data, the impact estimates provided in this report have uncertainty associated with them. At least two sources of errors introduce uncertainty into the impact estimates: measurement error and sampling error. Measurement error refers to the differences between actual values (e.g., actual electricity production) and measured values (i.e., electricity production values recorded by metering and data collection systems).

8 Very significant cost changes occurred with fuel cells from PY01 to PY04, but due to the limited number of fuel cells, the trends were not considered to be representative.

Sampling error refers to differences between actual values and values estimated for unmetered systems. The estimated impacts calculated for unmetered systems are based on the assumption that performance of unmetered systems is identical to the average performance exhibited by groups of similar metered projects. Very generally, the *central tendency* (i.e., an average) of metered systems is used as a proxy for the central tendency of unmetered systems.

For this impact evaluation an empirical approach known as Monte Carlo Simulation (MCS) analysis was used to quantify impact estimates uncertainty associated with the combined measurement and sampling errors.

Table 1-10 is a summary of the uncertainty of the peak demand estimates at a 90 percent confidence level. The table shows the range of values at a 90 percent confidence level around the central tendency ISO peak ratio and the associated precision.

Table 1-10: Uncertainty of Peak Demand Impact Results 90% Confidence

Level / Basis	ISO Peak Ratio (kW_P/kW Rebated)	90% Confidence Interval	Relative Precision
Level 1 PV	**0.45**	**0.43 to 0.47**	**±3.6%**
Metered	0.46	0.46 to 0.46	±0.1%
Estimated	0.44	0.41 to 0.47	±7.6%
Level 3/3N/3R	**0.64**	**0.60 to 0.68**	**±5.6%**
Metered	0.67	0.67 to 0.67	±0.1%
Estimated	0.61	0.54 to 0.68	±11.0%

Table 1-11 summarizes the uncertainty of the average annual capacity factors for Level 1 PV and Level 3/3N/3R cogeneration facilities in the SGIP at a 90 percent confidence level.

Table 1-11: Uncertainty of Annual Energy Results 90% Confidence

Level / Basis	Annual Capacity Factor	90% Confidence Interval	Precision
Level 1 PV	**0.157**	**0.153 to 0.161**	**±2.6%**
Metered	0.164	0.164 to 0.164	±0.1%
Estimated	0.154	0.147 to 0.160	±4.0%
Level 3/3N/3R	**0.42**	**0.39 to 0.46**	**±8.2%**
Metered	0.46	0.46 to 0.46	±0.1%
Estimated	0.40	0.35 to 0.45	±14.0%

Table 1-12 summarizes the uncertainty associated with the impact results tied to energy efficiency and waste heat utilization targets required for SGIP cogeneration facilities under Public Utilities Code 218.5 at a 90 percent confidence level. The reported results represent a weighted average of all cogeneration systems in the program. The code requires a system efficiency of at least 42.5 percent.

Table 1-12: Uncertainty of PUC 218.5(b) Results 90% Confidence

Level / Basis	218.5(b) Efficiency	90% Confidence Interval	Relative Precision
Level 3/3N	**40%**	**38% to 42%**	**4.4%**
Metered	40%	38% to 41%	3.4%
Estimated	40%	38% to 42%	5.3%

2

Introduction

2.1 Program Background

The Self-Generation Incentive Program (SGIP) was established in response to Assembly Bill (AB) 970[1], which required the California Public Utilities Commission (CPUC) to initiate certain load control and distributed generation program activities. The CPUC issued Decision 01-03-073 (D.01-03-073) on March 27, 2001 outlining provisions of a distributed generation program. The Decision mandated implementation of a self-generation program designed to produce significant public (e.g., environmental and energy distribution system) benefits for all ratepayers, including gas ratepayers across the service territories of California's investor-owned utilities (IOUs). The resulting SGIP offered financial incentives to customers of IOUs who installed certain types of distributed generation (DG) facilities to meet all or a portion of their energy needs. DG technologies eligible under the SGIP included solar photovoltaic systems, fossil-and renewable-fueled reciprocating engines, fuel cells, micro-turbines, small-scale gas turbines; and wind energy systems.

In October of 2003, AB 1685 extended the SGIP beyond 2004 through 2007. This bill required the CPUC, in consultation with the CEC, to administer, until January 1, 2008, the SGIP for distributed generation resources in largely the same form that existed on January 1, 2004. However, this decision notwithstanding, a number of program modifications have been made in the 2004 and 2007 period. For example, with the funding of the California Solar Initiative (CSI), the SGIP will no longer offer incentives to photovoltaics (PV) after 2006. AB 2778, approved in September of 2006, continues the SGIP for fuel cells and wind technology until 2012. However, other renewable technologies such as micro-hydropower were not included. Moreover, cogeneration systems are no longer funded beyond 2007. The future program design details have yet to be worked out, but there is some suggestion that cogeneration may be revisited. Upon enacting AB 2778, Governor Schwarzenegger encouraged parties to revisit the eligibility of the eliminated technologies in the following signing message: "This bill extends the sunset of the Self Generation Incentive Program to promote distributed generation throughout California. However, the legislation eliminated clean combustion technologies like microturbines from the program. I look forward to working with the Legislature to enact legislation that returns the most efficient and cost

[1] Assembly Bill 970 (Ducheny, September 7, 2000)

effective technologies to the program. If clean up legislation is not possible, the California Public Utilities Commission should develop a complimentary program for these technologies."

The SGIP has been operational since July 2001 and represents the single largest DG incentive program in the country. As of December 31, 2005, over $270 million in incentives had been paid out through the SGIP, which resulted in the installation of nearly 700 DG projects representing approximately 190 megawatts (MW) of rebated capacity.

2.2 Impact Evaluation Requirements

The CPUC Decision (D.01-03-073) authorizing the SGIP states: "Program administrators shall outsource to independent consultants or contractors all program evaluation activities…" Impact evaluations were among the evaluation activities outsourced to independent consultants. The Decision also directed the assigned Administrative Law Judge, in consultation with the CPUC Energy Division and the Program Administrators (PAs) to establish a schedule for filing the required evaluation reports. Table 2-1 lists the SGIP impact evaluation reports filed with the CPUC prior to 2005.

Table 2-1: SGIP Impact Evaluation Reports Prepared to Date

Calendar Year Covered	Date of Report
2001[2]	June 28, 2002
2002[3]	April 17, 2003
2003[4]	October 29, 2004
2004[5]	April 15, 2005

On March 8, 2006, the PAs filed a motion with the CPUC proposing a schedule of measurement and evaluation (M&E) activities for 2006 and 2007. In a May 18, 2006 ruling, the CPUC provided guidance to the PAs on the schedule of filings for impacts evaluation reports through 2008. Table 2-2 identifies the schedule for filing of the upcoming impacts evaluation reports.

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2 California Self-Generation Incentive Program: First Year Impact Evaluation Report. Submitted to Southern California Edison. Prepared by Regional Economic Research (RER), June 28, 2002.

3 California Self-Generation Incentive Program: Second Year Impact Evaluation Report. Submitted to Southern California Edison. Prepared by Itron, Inc., April 17, 2003.

4 CPUC Self-Generation Incentive Program: Third Year Impact Assessment Report. Submitted to The Self-Generation Incentive Program Working Group. Prepared by Itron, Inc., October 29, 2004.

5 California Self-Generation Incentive Program: Fourth Year Impact Evaluation Report. Submitted to Southern California Edison. Prepared by Itron, Inc., April 15, 2005.

Table 2-2: Post-2005 SGIP Impact Evaluation Reports

Calendar Year Covered	Date of Report Filing to the CPUC
2005	March 1, 2007
2006	August 31, 2007
2007	June 16, 2008
2008	June 15, 2009

This report provides the findings of an impact evaluation of the fifth program year of the SGIP covering the 2005 calendar year.

2.3 Scope of the Report

The 2005 Impact Evaluation Report represents the fifth impact evaluation report conducted under the SGIP. At the most fundamental level, the overall purpose of all annual SGIP impact evaluation analyses is identical: to produce information that helps the many SGIP stakeholders make informed decisions about the SGIP's design and implementation. As the SGIP has evolved over time, the focus and depth of the impact evaluation reports have changed appropriately. Like prior impact evaluation reports, the 2005 report examines the effects of SGIP technologies on electricity production and demand reduction at different time periods, on system reliability and operation, and on compliance with renewable fuel use and thermal energy efficiency requirements. In addition, the 2005 report also examines greenhouse gas emission reductions associated with each SGIP technology category. SGIP impacts on transmission and distribution (T&D) system operation and reliability are an important element of the impact evaluation. However, due to the time involved in obtaining and treating the necessary T&D data sets from the utilities, this element could not be included in the 2005 Impact Evaluation Report. Impact assessments of SGIP projects on the T&D system will be provided in the 2006 Impact Evaluation Report.

Table 2-3 summarizes the impact evaluation objectives contained in the 2005 report.

Table 2-3: Impact Evaluation Objectives in 2005 Report

Impact Evaluation Objectives Addressed in 2005 Impacts Evaluation Report
Electricity energy production and demand reduction ▪ Annual production and production at peak periods during summer (both at Cal ISO system and at individual IOU-specific summer peaks) ▪ Peak demand impacts (both at Cal ISO system and at individual IOU-specific summer peaks) ▪ Combined by technology category and by individual technology category
Reliability by technology category will be assessed ▪ Extent of SGIP technology operation during Cal ISO peak ▪ Checked against available failure information ▪ Operating patterns of cogeneration systems
Compliance of Level 2 and Level 3/3N technologies will be assessed against PUC 218.5 requirements ▪ PUC 218.5 (a): useful recovered waste heat requirements ▪ PUC 218.5 (b): system efficiency requirements
Compliance of Level 1 and Level 3R systems with renewable fuel use requirements will be assessed
Assessment of incremental costs due to renewable fuel clean-up equipment costs for Level 2 systems
Provide greenhouse gas emission reductions by SGIP technology ▪ Net against CO_2 emissions generated otherwise from grid generation ▪ Methane captured by renewable fuel use projects
Trending of performance by SGIP technology from 2002 - 2005

Impacts are assessed at a mix of program-wide or PA-specific levels within the report. Table 2-4 identifies the level at which impact evaluation objectives are assessed in the 2005 report.

Table 2-4: Level of 2005 Impact Evaluation Objectives

Impact Evaluation Objectives Addressed in 2005 Impact Evaluation Report	Level at Which Impact is Addressed in 2005 Impact Evaluation Report	
	Program Wide	PA-Specific
Electricity energy production and demand reduction ▪ By specific time periods ▪ By technology category	Yes	Yes
Operating and reliability statistics by technology category	Yes	No
Compliance with thermal energy utilization and system efficiency program requirements	Yes	No
Compliance of Level 2 fuel cells with renewable fuel use requirements	Yes	Yes
Review renewable fuel clean-up equipment costs for Level 2 systems	Yes	No
Determine greenhouse gas emission reductions by technology category	Yes	Yes
Performance trends of individual projects over time	Yes	No

Incentive payments made under the SGIP are tied to specific technology categories and levels. DG technologies covered under the incentive levels and the incentive payments for those levels have changed over time. Table 2-5 identifies the DG technologies and incentive payments used for SGIP projects coming on-line in 2005.

Table 2-5: Summary of SGIP Design for Projects On-Line as of 12/31/2005

Program Incentive Category	Eligible Generation Technologies	Incentive Offered ($/watt)	Minimum System Size	Maximum System Size	Maximum Incentive Size
Level 1	Renewable fuel cells	$4.50	30 kW	5 MW	1 MW
Level 1	Photovoltaics (PV)	$3.50	30 kW	5 MW	1 MW
Level 1	Wind Turbines	$1.50	30 kW	5 MW	1 MW
Level 2	Non-renewable fuel cells	$2.50	None	5 MW	1 MW
Level 3[6]	Non-renewable internal combustion engines and microturbines	NA	NA	NA	NA
Level 3-R	Renewable-fueled microturbines	$1.00	None	5 MW	1 MW
Level 3-R	Renewable-fueled internal combustion engines and small gas turbines	$1.00	None	5 MW	1 MW
Level 3-N	Non-renewable- and waste gas-fueled microturbines	$0.80	None	5 MW	1 MW
Level 3-N	Non-renewable- and waste gas-fueled internal combustion engines and small gas turbines	$0.60	None	5 MW	1 MW

For each of these incentive levels and eligible technologies the SGIP incentive was limited to the first 1,000 kW of system capacity.[7] For the remainder of this report, microturbines and small gas turbines are collectively referred to as "turbines," while reciprocating internal combustion engines (ICE) are simply referred to as "engines."

[6] The SGIP moved away from Level 3 technologies in the 2005 Handbook but are included in this table as Level 3 technologies deployed in earlier program years had impacts during 2005.

[7] CPUC Rulings increased the eligible maximum system size beyond 1,000 kW – although the maximum incentives basis remains capped at 1,000 kW.

2.4 Report Organization

This report is organized into eight sections, as described below.

- **Section 1** provides an executive summary of the key objectives and findings of this fifth-year impact evaluation of the SGIP through the end of 2005.
- **Section 2** is this introduction.
- **Section 3** presents a summary of the program status of the SGIP through the end of 2005.
- **Section 4** provides characterization of typical operating profiles of different DG technologies installed under the SGIP.
- **Section 5** discusses the 2005 impacts associated with SGIP projects at the program level. The section provides a summary discussion as well as specific information on impacts associated with energy delivery; peak demand reduction; efficiency and waste heat utilization requirements; renewable fuel use requirements; and greenhouse gas emission reductions.
- **Section 6** discusses the impacts of the SGIP.
- **Section 7** addresses the system monitoring and operational data collection efforts.
- **Section 8** discusses approaches used for estimating the uncertainty of the impact evaluation results.
- **Appendix A** contains all of the Performance Distributions used for the Monte Carlo Simulations discussed in Section 8.
- **Appendix B** describes the methodology used for developing estimates of SGIP greenhouse gas emission impacts.

3

Program Status Overview

3.1 Introduction

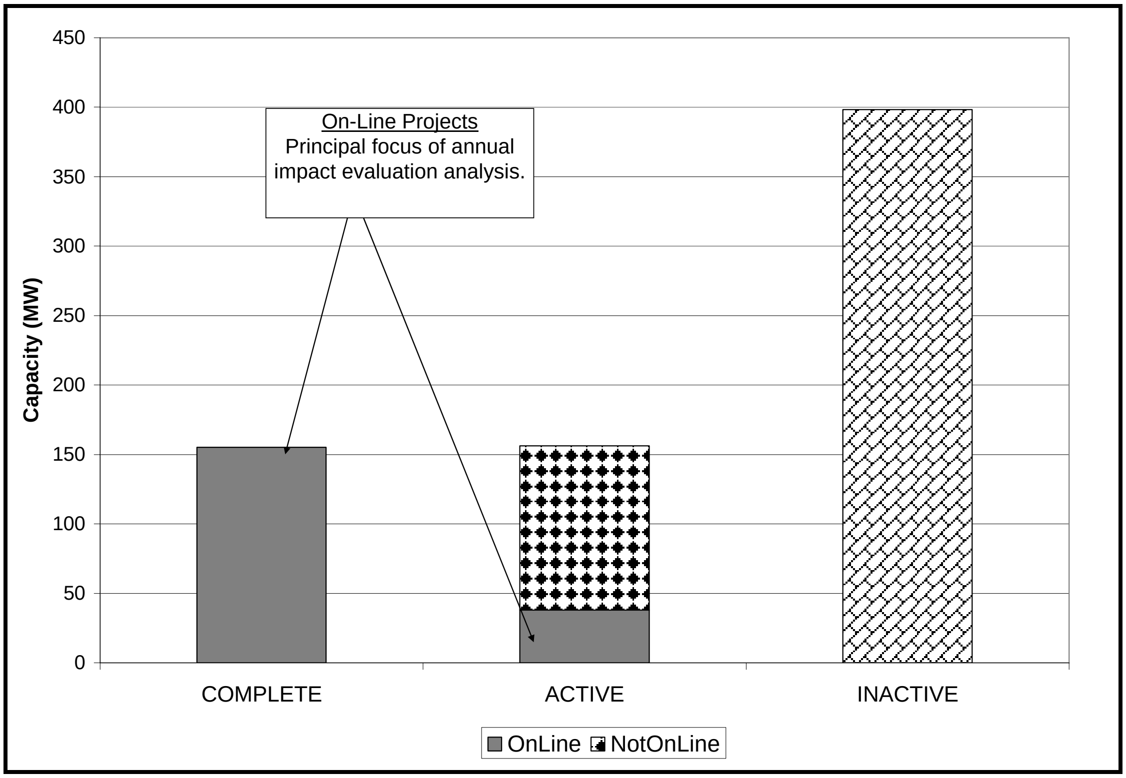
This section provides information on the status of the Self-Generation Incentive Program (SGIP) relative to all applications extending from Program Year (PY) 01 through the end of PY05 based on PA tracking data available through December 31, 2005. Information in this section includes the status of projects in the SGIP, the associated amount of system capacity; incentives paid or reserved, and project costs.

3.2 Overview

Figure 3-1 summarizes the status of SGIP projects at a very high level. It shows the status of projects by their stage of progress within the SGIP implementation process and their "on-line" status. "On-line" projects are defined as those that have entered normal operations (i.e., projects are through the shakedown or testing phase and are expected to be providing energy on a relatively consistent basis).[1]

[1] The reference to having entered 'normal operations' is not an indication that a system is actually running during any given hour of the year. For example, some systems that have entered normal operations do not run on weekends.

Figure 3-1: Summary of PY01-PY05 SGIP Project Status as of 12/31/2005



Key stages in the SGIP implementation process include:

- ***Complete Projects:*** The generation system has been installed and verified through on-site inspections and an incentive check has been issued. Projects meeting these requirements are considered “on-line” for impact evaluation purposes.
- ***Active Projects:*** These represent SGIP projects that have not been withdrawn, rejected, completed, or placed on a wait list.[2] As time goes on the active projects will migrate either to the Complete or to the Inactive category. Some, but not most, of these projects had entered normal operations as of the end of 2005, but were not considered Complete, as an incentive check had not yet been issued.
- ***Inactive Projects:*** Projects that have been withdrawn by the applicants or rejected by the PAs, and are no longer progressing in the SGIP implementation process.

[2] When SGIP funding has been exhausted, eligible projects are placed on a wait list within the relevant incentive level has been exhausted for that Program Year. Previously, projects that remained on a wait list at the end of the Program Year were required to re-apply for funding for the subsequent funding cycle. This requirement was eliminated in December 2004 by D.04-12-045. Over time, these projects will be withdrawn or rejected and replaced by projects from the wait list.

Table 3-1 provides a breakdown by incentive level of the Complete and Active projects depicted graphically in Figure 3-1 on the previous page.

Table 3-1: Quantity and Capacity of Complete and Active Projects

Incentive Level	Technology	Complete		Active (All)		Total		
		(n)	(MW)	(n)	(MW)	(n)	(MW)	Avg Size (kW)
1	Photovoltaic	484	55.6	330	56.1	814	111.7	137
	Wind Turbine	2	1.6	1	0.6	3	2.3	764
	Renewable Fuel Cell	2	0.8	0	0.0	2	0.8	375
2	Non-Renewable Fuel Cell	3	1.8	9	6.0	12	7.8	646
3	Engine/Turbine/Fuel Cell	91	44.7	7	3.1	98	47.9	488
3-N	Non-Renewable Engine/Turbine	105	48.5	133	79.7	238	128.2	539
3-R	Renewable Engine/Turbine	11	2.2	21	10.6	32	12.8	399
Total	**Total**	**698**	**155.2**	**501**	**156.1**	**1199**	**311.3**	**260**

There were nearly 1200 Complete and Active projects, representing over 311 MW of capacity in the SGIP by December 31, 2005. However, the principal focus of the 2005 impact evaluation is a subset of these projects (i.e., Complete and Active projects that were "on-line" by December 31, 2005).

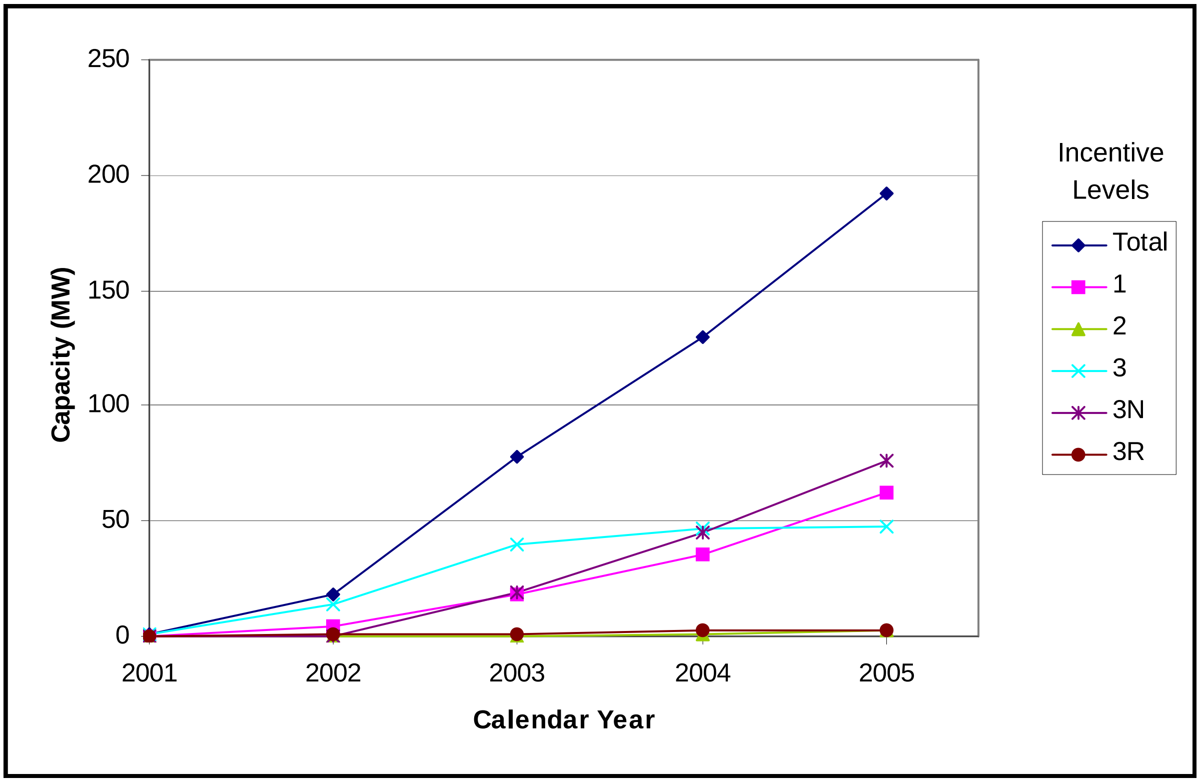
Table 3-2 provides information on the number and capacity of projects that are "on-line" even if they have not received incentive checks. The information is broken down by incentive level, technology type, and stage of implementation in the SGIP. By the end of 2005, "on-line" projects represented over 780 projects and approximately 190 MW of rebated capacity.

Table 3-2: Quantity and Capacity of Projects On-Line as of 12/31/2005

Incentive Level	Technology	Complete		Active (On-Line)		Total On-Line Projects		
		(n)	(MW)	(n)	(MW)	(n)	(MW)	Avg Size (kW)
1	Photovoltaic	484	55.6	37	4.2	521	59.8	115
	Wind Turbine	2	1.6	0	0.0	2	1.6	824
	Renewable Fuel Cell	2	0.8	0	0.0	2	0.8	375
2	Non-Renewable Fuel Cell	3	1.8	1	1.0	4	2.8	700
3	Engine/Turbine/Fuel Cell	91	44.7	4	2.5	95	47.3	497
3-N	Non-Renewable Engine/Turbine	105	48.5	42	29.5	147	78.0	530
3-R	Renewable Engine/Turbine	11	2.2	3	0.8	14	2.9	209
Total	**Total**	**698**	**155.2**	**87**	**37.9**	**785**	**193.1**	**246**

Figure 3-2 shows the increase in rebated capacity of Complete projects extending from 2001 through the end of 2005 by incentive level. The capacity of all Complete projects more than tripled between the start of 2003 and the end of 2005. Almost equal contributions in capacity occurred between Levels 1, 3, and 3-N projects. Although there were substantially more PV projects installed during this time than cogeneration (Levels 3 and 3-N) projects, the smaller average size of the PV projects lowered the annual capacity contribution of PV projects.[3]

Figure 3-2: Growth in On-Line Project Capacity from 2001-2005



Customers of the investor-owned utilities (IOUs) fund the SGIP through a cost recovery process administered by the CPUC. Every IOU customer is eligible to participate in the SGIP. In some cases, these same IOU customers are also customers of municipal utilities. Consequently, deployed SGIP projects can have impacts on both IOU and municipal utilities.

[3] From PY03 to PY05, the number of Complete PV projects increased from 117 to 488, while Complete 3 and 3-N projects increased from 65 to 196 projects.

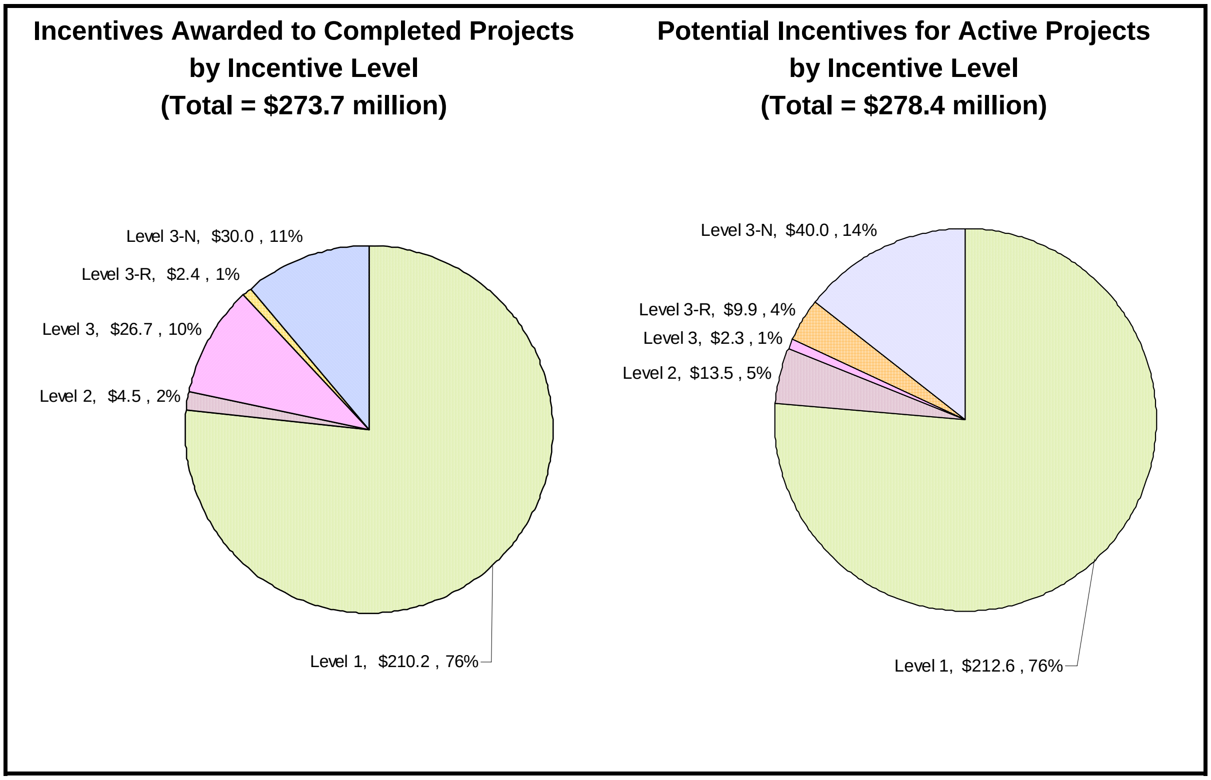
Table 3-3 shows the number of SGIP projects where the host site is an electric customer of an IOU or municipal utility. Generally, the largest project capacity overlap between IOU and municipal utilities occurs with PV systems. At the end of 2005, approximately 17 percent of the rebated PV capacity in the SGIP represented systems installed by sites that were also customers of municipal utilities. In contrast, approximately three percent of cogeneration (Level 3 and 3-N) projects were dual-utility customers. Fifty-five of the 72 Level 1 PV projects involving a municipal utility customer correspond to SoCalGas SGIP projects. Most of these projects were supported by the SGIP as well as by a solar PV program offered by the municipal utility.

Table 3-3: Electric Utility Type for Projects On-Line as of 12/31/2005

Incentive Level	Technology	IOU		Municipal		Total On-Line	
		(n)	(MW)	(n)	(MW)	(n)	(MW)
1	Photovoltaic	449	49.9	72	9.9	521	59.8
	Wind Turbine	2	1.6	0	0.0	2	1.6
	Renewable Fuel Cell	2	0.8	0	0.0	2	0.8
2	Non-Renewable Fuel Cell	4	2.8	0	0.0	4	2.8
3	Engine/Turbine/Fuel Cell	90	45.9	5	1.3	95	47.3
3-N	Non-Renewable Engine/Turbine	142	75.6	5	2.3	147	78.0
3-R	Renewable Engine/Turbine	14	2.9	0	0.0	14	2.9
Total	**Total**	**703**	**179.6**	**82**	**13.6**	**785**	**193.1**

Another way to identify project status within the SGIP is by the stage of incentive payment. Incentives are reserved for Active projects, conversely incentives are paid for Completed projects. PAs can use incentive payment status to examine the funding backlog of SGIP projects by incentive level. Figure 3-3 summarizes SGIP incentives paid or reserved as of December 31, 2005. By the end of PY05, over $270 million in incentive payments had been paid to Complete projects. The reserved backlog represented nearly twice that amount at a total of nearly $500 million.

Figure 3-3: Incentives Paid or Reserved for Complete and Active Projects



3.3 Characteristics of Complete and Active Projects

Key characteristics of Complete and Active projects include system capacity and project costs.

System Size (Capacity)

Table 3-4 summarizes the system capacity characteristics of all Complete projects by technology and incentive level. Generally, engines deployed under the SGIP tend to have the largest installed capacities followed by gas turbines. Maximum capacities for engines and gas turbines exceeded 1 MW, with average sizes of approximately 660 kW and 1.3 MW, respectively. Median and mean values indicate that while there are some large (i.e., greater than one MW) PV systems installed under the SGIP, most tend to be less than 150 kW in capacity. Similarly, microturbines deployed by December 31, 2005 under the SGIP tended to be less than 170 kW in capacity. The few wind and fuel cell systems deployed under the SGIP by the end of PY05 were medium-sized facilities with capacities of less than 1 MW.

Table 3-4: Installed Capacities of PY01-PY05 Projects Completed by 12/31/2005

Incentive Level	Technology	System Size (kW)				
		n	Mean	Minimum	Median	Maximum
1	Photovoltaic	484	115	28	59	1050
	Wind Turbine	2	824	699	824	950
	Fuel Cell	2	375	250	375	500
2	Fuel Cell	3	600	200	600	1000
3	Engine	59	664	60	600	1500
	Microturbine	31	135	28	100	600
	Gas Turbine	1	1383	1383	1383	1383
3-N	Engine	63	652	60	540	1500
	Microturbine	41	152	58	120	600
	Gas Turbine	1	1210	1210	1210	1210
3-R	Engine	1	500	500	500	500
	Microturbine	10	167	60	80	420

System capacities of Active projects may indicate incipient changes in SGIP project capacities. If a large number of Active projects have larger capacities than their Complete project technology counterparts, migration of these Active projects into the Complete project category will act to increase the average installed capacity. This is important because impacts from technologies are more affected by capacity than number of projects.

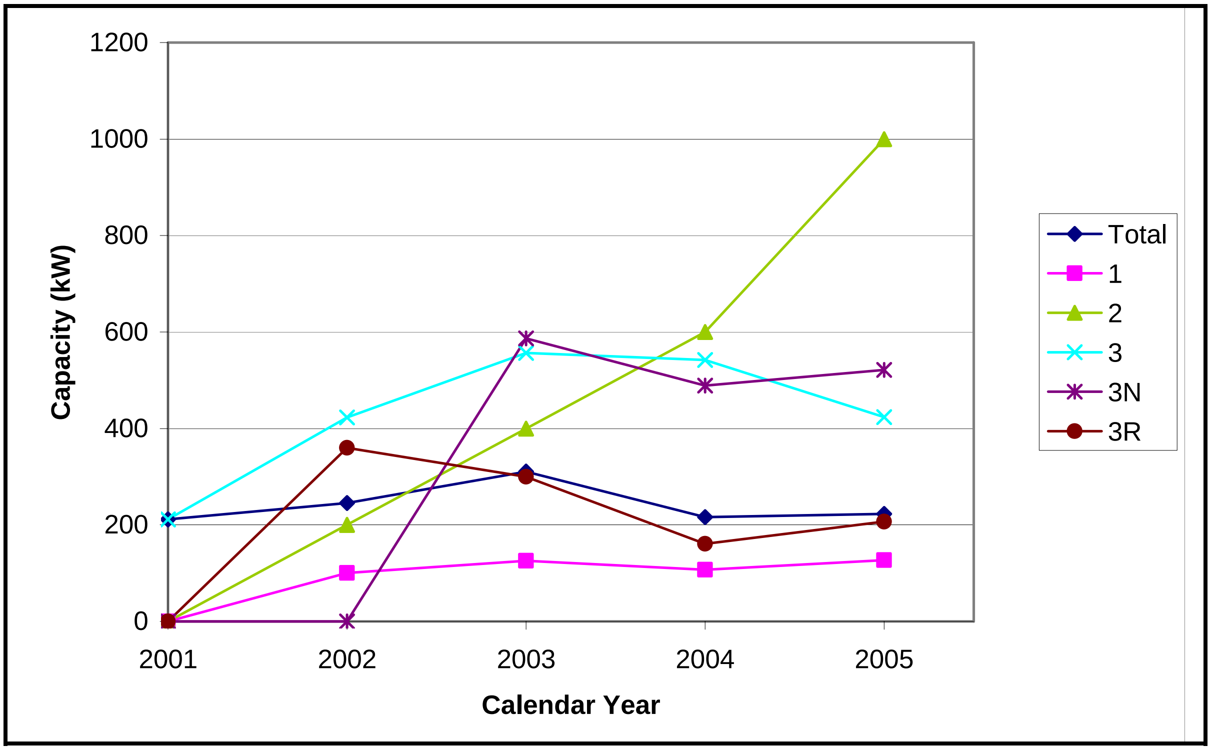
Table 3-5 summarizes the system capacity characteristics of Active projects by technology and incentive level. In general, the rated capacities of Active projects tend to be greater than their Complete project technology counterparts; therefore, the capacity of SGIP projects overall can be expected to increase as these larger, Active projects migrate to the Completed status.

Table 3-5: Rated Capacities of PY01-PY05 Projects Active as of 12/31/2005

Incentive Level	Technology	System Size (kW)				
		n	Mean	Minimum	Median	Maximum
1	Photovoltaic	330	170	30	69	1009
	Wind Turbine	1	642	642	642	642
	Fuel Cell	0	0	0	0	0
2	Fuel Cell	9	661	200	500	1000
3	Engine	7	447	150	375	1406
	Microturbine	0	0	0	0	0
	Gas Turbine	0	0	0	0	0
3-N	Engine	88	661	30	400	4110
	Microturbine	39	186	58	120	960
	Gas Turbine	6	2382	170	2462	4527
3-R	Engine	13	644	80	500	1516
	Microturbine	8	279	30	225	750

Figure 3-4 shows the trend of capacity for Complete projects from 2001 through the end of 2005. Largest increases in capacities occurred with Level 2 fuel cells, while Level 3-R renewable fuels technologies showed a steady decrease in capacity from PY02-05. Level 3-N projects (comprised of IC engines, gas turbines and microturbines) showed a decrease in capacity from 2003 to 2004, and then rose slightly from 2004 to 2005 before flattening out at approximately 490 kW. Average capacities of Level 1 PV technologies ranged between 110 to 130 kW from 2002 through the end of 2005. The net result has been that the average overall capacity of SGIP projects increased slightly from 2002 to 2003, but decreased back down from 2004 and 2005 to an average capacity of approximately 220 kW.

Figure 3-4: Trend of Capacity of Complete Projects from PY01-PY05



Total Eligible Project Costs

Total eligible project costs are regulated by SGIP guidelines and reflect the costs of the installed generating system and its ancillary equipment. Table 3-6 provides total and average project cost data for Complete and Active projects from PY01 through PY05. Average per-Watt eligible project costs represent capacity-weighted averages.

By the end of PY05, total eligible project costs (private investment plus the potential SGIP incentive) corresponding to Complete projects exceeded $700 million. At a Complete project cost of approximately $460 million, PV projects account for the vast majority (65 percent) of total eligible Complete project costs. Similarly, PV projects represent the single largest project cost category in either the Complete or Active project categories. From a system capacity perspective, PV projects made up approximately 36 percent of the total Complete project capacity installed through PY05. The combined costs of Level 3 and 3-N engines account for the second highest total Complete project costs at $214 million (approximately 30 percent of the total eligible project costs), and correspond to 52 percent of the total Complete project installed capacity.

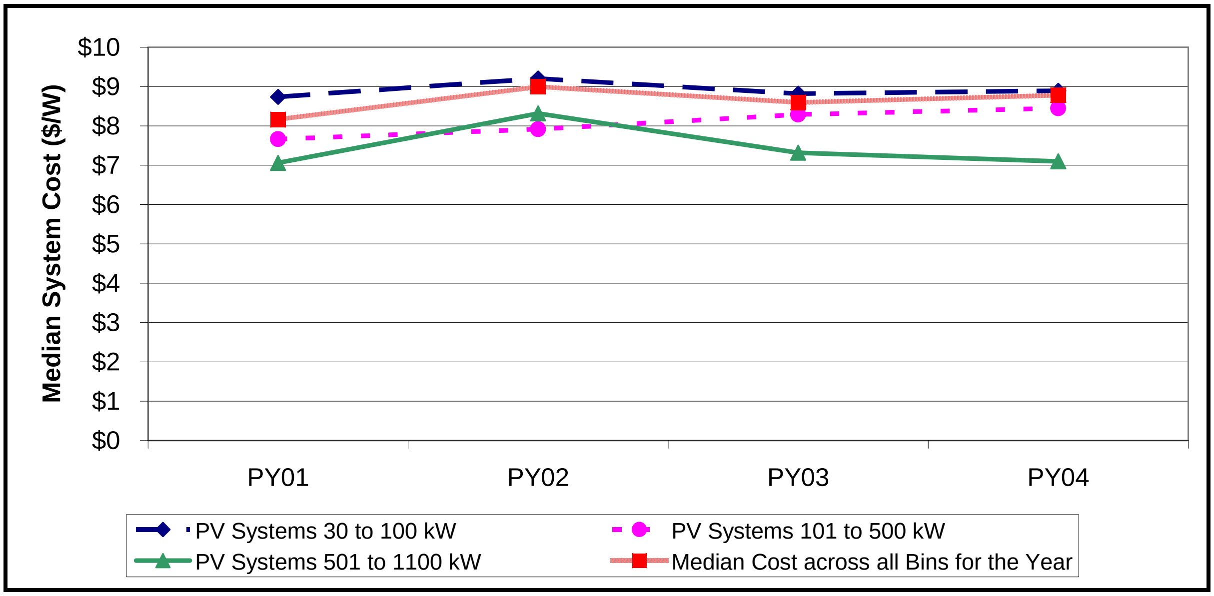
On an average cost-per-installed-Watt ($/Watt)-basis, fuel cell and PV projects are more costly than engine and microturbine projects. However, any comparison of these project costs must take into consideration the fundamentally different characteristics of the technologies. In the case of cogeneration projects fueled with natural gas, ongoing fuel purchase and maintenance costs account for the majority of the lifecycle cost of ownership and operation. For PV systems, the capital cost is by far the most significant cost component while the fuel is free and operations and maintenance costs are generally not as significant as those of cogeneration systems. Similarly, fuel cells, although having high upfront capital costs, operate at very high efficiencies (which reduce fuel requirements) and with very low air emissions (which precludes the need for expensive pollution control equipment).

Table 3-6: Total Eligible Project Costs of PY01–PY05 Projects

Incentive Level	Technology	Complete			Active		
		Total (MW)	Wt.Avg. ($/W)	Total ($ MM)	Total (MW)	Wt.Avg. ($/W)	Total ($ MM)
1	PV	55.6	$8.25	$459	56.1	$8.63	$484
	Wind Turbine	1.6	$4.11	$7	0.6	$2.58	$2
	Fuel Cell	0.8	$9.70	$7	0.0	$0.00	$0
2	Fuel Cell	1.8	$8.34	$15	6.0	$6.66	$40
3	Engine	39.2	$2.10	$82	3.1	$2.64	$8
	Microturbine	4.2	$3.02	$13	0.0	$0.00	$0
	Gas Turbine	1.4	$2.70	$4	0.0	$0.00	$0
3-N	Engine	41.1	$2.18	$90	58.1	$2.37	$138
	Microturbine	6.2	$3.17	$20	7.3	$2.97	$22
	Gas Turbine	1.2	$3.87	$5	14.3	$2.09	$30
3-R	Engine	0.5	$2.79	$1	8.4	$2.60	$22
	Microturbine	1.7	$3.12	$5	2.2	$3.89	$9
Total	**Total**	**155.2**	**53.4**	**706.6**	**156.1**	**34.4**	**753.3**

Cost trends for Complete PV projects between PY01 through PY05 are shown in Figure 3-5. The cost trends are provided in terms of the median cost-per-Watt of rebated capacity. Several observations can be made from the PV cost trends. First, the overall median PV cost stayed between \$8 to \$9 per Watt from PY01 through PY05. Second, the smallest-sized PV systems (i.e., those between 30 to 100 kW) had the least change in cost over the four program years. Third, the largest PV systems (i.e., those between 500 to 1100 kW) had the greatest change in cost and also ended up with the lowest installed costs by the end of 2005 (at \$7.10 per Watt).

Figure 3-5: Cost Trend of Complete PV Projects



Cost trends for Complete natural gas-fired engines are shown in Figure 3-6. Median project costs for medium to larger-sized engines (i.e., those between 100 kW to over 1 MW) showed relatively slow increases from PY01 through PY04. The costs of smaller systems increased substantially over the four program years, even though there were decreases in costs during PY02 to PY03. The dip and rise in costs for the smaller IC engines can be attributed to learning curves associated with the emergence of new systems in the marketplace. The engines that are the first to emerge generally represent prototypes equipped with significant monitoring or other extra features that tend to drive up the capital costs. The prototypes are replaced by lower cost, more "commercial" systems. However, as the technologies are still new, costs have increased to resolve operational issues as they are discovered.

Figure 3-6: Cost Trend of Complete Natural Gas Engine Projects

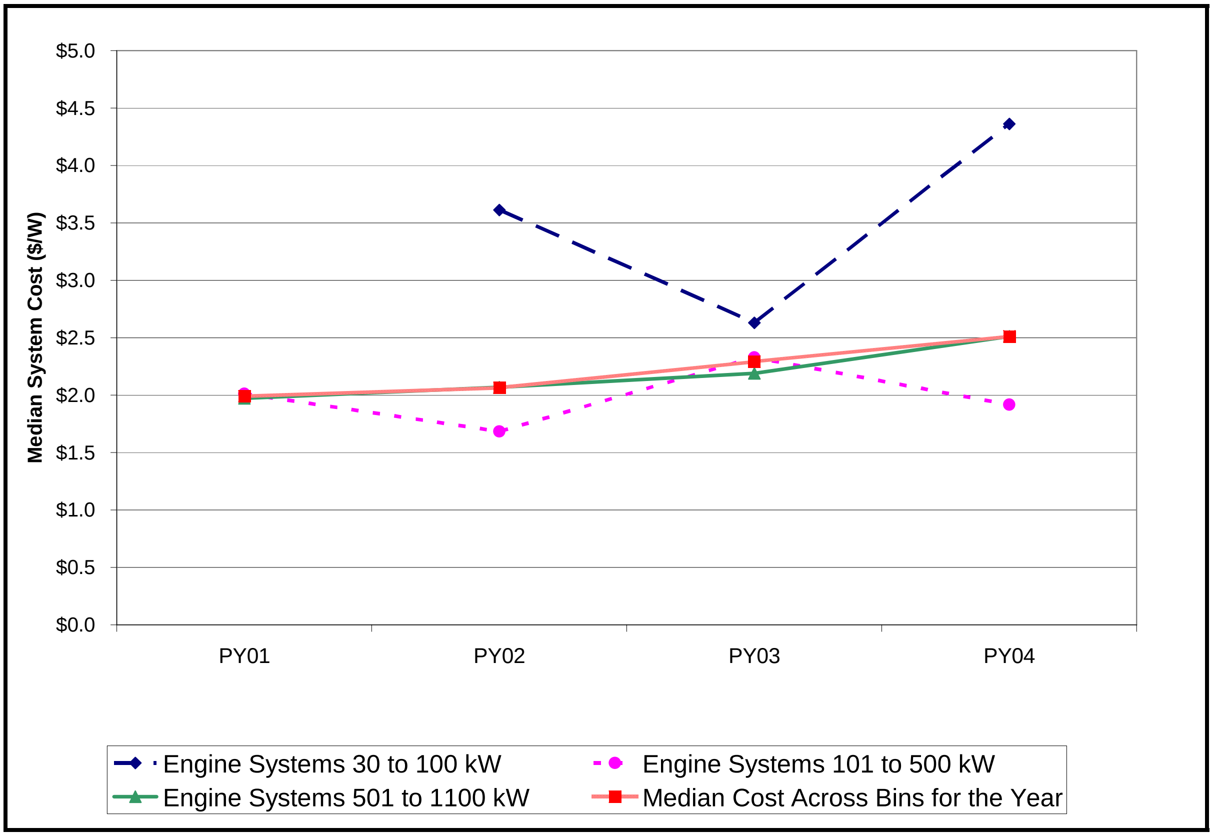
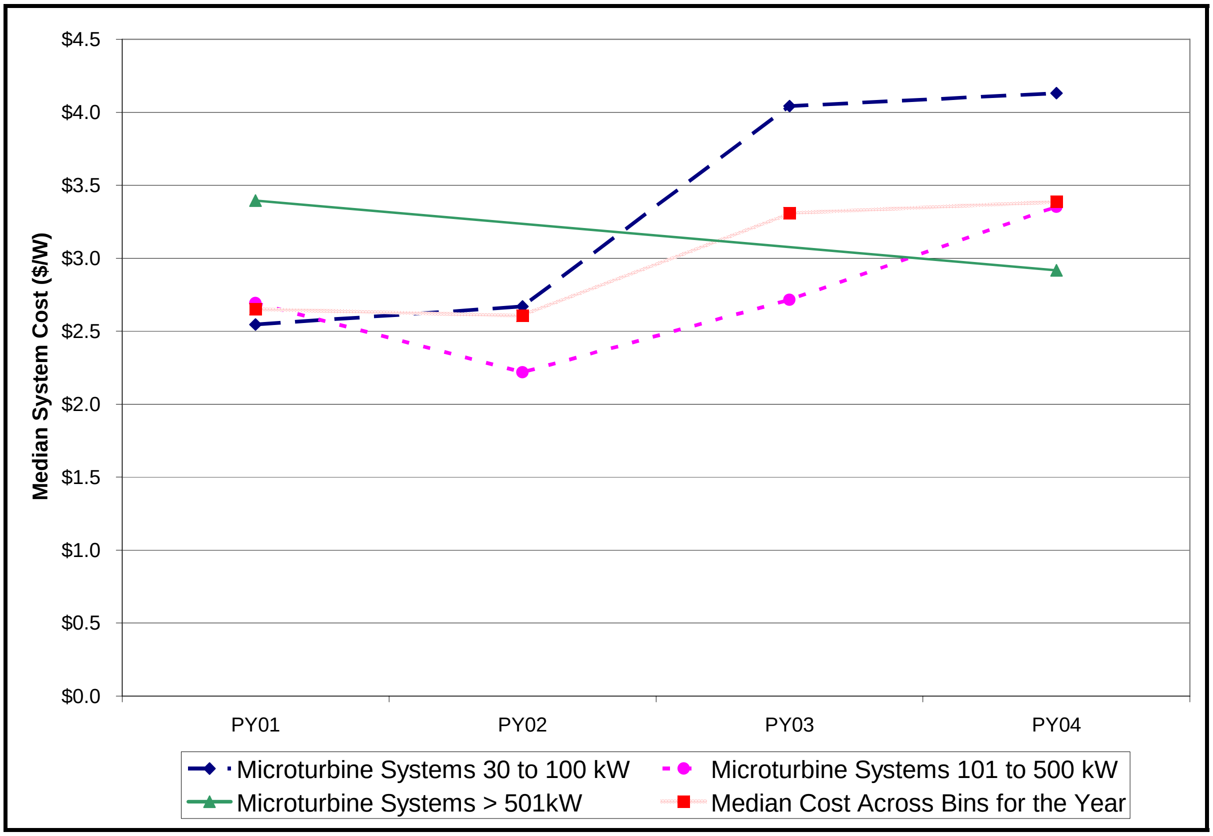


Figure 3-7 is a cost trend for natural gas-fired microturbines in the Complete project category. Generally, small to medium-sized microturbines demonstrated moderate increases in median costs from PY02 through PY04, with the costs of the 30 to 100 kW range rising more rapidly than the medium-sized microturbines.

For the 101 kW–500 kW systems, the median of project costs was relatively stable through PY01-PY03. The median of costs of smaller systems (≤ 100 kW) increased substantially during PY03; however, this median is based on a small number of projects and the variability exhibited by the cost data is large. The costs of the five projects ranged from \$2.17 to \$7.76 per Watt; the mean is \$4.22.

Figure 3-7: Cost Trend for Complete Natural Gas Microturbine Projects



Incentives Paid and Reserved

Incentives paid and reserved are presented in Table 3-7.[4] PV projects account for approximately 74 percent of the incentives paid for Complete projects, and 76 percent of the incentives reserved for Active projects.

New Level 3 projects entered the SGIP only through September 2002, at which time Level 3 was divided into Level 3-N and Level 3-R. Level 3 projects that were not Complete by the end of 2004 have been under development for more than two years. Some or all of these Active Level 3 projects may ultimately be withdrawn.

Table 3-7: Incentives Paid and Reserved

Incentive Level	Technology	Complete Incentives Paid			Active Incentives Reserved		
		Total (MW)	Avg. ($/W)	Total ($ MM)	Total (MW)	Avg. ($/W)	Total ($ MM)
1	PV	55.6	$3.67	$203.7	56.1	$3.77	$211.8
	Wind Turbine	1.6	$1.89	$3.1	0.6	$1.29	$0.8
	Fuel Cell	0.8	$4.50	$3.4	0.0	$0.00	$0.0
2	Fuel Cell	1.8	$2.48	$4.5	6.0	$2.27	$13.5
3	Engine	39.2	$0.58	$22.6	3.1	$0.75	$2.3
	Microturbine	4.2	$0.77	$3.2	0.0	$0.00	$0.0
	Gas Turbine	1.4	$0.59	$0.8	0.0	$0.00	$0.0
3-N	Engine	41.1	$0.58	$23.6	58.1	$0.53	$31.0
	Microturbine	6.2	$0.87	$5.4	7.3	$0.82	$5.9
	Gas Turbine	1.2	$0.83	$1.0	14.3	$0.21	$3.0
3-R	Engine	0.5	$1.12	$0.6	8.4	$0.83	$6.9
	Microturbine	1.7	$1.08	$1.8	2.2	$1.35	$3.0
Total	**Total**	**155.2**	**$1.76**	**$273.7**	**156.1**	**$1.78**	**$278.4**

[4] The maximum possible incentive payment for each system is the system size (up to 1,000 kW) multiplied by the applicable dollar per kW incentive rate.

Participants' Out-of-Pocket Costs After Incentive

Participants' out-of-pocket costs (total eligible project cost less the SGIP incentive) are summarized in Table 3-8. Cost information was provided by each of the PAs and is summarized here. Insights are, by definition, speculative and are based on a combination of assumed project costs, additional monies obtained from other incentive programs, and professional judgment. On a dollar-per-Watt ($/Watt) rated capacity-basis, Level 1 (renewable-fueled) fuel cells have the highest cost, followed by Level 1 PV. The higher first cost of Level 1 fuel cells is offset to some degree by their higher efficiency (reduced fuel purchases) and to a lesser degree by reduced air emission offsets. Higher costs for this technology likely include the cost of digester gas cleanup equipment. In certain instances, fuel cells also provide additional power reliability benefits that may drive project economics. PV is the next highest capital cost technology, followed by non-renewable-fueled fuel cells, renewable-fueled microturbines and non-renewable fueled microturbines, respectively.

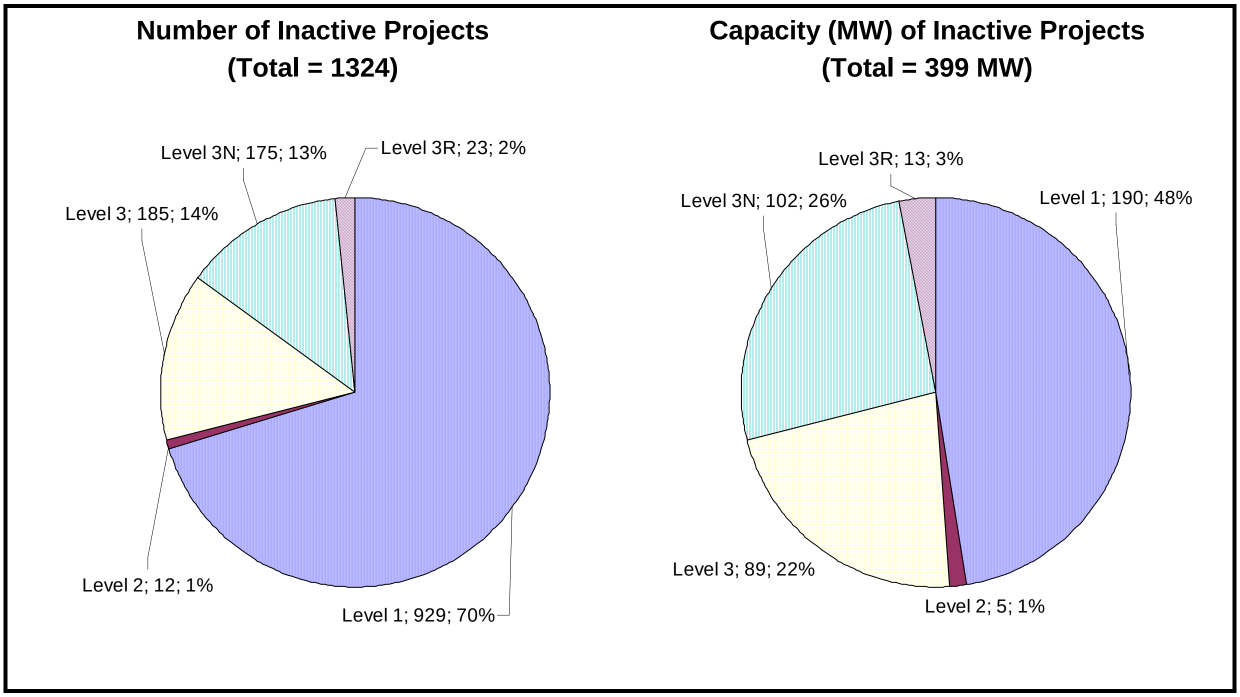
Table 3-8: SGIP Participants' Out-of-Pocket Costs after Incentive

Incentive Level	Technology	Complete			Active		
		Total (MW)	Avg. ($/W)	Total ($ MM)	Total (MW)	Avg. ($/W)	Total ($ MM)
1	PV	55.6	$4.58	$255	56.1	$4.86	$273
	Wind Turbine	1.6	$2.22	$4	0.6	$1.29	$1
	Fuel Cell	0.8	$5.20	$4	0.0	$0.00	$0
2	Fuel Cell	1.8	$5.86	$11	6.0	$4.39	$26
3	Engine	39.2	$1.52	$59	3.1	$1.90	$6
	Microturbine	4.2	$2.24	$9	0.0	$0.00	$0
	Gas Turbine	1.4	$2.11	$3	0.0	$0.00	$0
3-N	Engine	41.1	$1.61	$66	58.1	$1.83	$107
	Microturbine	6.2	$2.30	$14	7.3	$2.15	$16
	Gas Turbine	1.2	$3.05	$4	14.3	$1.88	$27
3-R	Engine	0.5	$1.67	$1	8.4	$1.77	$15
	Microturbine	1.7	$2.04	$3	2.2	$2.54	$6
Total	**Total**	**153.0**	**$2.83**	**$433**	**156.1**	$3.04	**$475**

3.4 Characteristics of Inactive Projects

As of December 31, 2005, there were 1,324 Inactive projects (those either withdrawn or rejected), representing 399 MW of generating capacity. Figure 3-8 presents the status of these Inactive projects.

Figure 3-8: Number and Capacity (MW) of Inactive Projects



It is interesting to note the following from Figure 3-8:

- Level 1 projects constitute the largest share of number of Inactive projects (929 or 70 percent) and the second largest share of total Inactive capacity (190 MW or 48 percent).
- Level 3/3-N projects account for the second largest share of number of Inactive projects (360 or 27 percent) and the largest share of total Inactive capacity (191 MW or 48 percent) due to the relatively larger average system size of Level 3/3-N compared to PV.
- The 23 Inactive Level 3-R projects account for 13 MW of total Inactive capacity (3 percent).
- The 12 Inactive Level 2 projects make up the smallest share of Inactive projects, representing only 5 MW of total Inactive capacity (1 percent).

4

SGIP Technologies Characterization

4.1 Introduction

A variety of DG technologies are eligible for application to the SGIP. Eligible technologies include solar photovoltaic systems; fossil and renewable fueled reciprocating engines, fuel cells, micro-turbines, small-scale gas turbines; and wind energy systems. This section provides information on typical configuration and performance characteristics of these technologies.

4.2 Solar Photovoltaic Systems

Photovoltaic cells (solar cells) are solid-state, semiconductor-based devices that convert radiant energy (light) directly into electricity. The passive qualities of photovoltaic (PV) systems provide PV technology with some attractive features in contrast with other power generation technologies. As long as an adequate source of light is provided, PV systems will quietly generate a steady electric current without emissions, fuel, or moving parts. These qualities have made PV technologies likely candidates for use in urban areas.

In urban areas flat-plate PV devices are generally installed on rooftops. Flat-plate collectors typically use large numbers of PV cells consolidated into modules, and then a group of modules are connected to form an array; all mounted on a rigid, flat surface. Flat-plate PV systems can be installed on rooftops to make up smaller-scale DG facilities.

PV cells consist of several layers of different materials. The primary layer is the semiconducting material where the photoelectric effect takes place, and is typically composed of silicon. PV systems are generally categorized by the type of material used as the semiconductor.

Today’s commercially available solar cells consist of five basic semiconductor materials, each with its own trade-offs between manufacturing costs and efficiency:

- Single-crystal, large-area planar silicon cells, which yield high efficiencies under normal light conditions.

- Single-crystal, small-area concentrator silicon cells, which yield higher efficiencies under concentrated light (from 20-1000 suns).
- Polycrystalline silicon cells, which are less expensive than single-crystal cells, but also less efficient.
- Thin film semiconductor materials, including amorphous silicon (a-Si), cadmium telluride (CdTe) and copper-indium-selenide (CIS). Amorphous silicon modules are a commercial product. They are less efficient than polycrystalline materials. The severe performance degradation that plagued early version of a-Si has been resolved, although they still suffer from an initial performance loss. CdTe also has stability and manufacturing challenges, in addition to public concern over the use of cadmium. CIS technologies have potentially high efficiencies, but face manufacturing throughput challenges.
- Multi-junction cells consisting of several layers of different semiconducting materials that are being produced primarily for space applications. These PV cells have achieved record-setting efficiencies as high as 34 percent under concentrated light, but are more complex to manufacture. Tandem-junction devices made of layers of amorphous silicon are currently available primarily for the terrestrial market.

Crystalline-silicon semiconductor-based systems dominate PV sales, accounting for over 84 percent of worldwide shipments.[1] Amorphous silicon thin-films account for another 11 percent of the market, and the rest is accounted for by small quantities of other thin-film products. Thin films may play a more significant role in the future, if they are able to reach cost and performance goals necessary to make the transition to large-scale, cost-effective manufacturing. A number of innovative non-conventional new technologies are also under research, including dye-sensitized solar cells, but they are not yet commercial.

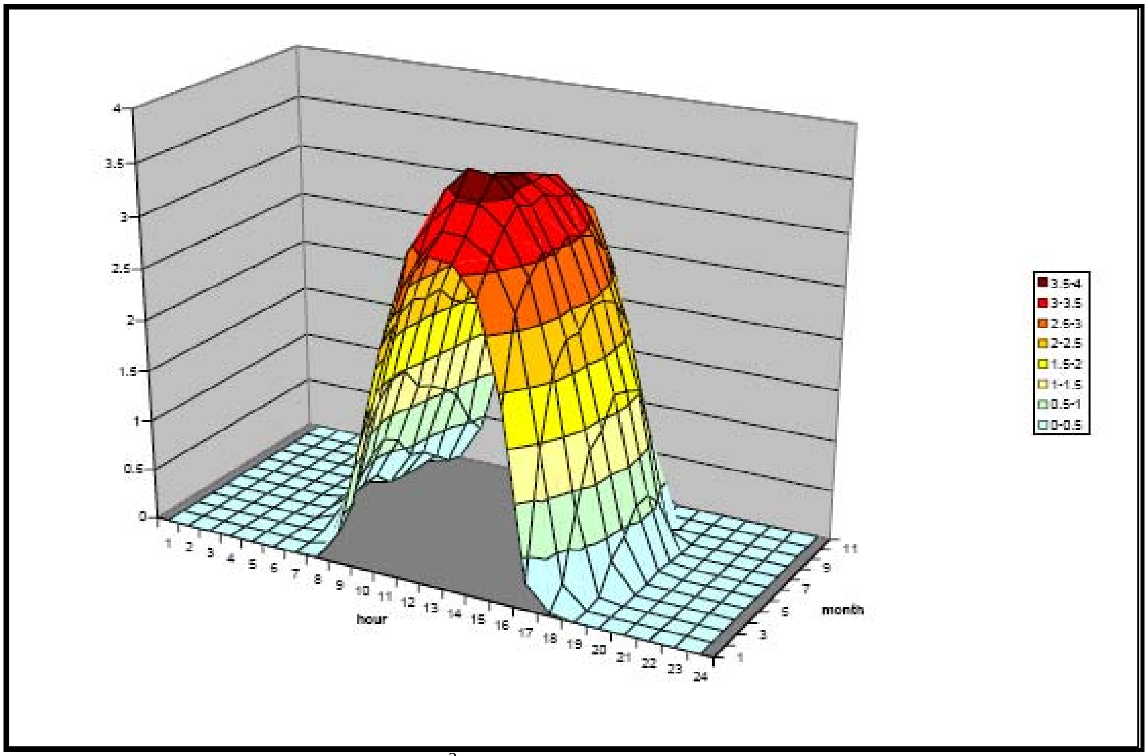
PV systems rely on solar radiation, an intermittent resource, to generate power. Unlike concentrating solar power (solar thermal) systems, PV modules make good use of diffuse sunlight and, therefore, are less sensitive to geographical variations in solar resource than concentrating solar power. Nonetheless, the intermittent nature of the solar resource means that electricity generation from PV systems change hourly as well as throughout the year. Similarly, even though PV systems can use diffuse sunlight, their performance is impacted by factors that reduce the amount of sunlight reaching the system (e.g., shading or soiling of PV panels). Lastly, PV performance is impacted by the orientation of the system and configuration (i.e., tilt).

Figure 4-1 represents a typical generation profile for a PV system. Electricity generation increases from early morning, generally peaks close to mid-day and then decreases as

[1] Paul Maycock, "PV News Annual Report of the PV Market," 2004

evening approaches. In addition, generation increases seasonally from spring to summer, and decreases across fall and through the winter.

Figure 4-1: PV Generation Output Profile



Source: California Energy Commission/E[3]

For DG applications, PV systems require an inverter to create alternating current. Typically, they will also require a mounting structure, which can range from flat roofing modules to shingles to mounting on frames at ground level. Most grid-connected systems do not use batteries, but if power reliability and backup power are important to the value of a system, then batteries, charge controllers, and more complex interconnection equipment will be required. This allows the PV system to continue operating while disconnected from the grid during power outages. These elements also add substantially to overall system costs.

High availability and no mechanical parts or variable costs make solar modules extremely reliable, contributing to their important role as back-up power in a variety of hybrid energy combinations and DG applications. Although availability of PV systems typically ranges near 99 percent, the cyclical quality of solar irradiance reduces the capacity factor to around 20 percent. Further, weathering degrades the efficiency over time, particularly for amorphous silicon, often reducing power output by around 20 percent of its initial output. Most modules sold today are advertised at their stabilized output rating.

Table 4-1 provides information on the typical module efficiencies, lifetime, and stability of different types of PV systems.

Table 4-1: Characteristics of PV Systems

Characteristic	a-Silicon	Polycrystalline Silicon	Single Crystalline Si	Cadmium Telluride (CdTe)	Copper Indium Selenide (CIS)
Module Eff.	6-8%	13-15%	14-16%	8-10%	9-11%
Lifetime	20 years	25 years	> 25 years	20 years	20 years
Stability[2]	10-20%	Stable	Stable	Stable	< 5%

Source: Navigant

4.3 Fuel Cells

Gas turbines, IC engines, and wind turbines represent systems that generate electricity by mechanical means (i.e., rotation of a stator). Fuel cells provide an electrochemical means of producing electricity. Like batteries, fuel cells generate electricity due to movement of positively charged ions (protons) and electrons in a solution (the electrolyte). The charged ions are created by passing reactants (oxygen and hydrogen) past catalyst-coated electrodes (an anode and cathode). Electrical current is created by preventing the migration of electrons through the electrolyte, and instead forcing electrons to pass only through an external circuit. The material making up the electrolyte generally determines the type of fuel cell. Unlike batteries, fuel cells require a constant stream of reactants to produce power on an on-going basis. In many instances, hydrogen to be used in a fuel cell is derived from hydrocarbon or alcohol fuels (e.g., methane, propane, methanol, etc.). A reformer is used to convert the feedstock fuel into a hydrocarbon-rich stream.

Fuel cells hold great promise of delivering high electrical conversion efficiencies with little or no emissions. Heat is typically recovered via a heat exchanger and is generally utilized for process heating at the site where the fuel cell is installed. For DG applications, fuel cell systems are commonly configured in combined heat and power arrangements. Their high efficiencies and reliability make them good candidates for providing baseload power. Moreover, fuel cell efficiencies increase at partial load, which provides increased operating flexibility and capability for load following. Because fuel cells produce direct current, power conditioning by electronic inverters are required for DG applications.

[2] Stability in terms of percentage loss in performance

Table 4-2 is a summary of typical operating characteristics, costs, efficiencies, and capacities of various types of fuel cells.

Table 4-2: Typical Fuel Cell Characteristics

Cost and Performance Characteristics	System 1	System 2	System 3	System 4	System 5	System 6
Fuel Cell Type	PAFC	PEM	PEM	MCFC	MCFC	SOFC
Nominal Electricity Capacity (kW)	200	10	200	250	2,000	100
Commercial Status 2002	Com'l	Demo	Demo	Demo	Demo	Demo
Operating Temperature (°F)	400	150	150	1,200	1,200	1,750
Package Cost (2002 $/kW)	3,850	4,700	2,950	4,350	2,400	2,850
Total Installed Cost (2002 $/kW)	4,500	5,500	3,600	5,000	2,800	3,500
O&M Costs ($/kW)	0.029	0.033	0.023	0.043	0.033	0.023
Electric Heat Rate (Btu/kWh)	9,480	11,370	9,750	7,930	7,420	7,580
Electrical Efficiency (% HHV)	36%	30%	35%	43%	46%	45%
Fuel Input (MMBtu/hr)	1.90	0.10	2.00	2.00	14.80	0.80
CHP Characteristics						
Heat Avail. > 160°F (MMBtu/hr)	0.37	0.00	0.00	0.22	1.89	0.10
Heat Avail. < 160°F (MMBtu/hr)	0.37	0.04	0.72	0.22	1.67	0.09
Heat Output (MMBtu/hr)	0.74	0.04	0.72	0.44	3.56	0.19
Heat Output (kW equivalent)	217	13	211	128	1,043	56
Total CHP Efficiency (%), HHV	75%	68%	72%	65%	70%	70%
Power/Heat Ratio	0.92	0.77	0.95	1.95	1.92	1.79
Net Heat Rate (Btu/kWh)	4,860	6,370	5,250	5,730	5,200	5,210
Effective Electrical Eff (%), HHV	70.3%	53.6%	65.0%	59.5%	65.7%	65.6%

Source: Energy Nexus Group

4.4 Microturbines

Microturbines are small combustion turbines generally the size of a refrigerator and have capacities below 300 kW. Their potential benefits include a small footprint, which allows them to be used where space is limited, light weight, low emissions, ability to use waste fuels, and high responsiveness. In typical configurations, microturbines are fueled by compressed natural gas, methane, or propane. This fuel is ignited in a controlled combustion process and the combustion gasses are forced through nozzles that act to turn a turbine at a very high rotation (e.g., over 40,000 rpm), thereby generating electricity. Waste heat is captured from the exhaust combustion gasses and typically transferred to a working fluid such as hot water for use in process or space heating.

Table 4-3 on the following page is a summary of microturbine characteristics for a variety of microturbines in the marketplace circa 2003.

Table 4-3: Typical Microturbine Characteristics

Characteristics	Company Marketing Literature, as of April 2003				Study by Onsite Energy Corporation (DOE), as of January 2000		Study by Arthur D Little (DOE), as of January 2000		
	Capstone	Elliott	Honeywell	Ingersoll-Rand	Year 2000	Year 2020	Year 2000	Year 2005	Year 2010
Size (kW)	30, 60	45, 60, 100, 200	Parallon 75	IR70, 250	100kW based on Parallon 75 model		25-300	25-300	25-1,000
Package costs ($/kW) (Total if applicable)	$925	--	--	$1,285	$800 ($1,970)	$350 ($915)	750-900	500-700	400-600
Electrical efficiency LHV (%)	28% (±2)	29.5%	27.5%	28%	28.4%	39.8%	30%	33-36%	38-42%
Heat Rate LHV (Btu/kWh)	12,200	11,600	12,400	12,200	12,000	8,557	--	--	--
Exhaust gas temperature	305 C	274 C	--	--	--	--	--	--	--
Total exhaust energy (Btu/hr)	541,000	543,000	338,000	100,000-400,000	449,800	274,800	--	--	--
NOx (ppm)	<9 ppm	< 20 ppm	< 50 ppm	< 9 ppm	< 10 ppm	2-3 ppm	9-25 ppm	--	< 9 ppm
SOx	--	--	--	--	--	--	Negligible	--	Negligible
PM	--	--	--	--	--	--	Negligible	--	Negligible
Life (hours)	50,000	--	--	80,000	--	--	--	--	--

Source: Critical Infrastructure Modeling and Assessment Program, "Workshop on Combined Heat and Power Development in Virginia," May 30, 2003 (www.cimap.vt.edu/workshop/03/APPENDIX-C.pdf)

4.5 Internal Combustion Engines

Reciprocating internal combustion (IC) engines have been a preferred means of electricity generation over the past hundred years. Power is produced when a mixture of air and fuel is ignited, causing expansion of pistons, which in turn are connected to a crankshaft that turns a generator. IC engines typically range in capacity from a few kilowatts to over 5 megawatts. While IC engines can consist of diesel or spark ignited systems, only spark ignited engines are used in the SGIP. Spark ignition engines are predominately fueled with natural gas, but can be fired using propane, gasoline, and waste fuels such as landfill gas. Currently, IC engines are more commonly being used for combined heat and power (CHP) applications due to their rapid start up and good load following capabilities. Waste heat can be recovered from the engine exhaust and engine cooling systems to produce either hot water or low pressure steam. Table 4-4 is a summary of performance and operating characteristics for IC engines.

Table 4-4: Typical Internal Combustion Engine Characteristics

Cost and Performance Characteristics	System 1	System 2	System 3	System 4	System 5
Baseload Electric Capacity (kW)	100	300	800	3,000	5,000
Total Installed Cost (YR 2001 $/kW)	$1,515	$1,200	$1,000	$920	$920
Electric Heat Rate (Btu/kWh), HHV	11,147	10,967	10,246	9,492	8,758
Electrical Efficiency (%), HHV	30.6%	31.1%	33.3%	36.0%	39.0%
Engine Speed (rpm)	1,800	1,800	1,200	900	720
Fuel Input (MMBtu/hr)	1.11	3.29	8.20	28.48	43.79
Required Fuel Gas Pressure (psig)	<3	<3	<3	43	65
CHP Characteristics					
Exhaust Flow (1000 lb/hr)	1.0	3.3	10.9	48.4	67.1
Exhaust Temperature (Fahrenheit)	1,060	1,067	869	688	698
Heat Recovered from Exhaust (MMBtu/hr)	0.20	0.82	2.12	5.54	7.16
Heat Recovered from Cooling Jacket (MMBtu/hr)	0.37	0.69	1.09	4.37	6.28
Heat Recovered from Lube System (MMBtu/hr)	0	0	0.29	1.22	1.94
Total Heat Recovered (MMBtu/hr)	0.57	1.51	3.50	11.12	15.38
Total Heat Recovered (kW)	167	443	1,025	3,259	4,508
Form of Recovered Heat	Hot H_2O	Hot H_2O	Hot H_2O	Hot H_2O	Hot H_2O
Total Efficiency (%)	81%	77%	76%	75%	74%
Thermal Output/Fuel Input (%)	51%	46%	43%	39%	35%
Power/Heat Ratio	0.60	0.68	0.78	0.92	1.11
Net Heat Rate (Btu/kWh)	4,063	4,687	4,774	4,857	4,914
Effective Electrical Efficiency	0.84	0.73	0.71	0.70	0.69

Source: EEA

4.6 Small Gas Turbines

Small gas turbines are combustion turbines that typically range in size from 500 kW to 5 MW. They can be used for dedicated power production, but are also used in combined heat and power (CHP) applications. Because of their high turbine exhaust temperatures, small gas turbines have excellent capability for producing high quality process steam for industrial and some commercial purposes. Fuels for small gas turbines can include fossil based fuels (i.e., natural gas, propane) and renewable fuels such as landfill or digester gas. Special design approaches for small gas turbines are resulting in very low NOx emissions, making them good candidates for application in areas facing air quality constraints. Table 4-5 provides representative performance and operating characteristics of small gas turbines.

Table 4-5: Typical Small Gas Turbine Characteristics

Electricity Capacity	1 MW	5 MW
Cost and Performance Characteristics		
Total Installed Cost (2000 $/kW)	$1,780	$1,010
Electric Heat Rate (Btu/kWh), HHV	15,580	12,590
Electrical Efficiency (%), HHV	21.9%	27.1%
Fuel Input (MMBtu/hr)	15.6	62.9
Required Fuel Gas Pressure (psig)	95	160
CHP Characteristics		
Exhaust Flow (1,000 lb/hr)	44	162
GT Exhaust Temperature (Fahrenheit)	950	950
HRSG Exhaust Temperature (Fahrenheit)	280	280
Steam Output (MMBtu/hr)	7.1	26.6
Steam Output (1,000 lbs/hr)	6.7	25.0
Steam Output (kW equivalent)	2,080	7,800
Total CHP Efficiency (%), HHV	68%	69%
Power/Heat Ratio	0.48	0.64
Net Heat Rate (Btu/kWh)	6,673	5,947
Effective Electrical Efficiency (%), HHV	51	57

Source: Energy Nexus Group

5

Program-Level Impacts and Requirements

5.1 Introduction

This section presents system impacts at the program-level from SGIP projects that were on-line through the end of PY05. Impacts examined include affects on energy delivery; peak demand; waste heat utilization and efficiency requirements; renewable fuel use requirements; and greenhouse gas emission reductions. Impacts of all combined SGIP technologies are examined at the program-wide level and, where appropriate, at the PA-specific level.

Impacts were estimated for all on-line projects regardless of their stage of advancement in the program, so long as they began normal generation operations prior to December 31, 2005. On-line projects include projects for which SGIP incentives had already been disbursed (Complete projects), as well as projects that had yet to complete the SGIP process (Active projects). This is the same assumption used in prior year impact evaluations. Not all projects for which impacts were determined were equipped with monitoring equipment. Similarly, some monitoring data had not been received from third party data providers. Consequently, this annual impact evaluation relies on a combination of metered data, statistical methods, and engineering assumptions. Data availability and corresponding analytic methodologies vary by program level and technology.

5.2 Overall Program Impacts

Energy and Demand Impacts

Electrical energy and demand impacts were calculated for Complete and Active projects that began normal operations prior to December 31, 2005. Impacts were estimated using year 2005 available metered data and other system characteristics information from the program tracking systems maintained by the PAs and augmented with information obtained over time by Itron.

By the end of 2005, 784 SGIP facilities were on-line representing over 190 MW of electricity generating capacity. Some of these facilities (e.g., PV and wind) provided their host sites with only electricity, while cogeneration facilities provided both electricity and thermal energy (i.e., heating or cooling). Table 5-1 provides information on the amount of electricity delivered by SGIP facilities throughout calendar year 2005. Energy delivery from Program

Level 1 and 2 projects are divided by system type, while energy delivery for all Level 3 projects is combined across system types. Both actual metered energy and estimated energy figures are provided.

Table 5-1: Statewide Energy Impact in 2005 by Quarter (MWh)

	Q1-2005	Q2-2005	Q3-2005	Q4-2005	Total
	MWh	MWh	MWh	MWh	MWh
Level 1 PV	**8,844**	**20,068**	**23,447**	**13,556**	**65,915**
Metered	4,800	10,837	11,918	6,786	34,340
Estimated	4,044	9,231	11,529	6,771	31,575
Level 1 Wind	**301**	**703**	**634**	**400**	**2,038**
Metered	291	403	366	230	1,290
Estimated	10	300	269	169	748
Level 1 Fuel Cell	**632**	**923**	**401**	**682**	**2,637**
Metered	632	922	401	678	2,634
Estimated	0	0	0	3	3
Level 2 Fuel Cell	**1,686**	**1,989**	**3,884**	**3,606**	**11,164**
Metered	421	396	360	613	1,790
Estimated	1,265	1,593	3,524	2,993	9,374
Level 3/3N/3R	**92,375**	**105,442**	**104,079**	**97,600**	**399,495**
Metered	35,613	44,748	57,023	51,472	188,856
Estimated	56,761	60,694	47,055	46,128	210,639
Total	**103,837**	**129,124**	**132,445**	**115,844**	**481,250**

Level 3/3N/3R engines and turbines made the largest contribution to SGIP energy delivery, providing 83 percent of the annual energy delivery total. Level 1 PV projects provided the second largest contribution to energy delivery, providing about 14 percent of the total. Due to the limited number of wind and fuel cell projects installed in the SGIP by PY05, these projects had small contributions to 2005 energy delivery.

To put the SGIP electricity numbers in context, the overall 2005 demand for electricity in California was approximately 250,000 GigaWatt-hours (GWhrs).[1] Consequently, SGIP facilities supplied a little less than 0.2 percent of the electricity consumed by Californians in 2005. This appears to be a reasonable percentage of overall energy delivery given the size of California's electricity demand.

[1] This represents an estimate of the 2005 demand taken from "California Energy Demand 2006-2016 Staff Energy Demand Forecast," June 2005, CEC-400-2005-034-SD

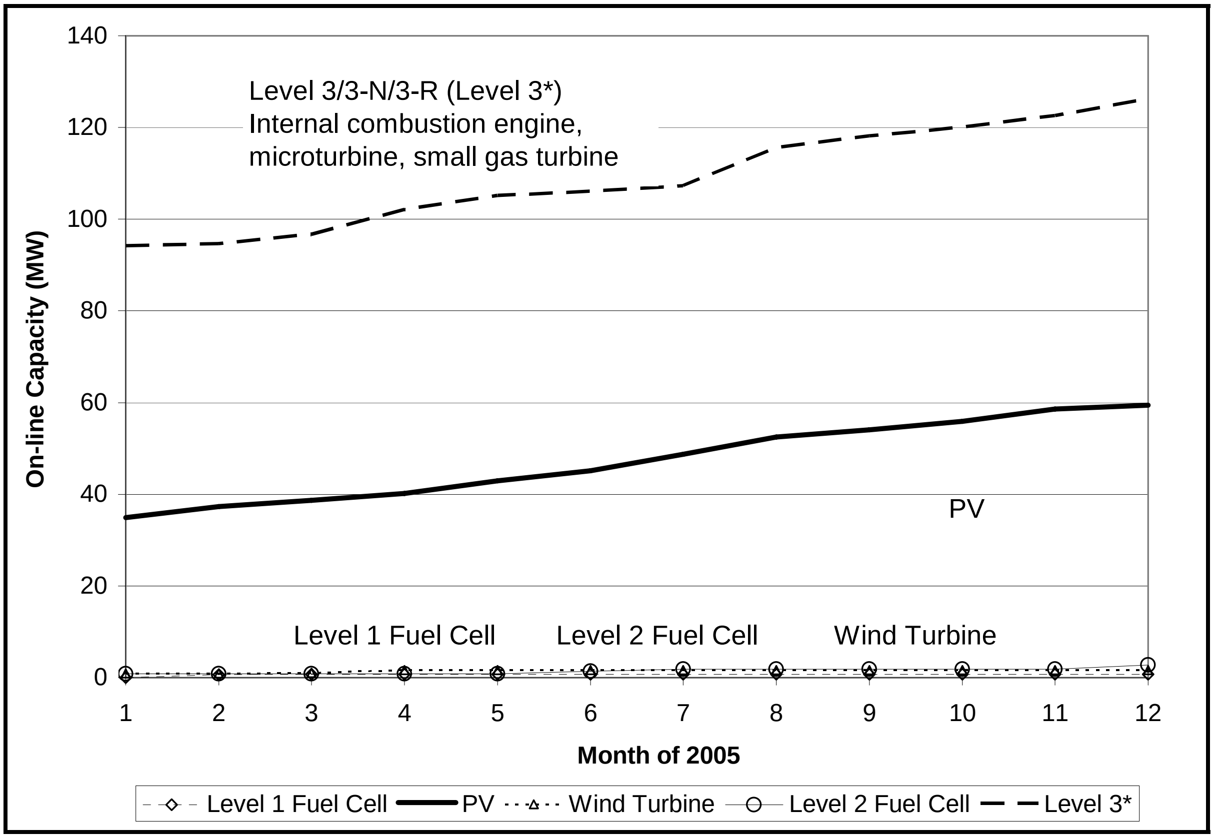
Another way to look at energy demand impact by the SGIP is to examine energy impacts at the PA-specific level. Table 5-2 provides energy impact estimates for SGIP technologies deployed within each PA service territory.

Table 5-2: Energy Impact in 2005 by PA (MWh)

	PG&E	SCE	SCG	SDREO	Total
	MWh	MWh	MWh	MWh	MWh
Level 1 PV	**34,137**	**11,707**	**10,664**	**9,408**	**65,915**
Metered	18,303	2,954	4,494	8,588	34,340
Estimated	15,834	8,753	6,170	819	31,575
Level 1 Wind		**2,038**			**2,038**
Metered		1,290			1,290
Estimated		748			748
Level 1 Fuel Cell		**2,637**			**2,637**
Metered		2,634			2,634
Estimated		3			3
Level 2 Fuel Cell	**10,551**			**613**	**11,164**
Metered	1,177			613	1,790
Estimated	9,374			0	9,374
Level 3/3N/3R	**131,330**	**63,086**	**179,778**	**25,301**	**399,495**
Metered	56,884	23,441	83,242	25,289	188,856
Estimated	74,447	39,645	96,536	12	210,639
Total	**176,018**	**79,469**	**190,442**	**35,321**	**481,250**

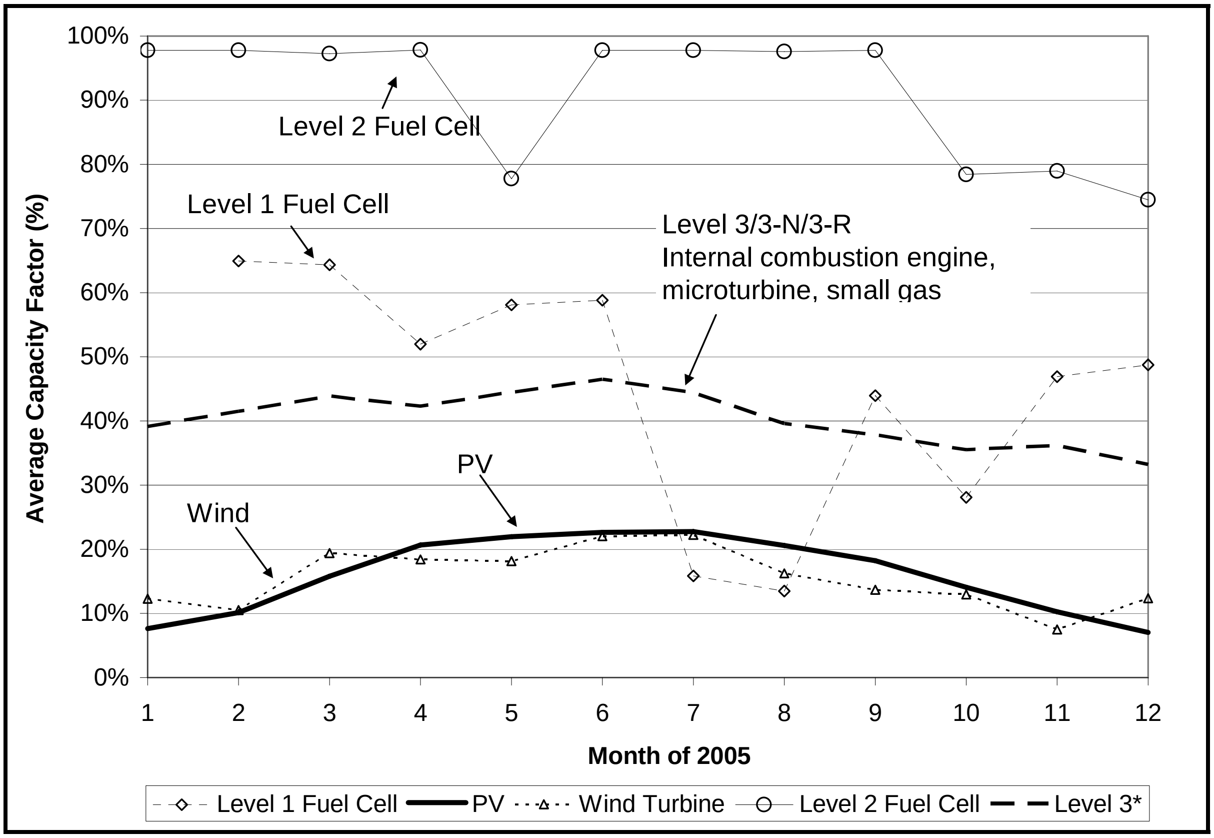
An important aspect of electrical energy impact is the time of delivery. For example, energy delivery made in summer may be more important than energy delivery made in winter. Figure 5-1 depicts growth in on-line capacity of SGIP technologies (grouped by incentive level) by month through 2005. This figure does not show the actual energy delivered in each month, but instead reflects the generating capacity potentially available for electricity production. Engines and turbines (Level 3/3-N/3-R projects) provided the greatest on-line capacity contributions during PY05, followed by Level 1 PV projects. As with quarterly energy delivery, the limited number of fuel cell and wind projects deployed in the SGIP in 2005 is reflected in their low on-line capacities.

Figure 5-1: On-Line Capacity by Month (2005)



Typically, capacity factor represents the percentage of the rebated capacity that is actually generating at any point in time. Capacity factors for SGIP projects were developed by comparing actual generation against rebated capacity. Figure 5-2 shows capacity factors for SGIP technologies (grouped by incentive level) by month through 2005. Level 2 fuel cells generally had excellent operating performance in terms of capacity factor. They had capacity factors of over 90 percent through most of 2005, with some decreases in the mid and latter portions of the year. However, there were few fuel cells operating in the SGIP in 2005, and the decrease in capacity factor may not be representative. Similarly, although low capacity factors for Level 1 fuel cells may reflect operational issues associated with renewable fuels, there were too few systems for the results to be representative. Level 3/3-N/3-R projects demonstrated relatively flat overall capacity factors, generally staying between 35 to 50 percent. Level 1 PV projects had capacity factors that ranged from approximately 12 percent to slightly over 20 percent.

Figure 5-2: Average Capacity Factor by Month (2005)



Peak Demand Impact

The ability of SGIP projects to supply electricity during times of peak demand represents a critical impact. Table 5-3 summarizes the overall SGIP program impact on electricity demand coincident with the 2005 CAISO system peak load. In 2005, the CAISO system peak reached a maximum value of 45,380 MW on July 20 during the hour from 3:00 to 4:00 p.m. (PDT). There were 659 SGIP projects known to be on-line when the CAISO experienced this summer peak, but generator electric interval-metered data were available for only 280 of them. While the total capacity of these operational projects exceeded 160 MW, the total impact of the SGIP projects coincident with the CAISO peak load is estimated at slightly below 93 MW. Level 3/3-N/3-R engines and turbines accounted for 73 percent of the 2005 peak demand impact; and Level 1 PV systems accounted for 24 percent.

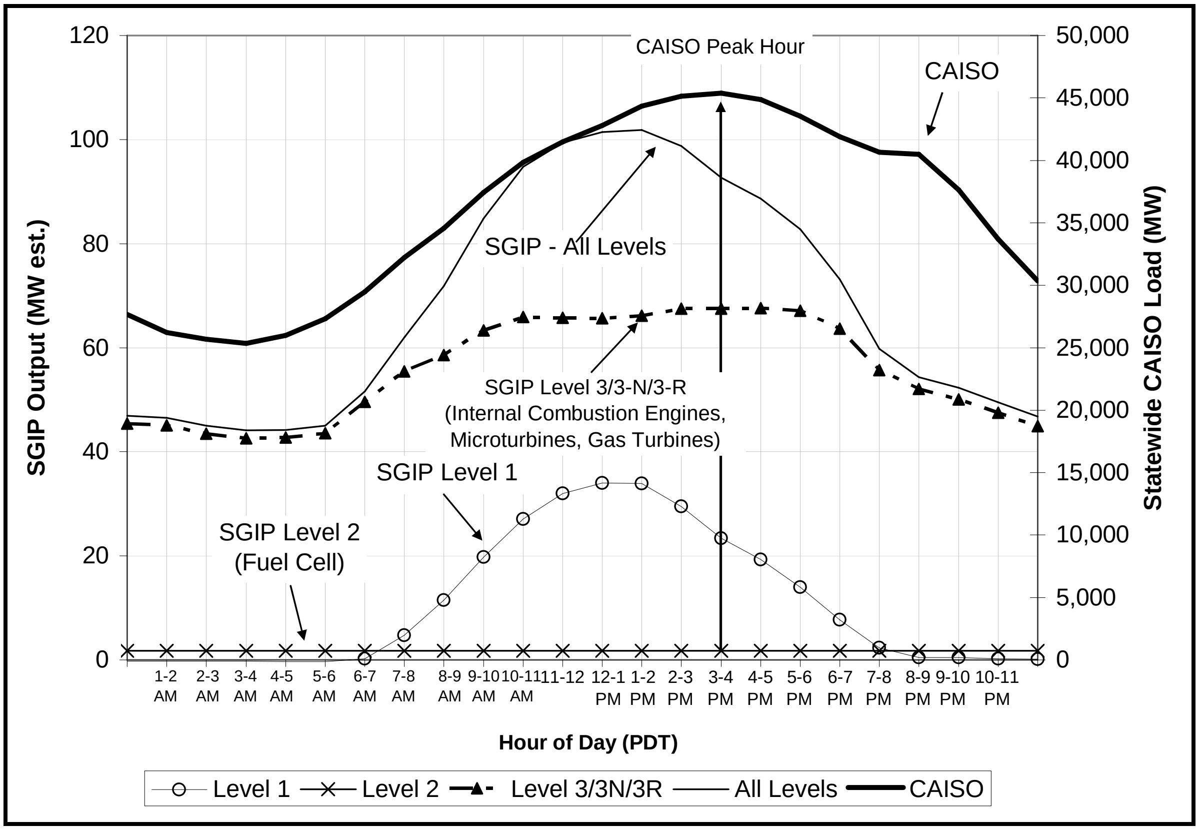
Table 5-3: Demand Impact Coincident with 2005 CAISO System Peak Load

Level / Basis	On-Line Systems (n)	On-Line Capacity (kW)	Peak Demand Impact (kW_P)
Level 1 PV	**435**	**49,602**	**22,556**
Metered	174	24,022	11,077
Estimated	261	25,580	11,479
Level 1 Wind	**2**	**1,649**	**906**
Metered	1	950	651
Estimated	1	699	255
Level 1 Fuel Cell[2]	**2**	**750**	**-54**
Metered	2	750	-54
Estimated	0	0	0
Level 2 Fuel Cell	**3**	**1,800**	**1,762**
Metered	1	200	196
Estimated	2	1,600	1,566
Level 3/3N/3R	**217**	**106,721**	**67,536**
Metered	102	49,685	33,297
Estimated	115	57,036	34,240
Total	**659**	**160,522**	**92,707**

[2] The negative peak demand impact seen for the Level 1 fuel cells represents an unusual situation where the fuel cells were down and there were parasitic loads associated with the systems.

Figure 5-3 graphically depicts the manner in which SGIP technologies on-line during 2005 impacted the CAISO 2005 system peak. Level 1 projects (which are dominated by PV on a capacity basis during 2005) demonstrate a generation profile that declines prior to the CAISO peak at 3 to 4 p.m. This is not unexpected given that nearly all PV systems have a southern exposure that will result in peak generation close to noon during July. Similarly, Level 3/3-N/3-R could be expected to demonstrate a generation somewhat closer to the CAISO demand curve as this would result in the greatest peak demand savings to the SGIP host site. The combined set of SGIP facilities demonstrates a slight leading generation profile to the CAISO peak, but is generally responsive to the CAISO demand curve and the peak.

Figure 5-3: Hourly Profiles by Incentive Level on CAISO Peak Day



Efficiency and Waste Heat Utilization Requirements

Cogeneration facilities represent a significant portion of the on-line generating capacity of the SGIP. To ensure that these facilities harness waste heat and realize high overall system and electricity efficiencies, Public Utility Code (PUC) 218.5 requires that participating Level 2 and Level 3/3-N technologies face certain minimum levels of thermal energy utilization and overall system efficiency.

PUC 218.5(a) requires that recovered useful waste heat from a cogeneration system exceeds five percent of the combined recovered waste heat plus the electrical energy output of the system. PUC 218.5(b) requires that the sum of the electric generation and half of the heat recovery of the system exceeds 42.5% of the energy entering the system as fuel. A summary of these requirements is presented in Table 5-4.

Table 5-4: Program Required PUC 218.5 Minimum Performance

Element	Definition	Minimum Requirement
218.5 (a)	Proportion of facilities' total annual energy output in the form of useful heat	5.0%
218.5 (b)	Overall system efficiency (50% credit for useful heat)	42.5%

Review of Useful Thermal Energy and System Efficiency

By the end of 2005, there were 262 Level 2/3/3-N/3-R cogeneration systems online. Table 3-2 in Section 3 provides a detailed summary of online systems by Incentive Level, Technology, and Fuel Type.

Metered electricity, heat and fuel data were used to determine Level 2 and Level 3/3-N compliance with the useful waste heat recovery requirements (by level and technology). There were 74 sites in all for which HEAT data were available for this analysis, as detailed in Table 5-5.

Table 5-5: Level 2/3/3-N Useful Thermal Energy Data Availability (CY05)

Level	Technology	PGE	SCE	SCG	SDREO	Total
2	**FC**	1	--	--	1	2
3	**GT**	1	--	--	--	1
3	**ICE**	11	2	5	10	28
3	**MT**	1	--	--	8	9
3N	**ICE**	3	4	13	7	27
3N	**MT**	3	--	4	--	7
Total		**20**	**6**	**22**	**26**	**74**

There were various combinations of data available to estimate performance metrics. For example, some sites have ENGO and HEAT metering but lack FUEL data. Alternatively, some sites have ENGO and FUEL metering but lack HEAT data. Adding to the complexity of the analysis, within the metered data for a site there are many instances of unavailable data from one or more data sources. To simplify the presentation of results, thermal efficiency results are presented for metered data only. In previous studies the sample of metered sites and the population of completed sites were not large enough to justify sophisticated sampling and expansion techniques. As the SGIP matures, future studies may expand this analysis to include estimated data based on averages for similar sites.

SGIP facilities use a variety of means to recover heat for useful purposes, and to apply that heat to provide various forms of heating and cooling services. The end-uses served by recovered useful thermal energy are summarized in Table 5-6, which includes all projects that had come on-line through December 2005.

Table 5-6: End-Uses Served by Level 2/3/3-N Recovered Useful Thermal Energy (Total n and kW as of 12/31/2005)

End Use Application	On-Line Systems (n)	On-Line Capacity (kW)
Heating Only	157	69,546
Heating & Cooling	54	33,771
Cooling Only	25	19,253
To Be Determined	10	5,407
Total	236	122,570

Useful heat recovery was monitored to assess actual heat recovery and system efficiency performance. Availability of useful waste heat information for 2005 is summarized in Table 5-6, which provides the number and capacities of cogeneration projects for which useful thermal energy data for CY05 were available. In some cases, availability of CY05 data was not sufficient to estimate PUC 218.5 thermal energy proportions or efficiencies due to their annual basis. By the end of calendar year 2005, data for eighty sites were obtained, as shown in Table 5-7. After filtering this data for sufficient quantity of data, six sites were excluded from the analysis bringing the final number of sites used in the analysis to seventy four.

Table 5-7: Data Available by End-Uses Served for Level 2/3/3-N Recovered Useful Thermal Energy (Total n and kW as of 12/31/2005)

End Use	On-Line Systems (n)	On-Line Capacity (kW)
Heating Only	45	20,532
Heating & Cooling	25	13,829
Cooling Only	10	7,413
Total	**80**	**41,774**

Overall Cogeneration System Efficiency Actually Observed

Available metered thermal data collected from on-line cogeneration projects were used to calculate overall system efficiency by incorporating both the electricity produced as well as the useful heat recovered. Results are summarized in Table 5-8. Six of the sites for which heat recovery information was available in Table 5-7 were excluded due to the limited quantity of validated metered data available, bringing the number of sites for which metered data is available down to 74.

Table 5-8: Level 2/3/3-N Cogeneration System Efficiencies (n=74)

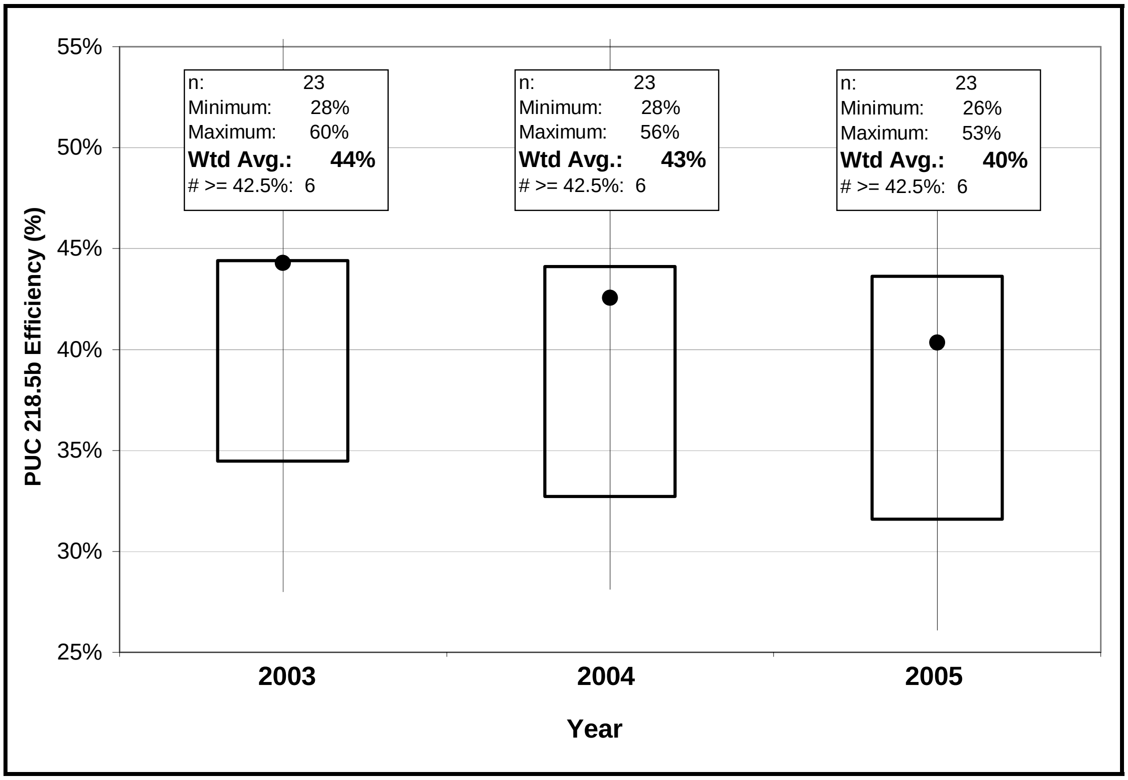
Summary Statistic	218.5 (a) proportion	218.5 (b) Efficiency	Overall Plant Efficiency
Min	1%	8%	11%
Max	72%	54%	72%
Median	45%	39%	51%
Mean	46%	41%	53%
Std Dev	12%	8%	11%
Coefficient of Variation	0.3	0.2	0.2

At least 10 months of operating data were available for 44 of the 74 systems. In 17 other cases at least six months of data were available for either the first half or the second half of 2005. Because the basis of the PUC 218.5 proportions and efficiencies are annual, when at least six months of data from several seasons are available, the calculated results were annualized and thus were considered representative of what could be expected on an annual basis.

Metered data collected to date suggest that roughly one out of every three Level 2/3/3-N projects achieved the 218.5 (b) overall system efficiency target of 42.5%. The limited quantities of cogeneration system data available for this impact analysis suggest the possibility that actual system efficiencies are systematically lower than planned system efficiencies. However, collection and analysis of additional data is required before definitive conclusions can be drawn. Data were available for two fuel cell projects, both of which satisfied the requirements of PUC 218.5 (a) and PUC 218.5 (b) system efficiency.

Cogeneration system PUC 218.5 (b) system efficiency data from 2003 through 2005 are available for 23 of the 74 projects. For these systems a comparison of efficiencies from 2003 through 2005 is depicted graphically in Figure 5-4. These data indicate a slight downward trend in PUC 218.5 (b) system efficiencies. The boxes in Figure 5-4 represent the range from the 25th quartile to the 75th quartile. The bold dot for each calendar year represents the weighted average PUC 218.5(b) efficiency (weighted by system size). This figure graphically displays two important messages. First, it suggests that larger cogeneration systems tend to operate at a higher PUC 218.5(b) efficiency level than smaller cogeneration systems. Second, it suggests that over time the PUC 218.5(b) efficiency degrades slightly.

Figure 5-4: Level 2/3/3-N Cogeneration System PUC 218.5 (b) Trend



<u>Electrical Conversion Efficiency Actually Observed</u>

Results of an analysis of cogeneration system electrical conversion efficiencies are presented in Table 5-9. ENGO and FUEL usage data were combined to develop a calculation of electric conversion efficiency. In the case of reciprocating engines (ICE), actual electrical conversion efficiencies of approximately 29% are typical for monitored SGIP cogeneration systems. This typical result is below electrical conversion efficiencies normally found in published technical specifications of engine-generator set manufacturers. These nominal nameplate electrical generating efficiencies published by manufacturers generally exceed 30%, and sometimes exceed 35%.

Table 5-9: Level 2/3/3-N Electrical Conversion Efficiency[3]

Summary Statistic	Fuel Cells (FC)	Internal Combustion Engines (ICE)	Microturbines (MT)
n	2	55	16
Min	41%	19%	6%
Max	43%	37%	29%
Median	42%	29%	22%
Mean	42%	29%	21%
Std Dev	2%	3%	5%

Observed electrical efficiencies for fuel cells were higher than reciprocating engines, and electrical efficiencies for reciprocating engines were higher than microturbines, as expected. The median efficiency actually observed for microturbines was 22%. This is slightly lower than the median 23% observed in 2004 and the nominal microturbine efficiencies typically published by manufacturers (approximately 29%). For purposes of comparison, the observed electrical conversion efficiencies are presented in Table 5-10 with representative nominal efficiencies. In the context of PUC 218.5 (b) efficiency calculations, these variances are relatively more significant than those on the useful recovered heat side of the equation because only 50% credit is given to the recovered heat in the 218.5 (b) efficiency equation. These factors are discussed in more detail in the following section.

Table 5-10: Representative Nominal Versus Observed Gross Electrical Conversion Efficiencies

Combustion Technology	Representative Nominal Efficiency (%, LHV)	Median Observed Efficiency (%, LHV)
Fuel Cell (FC)	39%	42%
Internal Combustion Engine (ICE)	34%	29%
Microturbine (MT)	29%	22%

Source: FC: Energy Nexus Group; ICE: EEA; MT: Critical Infrastructure Modeling and Assessment Program, "Workshop on Combined Heat and Power Development in Virginia," May 30, 2003 (www.cimap.vt.edu/workshop/03/APPENDIX-C.pdf)

[3] The electrical conversion efficiencies are calculated as the ratio of gross electric generator output to *lower heating value* of fuel content after converting both components to an identical unit basis. Utility companies refer to natural gas energy content in terms of higher heating value (HHV), which includes the heat that could be recovered if products of combustion were allowed to condense. Engine manufacturers refer to natural gas energy content in terms of lower heating value (LHV), which is based on products of combustion remaining in a gaseous or vapor state.

Useful Heat Recovery Actually Observed

To enable direct comparison of systems of different sizes the monthly average heat recovery raw data were normalized with respect to net generator electric energy output. Normalized actual useful heat recovery rates are therefore expressed in terms of thousand Btus (kBtu) of useful recovered heat per kWh of net generator electric energy production. The recovered useful thermal energy data for Level 3/3-N cogeneration systems are summarized in Table 5-11. For the 74 systems where 2005 data were available for this analysis, substantial variability among systems was observed in the normalized measure of monthly average heat recovery rate. This variability is reflected in the incidence of several projects with very minimal heat recovery, as well as the considerable variability (i.e., 2 to 5 kBtu/kWh) observed for the projects where appreciable quantities of useful heat were recovered.

Table 5-11: Actual Useful Heat Recovery Rates (n = 74)

Summary Statistic	Metered	Value (kBtu/kWh)
Min		0.03
Max		8.9
Median		2.9
Mean		3.1
Std Dev		1.5
CV		0.5

In general, the actual useful heat recovery rates observed in 2005 were less than projected by engineering calculations completed during the design stage of cogeneration system project development. A more detailed analysis of the causal factors was conducted which revealed systematic issues with cogeneration system performance[4]. In that analysis, it was discovered that lower than expected results are due to numerous factors, including: design problems, operational problems, unanticipated operating conditions, and system or component reliability problems.

Finally, it must be emphasized that although the quantity of useful recovered heat data is significant, it is not comprehensive. While the total capacity of operational cogeneration systems was approximately 125 MW at the end of 2005, this analysis included useful recovered heat data for projects totaling just over 40 MW. In addition, for some of these projects less than a complete year's worth of data were available. This monitored group does not represent a statistical sample; rather, it could best be characterized as a monitored group of cogeneration systems for which useful recovered heat data were available. Nonetheless, given the consistent nature of the monitored data over the past several years, the results

[4] Itron, "CPUC Self-Generation Incentive Program: In-Depth Analysis of Useful Waste Heat Recovery and Performance of Level 3/3N Systems," August 2006.

strongly suggest there are real and systematic differences between planned system efficiency and actual system efficiency.

Renewable Fuel Use Requirements

Within the context of the SGIP, renewable fuel use facilities are those cogeneration facilities that use biogas as an energy resource. Biogas refers to a methane rich gas that is created by anaerobic digestion of organic materials. Common sources of biogas include landfill gas projects, waste water treatment facilities and dairies using anaerobic digesters as a means of manure management.

Restrictions on Annual Use of Non-Renewable Fuels at Renewable Facilities

Renewable fuel use facilities have the potential to provide specific benefits to the SGIP including emission benefits and reduced use of natural gas. There is an emphasis on ensuring that renewable fuel use facilities are in fact using renewable resources as their primary source of fuel. In accordance with CPUC Decision 02-09-051, renewable fuel use facilities cannot receive more than twenty-five percent of their annual input energy from non-renewable sources. Moreover, PAs are required to submit reports every six months reviewing the status of renewable fuel use reports to meet the requirements.[5]

At the end of 2005, there were twenty renewable fuel use projects on-line in the SGIP with an estimated combined generating capacity of approximately 5.2 MW. Renewable fuel use reports (RFUR) that review the status and compliance of renewable fuel use projects are to be provided to the CPUC Energy Division every six months. Filing of the RFURs and any actions taken by the PAs as a result of the RFURs represent the means by which the PAs comply with the CPUC decision. RFUR numbers 6 and 7 covered the reporting period encompassing 2005 and provided information on compliance of these SGIP projects with the renewable fuel use requirements. Re-examination of the facility fuel use confirmed that all of the facilities meet the twenty-five percent limit on non-renewable fuel use.

Table 5-12 summarizes the numbers and capacity of renewable fuel use facilities by incentive level and technology type. Microturbine projects represent the greatest number of renewable fuel use facilities. However, due to their generally larger capacity, IC engines represented the single largest capacity of renewable fuel use technology.

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[5] 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…."

Table 5-12: Quantities and Capacities of Renewable Fuel Use Facilities as of 12/31/05

Level	Technology Type	No of Facilities	Rebated Capacity (kW)
3	ICE	1	991
	Microturbine	3	564
3R	Engine	3	960
	Microturbine	11	1,970
1	Fuel Cells	2	750
Total:		**20**	**5,235**

Cost Comparisons Between Renewable and Non-Renewable Facilities

CPUC Decision D.02-09-051 also requires PAs to monitor cost differences between Level 3 and 3-R projects. Level 3-R project costs could fall below Level 3 costs due to Level 3-R projects being exempt from waste heat recovery requirements. As a result, Level 3-R projects could potentially be receiving a greater than necessary incentive level which could lead to fuel switching.

Table 5-13 is a summary of eligible installed costs for Level 1, Level 3 and Level 3-R projects operational as of December 31, 2005. The table shows various project costs on a dollar per watt basis, including minimum, maximum and average values.

Table 5-13: Summary of Eligible Installed Costs for Operational Projects ($/Watt)[6]

Technology	Incentive Level	No. Projects	$/Watt Eligible Installed Costs			
			Minimum	Maximum	Median	Average
Fuel Cell - Ren. Fuel	1	2	$9.41	$9.85	$9.63	$9.63
Fuel Cell - Nonren. Fuel	2	3	$7.10	$19.00	$8.15	$11.42
All Fuel Cells		**5**	**$7.10**	**$19.00**	**$9.41**	**$10.70**
Microturbine - Ren. Fuel	3-R	11	$1.23	$7.01	$3.33	$3.94
Microturbine - Nonren. Fuel	3	75	$0.70	$9.01	$3.06	$3.16
All Microturbines		**86**	**$0.70**	**$9.01**	**$3.17**	**$3.27**
IC Engine - Ren. Fuel	3-R	3	$1.56	$3.22	$2.79	$2.52
IC Engine - Nonren. Fuel	3	141	$0.38	$5.00	$2.09	$2.15
All IC Engines		**144**	**$0.38**	**$5.00**	**$2.09**	**$2.16**

Level 3 and 3-R Microturbine Project Cost Comparison:

There were seventy-five microturbines powered by non-renewable fuels and eleven microturbines operating off of renewable fuels during 2005. For Level 3 microturbines using non-renewable fuels, the average project cost was $3.16 per watt. For Level 3-R microturbine projects using renewable fuels, the average project cost was $3.94 per watt, $0.78 per watt higher than non-renewable powered microturbines. Comparison of median project cost values between the Level 3 and Level 3-R microturbine projects also indicate that most renewable fueled microturbine projects had higher installed costs than their non-renewable fueled counterparts.

Level 3 and 3-R Internal Combustion Engine Cost Comparison:

There were 141 internal combustion (IC) engines using non-renewable fuels during 2005 and only three IC engines powered by renewable fuels. For Level 3 IC engines using non-renewable fuels, the average project cost was $2.15 per watt. For Level 3-R engines operating off of renewable fuel, the average project cost was $2.52 per watt, $0.37 per watt higher than non-renewable powered IC engines. Comparison of the median project cost values also indicate that most renewable fueled IC engine projects had higher installed costs than their non-renewable fueled counterparts.

[6] Eligible installed system cost data was obtained from the Program tracking system files provided to Itron by the Program Administrators on a monthly basis. Operational projects are defined as projects for which an incentive check has been issued.

Gas Clean Up Costs for Renewable Fuel Projects:

Unlike natural gas, biogas typically contains significant quantities of moisture, hydrogen sulfide and other contaminants that can cause damage to the internal components of prime movers (e.g., the microturbine, IC engine or fuel cell). Consequently, renewable fuel use projects commonly employ gas clean up equipment to protect the prime mover. Gas clean up costs represent the likeliest cause of higher costs for renewable fuel use projects. To assess the impacts of the increased costs, gas clean up costs were examined for fuel cells, IC engines and microturbines powered by renewable fuels.[7]

It is difficult to draw sound conclusions about incremental gas clean up costs for fuel cells and renewable IC engines due to the small number of operating systems. In particular, there were only four fuel cell systems operating during 2005, split evenly between renewable and non-renewable fuels. However, there is a significant range in the non-renewable fuel cell costs per watt, making the average a questionable indicator of the typical cost. In general, the incremental cost of gas clean up equipment on fuel cells should be approximately represented by the difference in the average cost of a non-renewable fuel powered fuel cell and a renewable fuel powered fuel cell. 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 off of cleaner fuels such as natural gas. If the minimum project cost of a fuel cell operating off of non-renewable fuel is used instead of the average, then the difference between non-renewable and renewable powered fuel cells is on the order of $2.50 per watt. Outside information sources were examined to see if $2.50 per watt seemed a reasonable proxy for the incremental gas clean up systems for renewable powered fuel cells. However, due to the variability in digester gas constituents and the differing types of fuel cells, it was impossible to develop an accurate and representative incremental gas clean up cost estimate.

On a similar note, there were only three renewable-fueled IC engine projects operational during 2005. The wide range of project costs per watt on the three systems and the small sample size makes an average value questionable over the long term. Given these caveats, a comparison between the average cost per watt of renewable and non-renewable IC engines shows an incremental cost difference of $0.37 per watt. This value represents a proxy of the additional cost for gas clean up associated with operating IC engines with renewable fuels.

Comparisons between renewable and non-renewable microturbine are somewhat more reasonable given the larger sample sizes. Based on the average cost per watt, the incremental cost for gas clean up on microturbines is approximately $0.78 per watt.

[7] Although the term renewable fuel is used in the report, in all cases, renewable fuel relates to biogas derived from one of three sources: landfill gas; digester gas from wastewater treatment facilities; and “biogas” from anaerobic digesters operated at dairies.

In summary, comparison of the installed costs between renewable and non-renewable fueled generation systems operational as of December 31, 2005 confirms that most non-renewable generators are less capital intensive than their renewable-fueled counterparts. Similarly, it appears that the differences in capital cost between renewable and non-renewable fueled generators may be due mainly to increased gas clean up required on the renewable powered systems.

Greenhouse Gas Emission Reductions

Increased interest and concern over greenhouse gas (GHG) emissions prompted an examination of the impact of GHG emissions from SGIP projects. The net change in GHG emissions due to the operation of SGIP systems on-line during PY05 was quantified to determine whether the program leads to a net reduction of GHG emissions. As reported by the U.S. Environmental Protection Agency (EPA), the primary GHG emitted in the U.S. is carbon dioxide (CO_2) , most of which stems from fossil fuel combustion. In 2004, CO_2 represented approximately 85 percent of all U.S. GHG emissions for the year. For GHG emissions originating in the state of California, CO_2 emissions make up approximately the same percentage of total GHGs as they do for the nation – about 84 percent.[8] The other greenhouse gases primarily responsible for global climate change include methane (CH_4), nitrous oxide (N_2O), and fluorinated gases (chlorofluorocarbons [CFCs], hydrochlorofluoro-carbons [HCFCs], and halons).

GHG emissions considered in this analysis focused on CO_2 and CH_4 as these two pollutants are commonly associated with emissions characteristic of SGIP project operations. Net emission reductions of these pollutants are quantified in this analysis by examining GHG emissions that occur during the following processes:

- When in operation, power generated by SGIP facilities directly displaces grid electricity that would have been generated from central station power plants.[9] As a result, SGIP projects displace the accompanying CO_2 emissions that these central station power plants would have released to the atmosphere. CO_2 emissions from these central station power plants are estimated on an hour by hour basis over all

[8] California Energy Commission. Inventory of California Greenhouse Gas Emissions and Sinks: 1990 to 2004. Draft Staff Report No. CEC-600-2006-013-D. pp. 6.

[9] In this analysis, we compare GHG emissions from SGIP facilities only to GHG emissions from utility power generation that could be subject to economic dispatch (i.e., central station natural gas-fired combined cycle facilities and simple cycle gas turbine peaking plants). We assume that operation of SGIP facilities have no impact on electricity generated from utility facilities not subject to economic dispatch. Consequently, comparison of SGIP facilities to nuclear or hydroelectric facilities is not made as neither of these facilities are subject to dispatch.

8760 hours of the 2005 year[10]. The CO_2 emission estimates are based on a methodology developed by Energy and Environmental Economics, Inc. (E3).[11]

- The operation of specific cogeneration systems such as microturbines (MT), fuel cells (FC), gas turbines (GT), and reciprocating internal combustion engines (ICE) emits CO_2. While CO_2 emissions from central power plants are avoided due to SGIP systems, SGIP cogeneration plants themselves are responsible for the generation of CO_2 emissions. Emissions of CO_2 from SGIP facilities are estimated based on hour by hour electricity generated from SGIP facilities over all 8760 hours of the 2005 year.
- Waste heat recovered from the operation of cogeneration systems displaces natural gas that would have been used to fuel boilers responsible for producing process heating at the customer host site. This displaces accompanying CO_2 emissions from the boilers, which are taken into account by calculating the CO_2 emissions avoided from using natural gas to fuel boilers. Since virtually all fuel carbon in natural gas is converted to CO_2 during combustion, the amount of CH_4 released from incomplete combustion is considered insignificant and is not included in the estimated reduction in GHG from SGIP systems.
- Recovery of waste heat also displaces electricity (and the accompanying CO_2) emissions that would have been used to operate electric chillers. Estimates of CO_2 emissions are based on the hour by hour electricity savings from central station facilities.
- Renewable fuel use facilities (i.e., those facilities that use biogas as a fuel source) with a capacity less than 400 kW, such as dairies, small landfill sites, and small wastewater treatment plants, are assumed to capture CH_4 that typically would have been vented and instead, use it for energy purposes. The avoided CH_4 emissions are a direct reduction of greenhouse gases. For biogas generated from wastewater treatment facilities and landfill gas recovery operations that are used in SGIP facilities equal to or greater than 400 kW in rebated capacity, it was assumed this biogas would have been flared if not used at a SGIP renewable fuel use facility. Flaring was assumed to have essentially the same degree of combustion completion as SGIP renewable fuel use facilities. Consequently, for the renewable fuel use facilities equal to or larger than 400 kW, there is no net CH_4 benefit.

[10] Consequently, during those hours when a SGIP facility is not in operation, displacement of CO_2 emissions from central station power plants is equal to zero.

[11] Energy and Environmental Economics for the California Public Utilities Commission, "Methodology and Forecast of Long Term Avoided Costs for the Evaluation of California Energy Efficiency Programs," October 25, 2004.

Table 5-14 presents the SGIP technologies for which GHG net emission reductions can be estimated, as well as the sources of the estimated change in these emissions.

Table 5-14: SGIP Technologies for Which GHG Emission Reductions are Estimated

Program Incentive Category	Eligible Generation Technologies	GHG Emissions from SGIP generation (CO_2)	GHG Emissions from displaced boiler fuel (CO_2)	GHG Emissions from displaced methane (CH_4)
Level 1	Renewable fuel cells	Yes, CO_2 emissions from fuel cell reformer exhaust	Yes; for those fuel cell projects that used cogeneration and recovered waste heat	Yes; methane from biogas fed into fuel cell
	Photovoltaic	Yes, displaced electricity from grid	NA	NA
	Wind turbines	Yes, displaced electricity from grid	NA	NA
Level 2	Non-renewable fuel cells	Yes, CO_2 emissions from fuel cell reformer exhaust	Yes; for those fuel cell projects that used cogeneration and recovered waste heat	No
Level 3-R	Renewable fueled MT	Yes, CO_2 emissions in exhaust of the MT	Yes; for those MT projects that used cogeneration and recovered waste heat	Yes; methane from biogas fed into MT
	Renewable fueled ICE and small GT	Yes, CO_2 emissions in the exhaust from natural gas ICE and GT	Yes; for those ICE and GT projects that used cogeneration and recovered waste heat	Yes; methane from biogas fed into ICE and GT
Level 3-N	Non-renewable and waste gas fueled MT	Yes, CO_2 emissions in exhaust of the MT	Yes; for those MT projects that used cogeneration and recovered waste heat	No
	Non-renewable and waste gas fueled ICE and small Gt	Yes, CO_2 emissions in the exhaust from natural gas ICE and GT	Yes; for those ICE and GT projects that used cogeneration and recovered waste heat	No

The following equation describes how the net change in greenhouse gas emissions was quantified for the 2005 Impacts Evaluation Report:

Net Change in GHG Emissions = *GHG Emissions from Grid Power Plants (term 1)*
– Emissions Released from Cogeneration Systems (term 2)
– Avoided Emissions from Electric Generation from use of Recovered Waste Heat for Electric Chillers (term 3)
– Avoided Emissions from use of Recovered Waste Heat for Natural Gas Boilers (term 4)
– Avoided Emissions from use of Captured Methane at Renewable Fuel Use Facilities (term 5)

The methodology for estimating the net difference in GHG emissions between central station power plants and SGIP facilities relies on multiplying emission factors that are technology, pollutant (i.e., CO_2 or CH_4), utility, and project-specific by the amount of electricity generated over each of the 8760 hours of 2005. For example, for the CO_2 emissions that would have been emitted from central station power plants (the first term in the above equation), 8760 unique hourly emission values were calculated based upon utility electric avoided cost data prepared by Energy and Environmental Economics, Inc. (E^3).[12] Two streams of 8760 hourly emission factors were developed by E^3; one for Pacific Gas and Electric Company (hereafter these factors will be referred to as the northern California CO_2 emission factors) and the other for Southern California Edison and San Diego Gas and Electric Company (hereafter referred to as the southern California CO_2 emission factors). Inputs to develop the hourly emission values are geographically dependent due to different weather conditions, different central station plant heat rates, and different natural gas market conditions.

The central station power plant CO_2 values developed by E^3 are based upon the assumption that the marginal power plant relies on natural gas to generate electricity. By using forward market prices, E^3 established the price of natural gas for each hour over a year presented as the percentage of the annual average price. These northern and southern California “price shape” data dictate the mix of high and low efficiency power plants used by the conventional power grid to meet demand. During the hours where the price of natural gas is high (e.g., weekday, on-peak versus weekend or holiday, off-peak), the demand for electricity is met using high-efficiency as well as low efficiency peaking power plants (“peakers”). The price of natural gas is used to calculate an implied heat rate, which is dependent on the mix of low and high efficiency power plants. This implied heat rate is used to calculate the tons of CO_2 per kWh emission factors for each hour of the year. The greater the demand during these

[12] The filename of the workbook that contains the data used to generate hour-specific emission factors for CO_2 is called cpucAvoided26.xls and can be downloaded from www.ethree.com/CPUC . See Appendix B for a detailed description of the methodology used to calculate CO_2 emission factors.

times (as indicated by a higher hourly price for natural gas), the higher the percentage of electricity generated by peakers and the greater the benefit of relying upon SGIP systems.

Estimates of CO_2 emissions from SGIP facilities (term 2 in the equation) are based on operation of each SGIP facility for each hour of the 2005 year. Electricity and heat data are collected on the SGIP facilities over 8760 hours per year. Consequently, actual performance during each of those 8760 hours is used to estimate hourly CO_2 estimates, which are then summed over 8760 hours of the year. Once summed, the emission estimates are then aggregated by technology (e.g., reciprocating internal combustion engines, microturbines, and small gas turbines).

CO_2 emissions are avoided when SGIP facilities use waste heat recovery systems in lieu of burning natural gas in boilers to produce process heat (term 3 of the equation). Estimates of the avoided CO_2 emissions are based on the amount of heat recovery achieved for each SGIP cogeneration facility on an hourly basis over 8760 hours of the year, and assumes complete combustion (i.e., combustion results in only CO_2 emissions and no emissions of carbon monoxide). Additionally, CO_2 emissions are avoided when recovered waste heat is used in electric chillers (term 4 of the equation). The avoided CO_2 emissions are due to electricity displaced from central station power plants. The amount of displaced electricity due to waste heat-driven chillers is estimated using the hourly amount of waste heat recovered from SGIP facilities with waste heat absorption chillers, and the performance of the chiller.

Lastly, SGIP facilities that capture and use biogas that would have otherwise be released to the atmosphere represent avoided methane emissions (term 5 of the equation). The method for estimating avoided methane emissions is described below, followed by a description of the methodology used to estimate avoided carbon dioxide emissions.

Methane Emission Reductions

Calculation of methane emission reductions was carried out for the subset of renewable fuel use facilities in the SGIP program, which includes renewable-powered fuel cells, renewable-fueled microturbines, renewable-fueled internal combustion engines, and renewable-fueled small gas turbines. Methane used in these facilities represents methane captured and harnessed for use in renewable fuel used facilities. Consequently, this methane was no longer emitted to the atmosphere.[13] By definition, renewable fuel use facilities in the SGIP rely on a minimum of seventy-five percent of their annual fuel input (on an energy basis)

[13] Baseline treatment of these biogas-based fuels (i.e., the venting or flaring of biogas if not harnessed and used for energy purposes) was taken into consideration in determining net GHG emissions. For example, methane gas from open lagoons at dairies is typically vented directly to the atmosphere. The same is true for small landfills and wastewater treatment facilities generally under 400 kW in capacity. Consequently, for purposes of this report, the baseline treatment of biogas fuels was considered as venting for all facilities less than 400 kW in equivalent power capacity. For all facilities 400 kW and greater, the baseline treatment was considered to be flaring.

from renewable fuels.[14] Almost all renewable fuel use facilities in the SGIP rely exclusively on renewable fuels as their source of fuel. However, a few facilities use natural gas or propane for start up or "piloting." Generally, the amount of non-renewable fuel use constitutes less than one percent of their annual energy input. As metered FUEL data are not available for these facilities, the analysis assumes these facilities use renewable fuel for 100 percent of their fuel needs. Similarly, those engines, microturbines, and fuel cell facilities that rely primarily on natural gas but are able to occasionally use biogas are assumed to rely completely on natural gas. Hence, no methane emission reductions are assumed to occur from these systems. Where data were available on dual-fueled SGIP facilities in the SGIP tracking data, the additional captured methane emissions were included in this estimate.

An analysis of the SGIP tracking data showed a list of 20 facilities that relied upon renewable fuels during 2005. The total electricity generated from these sites was multiplied by a factor of 246 grams of CH_4 per kWh to calculate the total CH_4 emissions avoided by relying upon methane to generate power from these SGIP facilities.[15] Table 5-15 presents the tons of CH_4 emissions avoided and tons of CO_2 equivalent[16] by technology. This table shows that renewable fueled microturbines are responsible for the largest reduction of methane emissions, followed by renewable internal combustion engines.

Table 5-15: Reduction of CH_4 Emissions from Renewable Fuel SGIP Systems in 2005 (in Tons of CH_4 and Tons of CO_2 equivalent)

Technology	Tons of CH_4 Reduced	Tons of CO_2 eq. Reduced
Fuel Cells	178	3,742
Internal Combustion Engines	438	9,204
Microturbines	1,723	36,176
Total	**2,339**	**49,122**

To put this result in perspective, the most recent inventory of greenhouse gas emissions for the state of California estimates that methane emissions in 2004 were equal to 27.8 MMT of

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[14] Although wind and solar are renewable energy resources, renewable use fuel in the context of examining methane reductions is limited to technologies that rely upon biogas fuels containing methane collected from anaerobic digestion processes (e.g., landfill gas, waste water treatment "digester" gas, and digester gas from animal manure digesters)

[15] See Appendix B for the derivation of the CH_4 emission factor of 246 grams per kWh.

[16] Carbon dioxide equivalent is a metric measure used to compare the emissions of various greenhouse gases based upon their global warming potential (GWP). The carbon dioxide equivalent for a gas is derived by multiplying the tons of the gas by the associated GWP. For example, the global warming potential of methane over 100 years is 21. This means that one million metric tons of methane are equivalent to emissions of 21 million metric tons of carbon dioxide over the 100 year time horizon. OECD Glossary of Statistical Terms, http://stats.oecd.org/glossary/detail.asp?ID=285

CO_2 equivalent[17]. Reduction of methane from the SGIP renewable fuel use projects is equal to approximately 0.2% of California's methane emissions.

Table 5-16 presents the reduction of methane emissions by PA and SGIP technology. As this table shows, the PA that has reduced the largest quantity of methane emissions is PG&E followed by SCE. In fact, those SGIP projects overseen by PG&E are responsible for over 60 percent of the methane reductions during the 2005 program year. Southern California Gas Company (SCG) is not included in this table because it was not the PA for any of the SGIP projects that affected methane emissions. In other words, SCG did not oversee renewable fuel SGIP projects during the 2005 program year.

Table 5-16: Reduction of CH_4 Emissions from Renewable Fuel SGIP Systems in 2005 by Program Administrator and Technology (in Tons of CH_4 and Tons of CO_2 equivalent)

Program Administrator	Technology	Tons of CH_4 Reduced	Tons of CO_2 eq. Reduced
PG&E	Fuel Cells	-	-
	Microturbines	438	21,169
	IC Engines	1,008	9,205
	PG&E TOTAL	1,446	30,373
SCE	Fuel Cells	178	3,742
	Microturbines	643	13,497
	IC Engines	-	-
	SCE TOTAL	821	17,239
SDREO*	Fuel Cells	-	-
	Microturbines	72	1,509
	IC Engines	-	-
	SDREO TOTAL	72	1,509
All	**TOTAL**	**2,339**	**49,122**

* SDREO is the PA for SDG&E.

Carbon Dioxide Emission Reductions

The net change in CO_2 emissions from SGIP systems requires an estimate of the emissions avoided from reduced reliance on central station power plants and natural gas (to fuel gas boilers and operate chillers) and the emissions generated from the SGIP cogeneration sites. For the 784 SGIP sites for which electric net generation output data exist, the avoided emissions of CO_2 from the grid were calculated. In addition, the avoided emissions from the use of recovered waste heat to fuel boilers and to operate absorption chillers is also included

[17] California Energy Commission. Inventory of California Greenhouse Gas Emissions and Sinks: 1990 to 2004. Draft Staff Report No. CEC-600-2006-013-D. pp. 64.

in the calculation of reduced emissions, since boilers would have otherwise used natural gas and conventional centrifugal electric chillers. Lastly, CO_2 emissions generated from SGIP systems were also taken into account. In fact, it is possible that SGIP systems generate more CO_2 emissions than they actually reduce. In these cases, the net tons of CO_2 emissions reduced would be negative. For any given site, the CO_2 hourly emission factors account for the geographical location of the site (e.g., whether it is located in northern or southern California), the technology type used at the site, and whether the site uses renewable fuels and recovered waste heat for use in boilers and absorption chillers, if these are present at the location.

Table 5-17 presents the net change in CO_2 emissions from the operation of SGIP systems during 2005. Reductions in emissions are presented by program incentive category and technology type. The single greatest reduction in CO_2 emissions (at over 95 percent of the total) stems from Level 1 projects, with the vast majority of the Level 1 reduction coming from PV projects. Level 2 and Level 3-R projects account for much smaller proportions of the CO_2 emission reductions. In fact, renewable fueled microturbines and non-renewable and waste gas fueled microturbines result in negative net reductions of CO_2. This means these projects emit more emissions of CO_2 than they reduce. Negative tons of CO_2 emissions reduced are possible because these estimates take into account CO_2 emissions released by SGIP technologies while they are in operation.

Table 5-17 also presents the annual energy impact and CO_2 reduction factor for each technology. The annual energy impact presents the MWh generated by each technology group of SGIP projects while the ratio presents the number of tons of CO_2 reduced per MWh of electricity produced for each technology type. The projects with the highest ratios are PV and Wind Turbine projects, with CO_2 factors of 0.61 and 0.60, respectively. Renewable fueled microturbines and non-renewable and waste gas microturbines both have negative ratios (-0.23 and -0.15, respectively) because these projects, on net, increase CO_2 emissions. The CO_2 factor therefore shows the number of tons of emissions increased per MWh of electricity produced from these projects.

Table 5-17: Reduction of CO_2 Emissions from SGIP Systems in 2005 (Tons of CO_2)

Program Incentive Category	Eligible Technologies	Tons of CO_2 Emissions Reduced	Annual Energy Impact (MWhr)	CO_2 Factor (Tons/MWhr)
Level 1	Renewable fuel cells	463	2,637	0.18
	Photovoltaics	40,164	65,915	0.61
	Wind Turbines	1,217	2,038	0.60
Level 2	Non-renewable fuel cells	2,114	11,164	0.19
Level 3 (Renewable) and Level 3-R	Renewable fueled MT	-2,016	8,906	-0.23
	Renewable fueled ICE	335	7,302	0.05
	Small gas turbines	N/A	NA	NA
Level 3 (Nonrenewable) and Level 3-N	Non-renewable and waste gas fueled MT	-4,927	32,498	-0.15
	Non-renewable and waste gas fueled ICE	4,583	332,629	0.01
	Small gas turbines	1,747	18,160	0.10
Total	**All Technologies**	**43,680**	**NA**	**NA**

In the year 2004, the CO_2 net emissions for California were equal to 344.5 million metric tons (MMT). The CO_2 reductions from SGIP projects during the 2005 program year represent approximately 0.08 % of the state's total CO_2 emissions.

In addition to presenting the reduction in CO_2 emissions by technology, we conducted an examination of these emissions reduced by PA and technology. This information is presented in Table 5-18 through Table 5-21 along with the energy impacts by PA and technology. As in the case with methane emissions, those cogeneration projects overseen by PG&E are responsible for the largest proportion of CO_2 emission reductions, followed behind by SCE. In fact, PG&E territory projects result in approximately 50 percent of the CO_2 emissions reduced.

Using the emission reductions and energy generated by PA and technology, CO_2 factors, as defined earlier, are calculated to provide estimates of the amount of emissions reduced per MWh of electricity produced. As shown in the set of tables below, the PA-specific ratios are highest for PV projects and tend to be lowest for Level 3-R and 3-N projects. In fact, similar to the technology specific CO_2 factors presented in Table 5-17, the PA- and technology-specific factors are negative for renewable fueled microturbines for all but SCG and are negative for non-renewable and waste gas fueled microturbines for all but PG&E. Again, these negative factors means that these projects, on average, net an increase in CO_2 emissions per MWh of electricity produced.

Table 5-18: Technology Specific CO_2 Reductions for PG&E

Incentive Level	Technology	Tons of CO_2 Reduced	Energy Impact in MWh	CO_2 Factor (Tons/MWhr)
Level 1	Renewable fuel cells		NA	NA
	Photovoltaics	20,320	34,137	0.60
	Wind Turbines	NA	NA	NA
Level 2	Non-renewable fuel cells	1,986	10,551	0.19
Level 3-R	Renewable fueled MT	-829	3,863	-0.003
	Renewable fueled ICE	54	1,783	0.03
	Small gas turbines	NA	NA	NA
Level 3-N	Non-renewable and waste gas fueled MT	-1,326	9,370	0.14
	Non-renewable and waste gas fueled ICE	927	104,735	0.009
	Small gas turbines	843	11,579	0.07
	Level 3, 3-R, and 3-N Total	-331	131,330	-0.003
	TOTAL	**21,644**	**176,018**	**0.12**

Table 5-19: Technology Specific CO_2 Reductions for SCE

Incentive Level	Technology	Tons of CO_2 Reduced	Energy Impact in MWh	CO_2 Factor (Tons/MWhr)
Level 1	Renewable fuel cells	463	2,637	0.18
	Photovoltaics	7,397	11,707	0.63
	Wind Turbines	1,217	2,038	0.60
Level 2	Non-renewable fuel cells	NA	NA	NA
Level 3-R	Renewable fueled MT	-1,151	4,751	-0.02
	Renewable fueled ICE	280	5,519	0.05
	Small gas turbines	NA	NA	NA
Level 3-N	Non-renewable and waste gas fueled MT	-1,102	7,768	-0.14
	Non-renewable and waste gas fueled ICE	674	45,049	0.015
	Small gas turbines	NA	NA	NA
	Level 3, 3-R, and 3-N Total	-1299	63,086	-0.02
	TOTAL	**6,479**	**79,468**	**0.08**

Table 5-20: Technology Specific CO_2 Reductions for SCG

Incentive Level	Technology	Tons of CO_2 Reduced	Energy Impact in MWh	CO_2 Factor (Tons/MWhr)
Level 1	Renewable fuel cells	NA	NA	NA
	Photovoltaics	6,565	10,664	0.61
	Wind Turbines	NA	NA	NA
Level 2	Non-renewable fuel cells	NA	NA	NA
Level 3-R	Renewable fueled MT	NA	NA	NA
	Renewable fueled ICE	NA	NA	NA
	Small gas turbines	NA	NA	NA
Level 3-N	Non-renewable and waste gas fueled MT	-2,025	12,000	-0.17
	Non-renewable and waste gas fueled ICE	2,612	161,197	0.16
	Small gas turbines	904	6,581	0.14
	Level 3, 3-R, and 3-N Total	1491	179,778	0.008
	TOTAL	**9,547**	**190,442**	**0.05**

Table 5-21: Technology Specific CO_2 Reductions for SDREO

Incentive Level	Technology	Tons of CO_2 Reduced	Energy Impact in MWh	CO_2 Factor (Tons/MWhr)
Level 1	Renewable fuel cells	NA	NA	NA
	Photovoltaics	5,881	9,408	0.63
	Wind Turbines	NA	NA	NA
Level 2	Non-renewable fuel cells	129	613	0.21
Level 3-R	Renewable fueled MT	-36	292	-0.006
	Renewable fueled ICE	NA	NA	NA
	Small gas turbines	NA	NA	NA
Level 3-N	Non-renewable and waste gas fueled MT	-475	3,360	-0.14
	Non-renewable and waste gas fueled ICE	371	21,648	0.02
	Small gas turbines	NA	NA	NA
	Level 3, 3-R, and 3-N Total	-140	25,301	-0.006
	TOTAL	**5,730**	**35,322**	**0.16**

An additional examination of CO_2 emissions from SGIP systems was conducted to determine the sources of the net reductions in CO_2. Table 5-22 presents the CO_2 emissions associated with SGIP facilities by program incentive category and technology type. CO_2 emission sources include those directly displaced from the power plants in the grid through the use of SGIP generation systems; the CO_2 emissions released from the operation of SGIP projects; and the indirect displacement of CO_2 emissions from natural gas and electricity due to the use of recovered waste heat for boilers and absorption chillers. As noted earlier, PV and Level 3-N projects represent the largest sources of CO_2 emission reductions tied to direct displacement of grid power generation. The table also shows that CO_2 emissions attributable to operation of SGIP combustion facilities (e.g., engines, microturbines, etc.) contribute more CO_2 emissions than what they displace from grid power generation.[18] In fact, if CO_2

[18] Although fuel cells themselves have no CO_2 emissions from the electrochemical portion of their process, there are CO_2 emissions from reforming of the feedstock resource (e.g., natural gas, biogas, etc.) to produce the hydrogen needed for operation of fuel cells.

emissions from only direct displacement of grid power and the CO_2 emissions resulting from SGIP facilities were taken into account, the SGIP would have a slightly negative overall CO_2 impact.

Table 5-22 confirms what was previously shown in Table 5-17; SGIP projects as a whole provide significant net reductions in CO_2 emissions. The reason for this is the reduction in CO_2 emissions due to displacement of boiler fuel from recovered waste heat by the cogeneration facilities, and displacement of electricity from waste heat driven chillers. When this displacement of boiler fuel and displaced electricity from waste heat chillers are taken into account, the net impact in CO_2 emissions increases from slightly less than a negative 12,000 tons per year to a net benefit of nearly 44,000 tons per year. As a result, the CO_2 emission benefit resulting from the SGIP is largely driven by two sources: the displacement of grid power by SGIP facilities that have no CO_2 emissions (e.g., PV and wind) and waste heat recovery operations of cogeneration facilities that displaces consumption of boiler fuel (usually natural gas).

Table 5-22: Reduction of CO_2 Emissions from SGIP Systems in 2005 Categorized by Direct and Indirect Displacement (Tons of CO_2)

Program Incentive Category	Eligible Technologies	Direct Displacement from Grid	Cogen Emissions Released	Indirect Displacement through Waste Heat Recovery	Indirect Displacement from Absorption Chillers	Net CO_2 Emission Reductions
Level 1	Renewable fuel cells	1,398	-1,184	249	0	463
	Photovoltaics	40,164	0	0	0	40,164
	Wind Turbines	1,217	0	0	0	1,217
Level 2	Non-renewable fuel cells	6,216	-5,013	850	61	2,114
Level 3-R	Renewable fueled MT	4,910	-8,038	710	401	-2,016
	Renewable fueled ICE	3,971	-4,769	1,133	0	335
	Small gas turbines	0	0	0	0	0
Level 3-N	Non-renewable and waste gas fueled MT	18,231	-29,329	5,690	481	-4,927
	Non-renewable and waste gas fueled ICE	184,120	-217,227	32,266	5,425	4,583
	Small gas turbines	10,180	-16,389	7,956	-	1,747
Total	**All Technologies**	**270,407**	**-281,949**	**48,854**	**6,368**	**43,680**

Not all GHG emissions have similar GHG impacts. For example, methane is a very potent GHG pollutant, which has twenty-one times the impact[19] as CO_2. For this reason, GHG emissions are often placed in units of CO_2 equivalent to allow a basis of comparison. Table 5-23 shows the tons of GHG emissions reduced in tons of CO_2 equivalent, broken down by the different SGIP incentive levels and technologies.[20] The total reduction of GHG emissions measured in CO_2 equivalent units is approximately 93,000 tons with the largest portions of these reductions coming from Level 1 photovoltaic projects and from the displacement of natural gas by the capture and use of methane emissions from Level 3-R renewable fuel use projects.

The last column in Table 5-23 presents ratios of the tons of GHG emissions reduced per MWh generated by each technology category for the 2005 program year. Renewable fuel cells have the highest ratio, followed behind by PV and wind turbine projects, while Level 3, 3-R, and 3-N have the lowest. A single ratio for the Level 3, 3-R, and 3-N projects is presented in the table below because we were unable to categorize the Level 3 projects as those relying on renewable or non-renewable fuels. On the whole, we see that all of the technology-specific ratios of tons of GHG emissions reduced per MWh generated are all positive, unlike the CO_2-specific factors we examined for renewable fueled microturbines and non-renewable and waste gas fueled microturbines in the earlier tables. These ratios can be interpreted as the effectiveness of different technology types to reduce or displace the primary greenhouse gas emissions released from fossil fuel combustion.

[19] The impact is generally referred to as “global warming potential” in the climate change literature.

[20] Note that the results in Table 5-17 can be developed by adding the equivalent CO_2 values in Table 5-14 to the direct CO_2 values in Table 5-16.

Table 5-23: Total Net Reduction of GHG Emissions from SGIP Systems Operating in Program Year 2005 (Tons of CO_2 eq.) and Technology-Specific Ratios of Tons of GHG Reductions per MWh

Program Incentive Category	Eligible Technologies	Tons of GHG Emissions Reduced (in CO_2 eq.)	Energy Impact (in MWh)	Tons of GHG Reduced per MWh
Level 1	Renewable fuel cells	4,205	2,637	1.59
	Photovoltaics	40,164	65,915	0.61
	Wind Turbines	1,217	2,038	0.60
Level 2	Non-renewable fuel cells	2,114	11,164	0.19
Level 3-R	Renewable fueled MT	34,160	399,495	0.11*
	Renewable fueled ICE	9,539		
	Small gas turbines	0		
Level 3-N	Non-renewable and waste gas fueled MT	-4,927		
	Non-renewable and waste gas fueled ICE	4,583		
	Small gas turbines	1,747		
Total	**All Technologies**	**92,802**	**481,250**	**0.19**

* Energy Impacts for Level 3, 3-R, and 3-N are not broken out in our results, and therefore we report a single ratio of tons of GHG emissions reduced per MWh for these incentive categories.

6

Incentive-Level System Impacts

6.1 Introduction

This section addresses incentive-level system impacts from SGIP projects that were on-line through the end of PY05. Impacts examined include effects on energy delivery; peak demand; and waste heat utilization and efficiency requirements. Impacts of SGIP specific to each incentive level are examined, both at the program-wide level and at PA-specific level, where appropriate.

Impacts were estimated for all on-line projects regardless of their stage of advancement in the program, as long as they began normal generation operations prior to December 31, 2005. On-line projects include projects for which SGIP incentives had already been disbursed (Complete projects), as well as projects that had yet to complete the SGIP process (Active projects). Not all projects for which impacts were determined were equipped with monitoring equipment. Similarly, some monitoring data had not been received from third party data providers. Consequently, this annual impact evaluation relies on a combination of metered data, statistical methods, and engineering assumptions. Data availability and corresponding analytic methodologies vary by program level and technology.

6.2 Level 1 PV Systems

Available PV system output data were used in the analysis directly. These data were also combined with certain known characteristics of projects (e.g., location, array tilt, system size) to estimate peak demand and energy impacts of the unmetered PV systems. Available metered data were used to calculate ratios representing average PV system power output per unit of rebated system capacity, essentially hourly capacity factors. For unmetered systems generally and for periods when no metered data were available for metered systems, estimates of PV system power output were generally calculated in accordance with the following:

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

Where:

$\hat{ENGO}_{psdh}$ = Predicted net generator output for project *p* in strata *s* on day *d* during hour *h*

Units: kWh

Source: Calculated

S_{ps} = Solar PV system size for project *p* in strata *s*[1]

Units: kW

Source: SGIP Tracking System

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

Units: kWh

Source: Net Generator Output Meters

This approach relies on hour by hour ratios developed along consistent strata lines. In the event that metered data are not available for an unmetered facility, the next most reasonable metered strata observation is used in developing an hourly ratio. For example, if there are no metered data available for a PV system located in SCE, with a specific tilt and location (e.g., inland or coastal) for the a specific hour during the year, then metered data for the same or very closely sized facility in SoCalGas, with the same tilt, and type of location, are used to develop the estimation ratio.

Demand Impact Coincident with CAISO Peak

As noted in Section 5, the 2005 CAISO system peak occurred on July 20 during the hour from 3:00 to 4:00 p.m. (PDT). During this hour the electrical demand for the CAISO reached 45,380 MW. On this day there were 435 SGIP PV systems installed and on-line; with interval-metered data available for 174 of them. Resulting estimates of peak demand impact coincident with the CAISO peak load are summarized in Table 6-1. The estimated peak demand impact corresponds to a coincident hourly capacity factor of 0.46 kW per 1 kW of PV system size (basis: rebated capacity). The total program-level system peak demand impact for Level 1 PV systems is estimated to have been 23 MW.

Table 6-1: Impact of Level 1 PV Projects Coincident with 2005 CAISO Peak

Output Basis	On-Line Systems (n)	On-Line Capacity (kW)	Peak Demand Impact (kW_P)	ISO Peak Ratio (kW_P/kW Rebated)
Metered	174	24,022	11,077	0.46
Estimated	261	25,580	11,479	0.45
Total	**435**	**49,602**	**22,556**	0.46

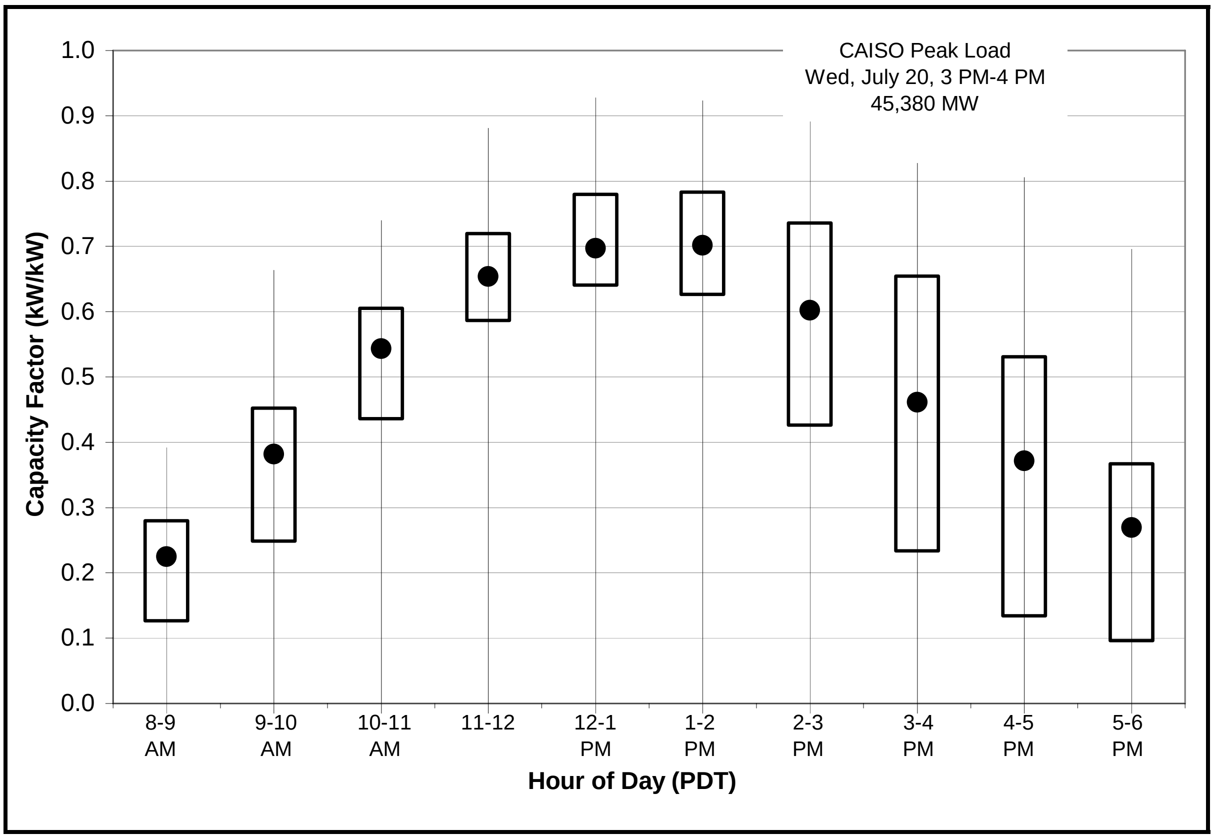
[1] PV ENGO strata included PA, tilt, and location.

The 2004 PV weighted-average CAISO peak demand impact was 0.39 $kW_P/kW_{rebated}$ during the same hour of day, although some 50 days later in early September. The improvement to 0.46 $kW_P/kW_{rebated}$ during the 2005 peak thus is partly a result of the time of the year and the associated better sun angle (i.e., sunlight striking panels closer to perpendicular).

The peak-day operating characteristics of the 174 PV projects for which peak-day interval-metered data were available are summarized in the box plot of Figure 6-1. System sizes were used to normalize power output values prior to plotting summary statistics of PV output data for individual projects. The normalized values represent PV power output per kW of system size. Treatment in this manner enables direct comparison of the power output characteristics of PV systems of varying sizes. The vertically oriented boxes represent ranges within which 75% of project-specific values lie. The vertical lines represent the total range (i.e., maximum and minimum) of project-specific values.

The elongation of the plotted boxes of Figure 6-1 beginning in the hour from 2 to 3 pm appears to be a result of foggy conditions on the afternoon of July 20 in the coastal climate zones of the south coast. Figure 6-2 demonstrates the phenomenon by showing the afternoon declines in normalized output for the IOUs that serve those areas.

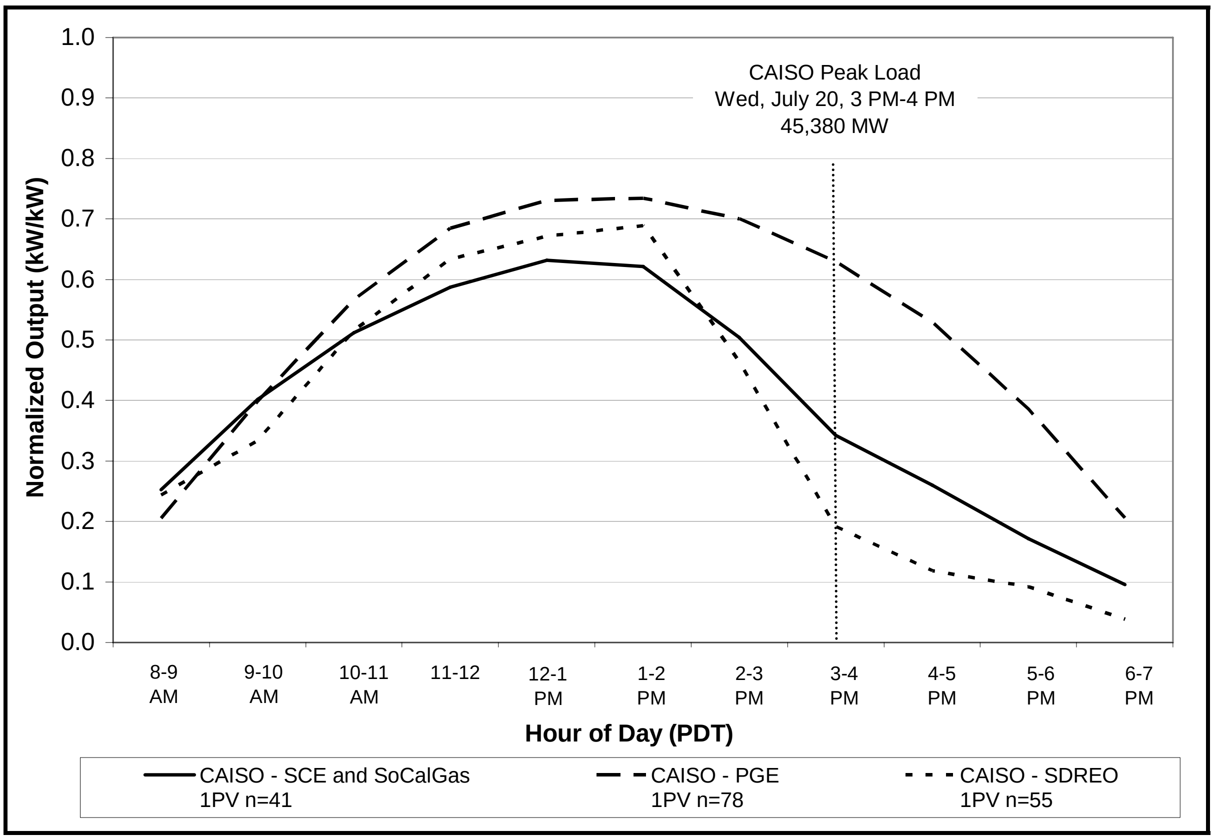
Figure 6-1: 2005 CAISO Peak Day PV Output Profile Summary



The PA-specific generation profiles for the CAISO peak day are presented in Figure 6-2. These profiles of hourly generation output represent weighted averages calculated as the total power output of the metered systems divided by total cumulative rebated capacity of those systems. For each curve in this graphic the total number of metered sites (n) contributing to the generation profile is identified.

On the CAISO 2005 system peak day, Figure 6-2 shows dramatically that PV systems in PG&E's predominantly northern California area outperformed those of SCE, SCG, and SDREO in southern California, especially after 2 pm. The incidence of afternoon fog on this day along the south coast was noted above. Variability in solar resource due to geographical location and such microclimate effects as coastal fog can sharply influence PV output profiles.

Figure 6-2: 2005 CAISO Peak Day PV Output Profiles By PA (July 20)



The individual IOU electric systems experienced their own annual peak loads during different dates and hours of day from the CAISO, as summarized in Table 6-2. SCE and SDG&E experienced their 2005 annual peak loads one day and two days respectively after the July 20 CAISO system peak. PG&E experienced its annual peak load a full week earlier, and at a later hour than either the CAISO or the other IOU systems. SDG&E's peak load hour was the earliest of the IOU peaks, occurring between 3 and 4 pm, the same hour as the CAISO peak. SDG&E's estimated peak demand impact corresponds to a metered coincident hourly capacity factor of 0.60 kW per 1 kW of PV system size (basis: rebated capacity). SCE's and PG&E's peaks occurred one and three hours later respectively than SDREO's, causing their metered coincident hourly capacity factors to be significantly lower than SDREO's during its peak hour.

Table 6-2: Characteristics of 2005 IOU-Specific Peaks

Investor-Owned Utility (IOU)	Day	Hour of IOU System Peak	Peak Load (MW)	PA Peak Ratio (kW_P/kW Rebated)
PG&E	July 14	6-7 p.m.	21,352	0.20
SCE	July 21	4-5 p.m.	22,271	0.44
SDG&E	July 22	3-4 p.m.	4,058	0.60

Figure 6-2 provided PA-specific generation profiles for the CAISO peak day of July 20. Figure 6-3 provides PA-specific generation profiles for the IOU-specific peak days as noted. The generation profiles in this chart are grouped more closely, which suggests that in Southern California the skies were clearer on the days of the southern utilities' IOU-specific electrical system peak loads.

Figure 6-3 demonstrates that PV served SDG&E better than it did PG&E during their respective peak hours. Weighted average normalized output had fallen to 20% for PG&E by the time of its peak load hour between 6 and 7 pm. This makes intuitive sense as there was very little available sunlight between 6 and 7 pm. SCE had a normalized output between 40 and 45%, while SDG&E enjoyed about 55%.

Figure 6-3: 2005 IOU-Specific Peak Day PV Output Profiles By PA

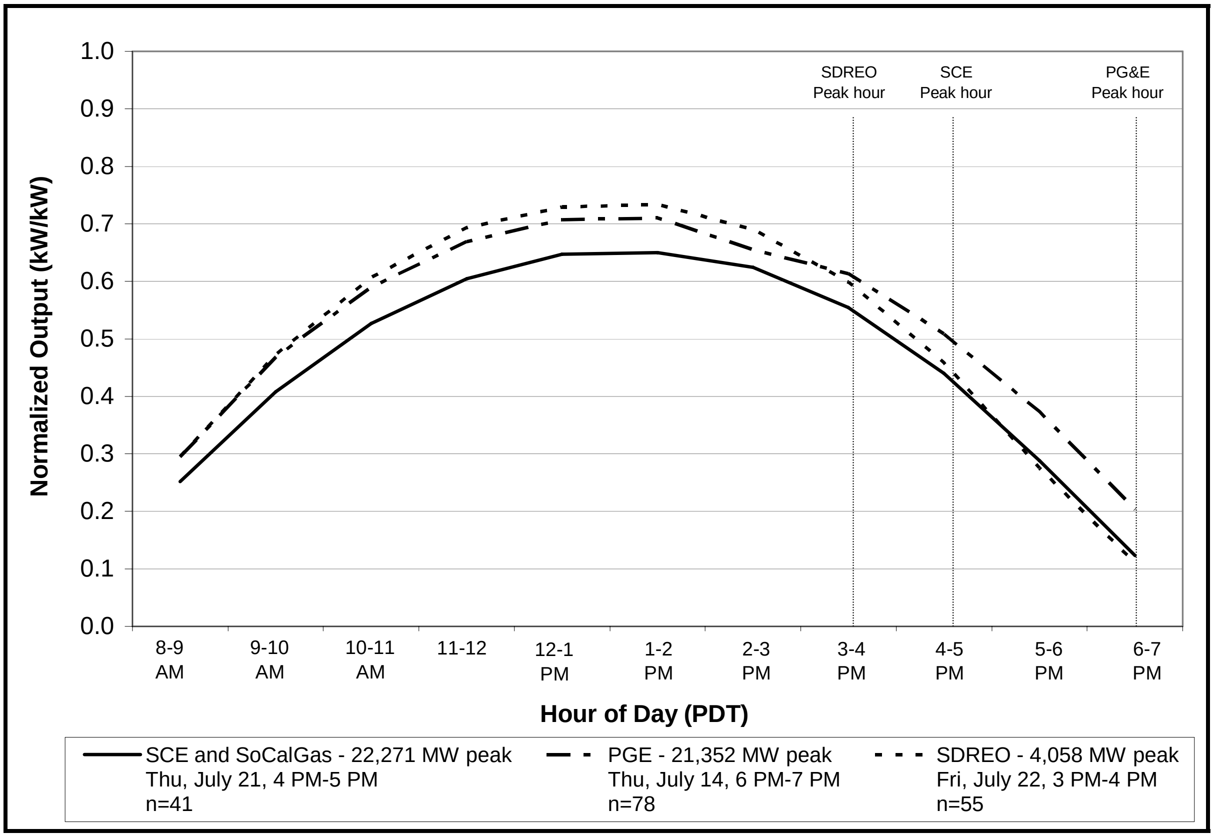


Figure 6-4 shows peak-day profiles of the individual IOUs and the total of the metered and estimated output of their 435 on-line PV systems, along with the CAISO system load plotted separately on right axis. While total PV system power output was substantial on the day of the CAISO system peak, exceeding 33.5 MW, the PV output curve fell off prior to the CAISO peak load hour. After 1 p.m. the output of PV systems began falling, whereas CAISO loads continued to increase for two hours.

Figure 6-4: 2005 CAISO Peak Day System Loads and Individual IOU and Total PV Output

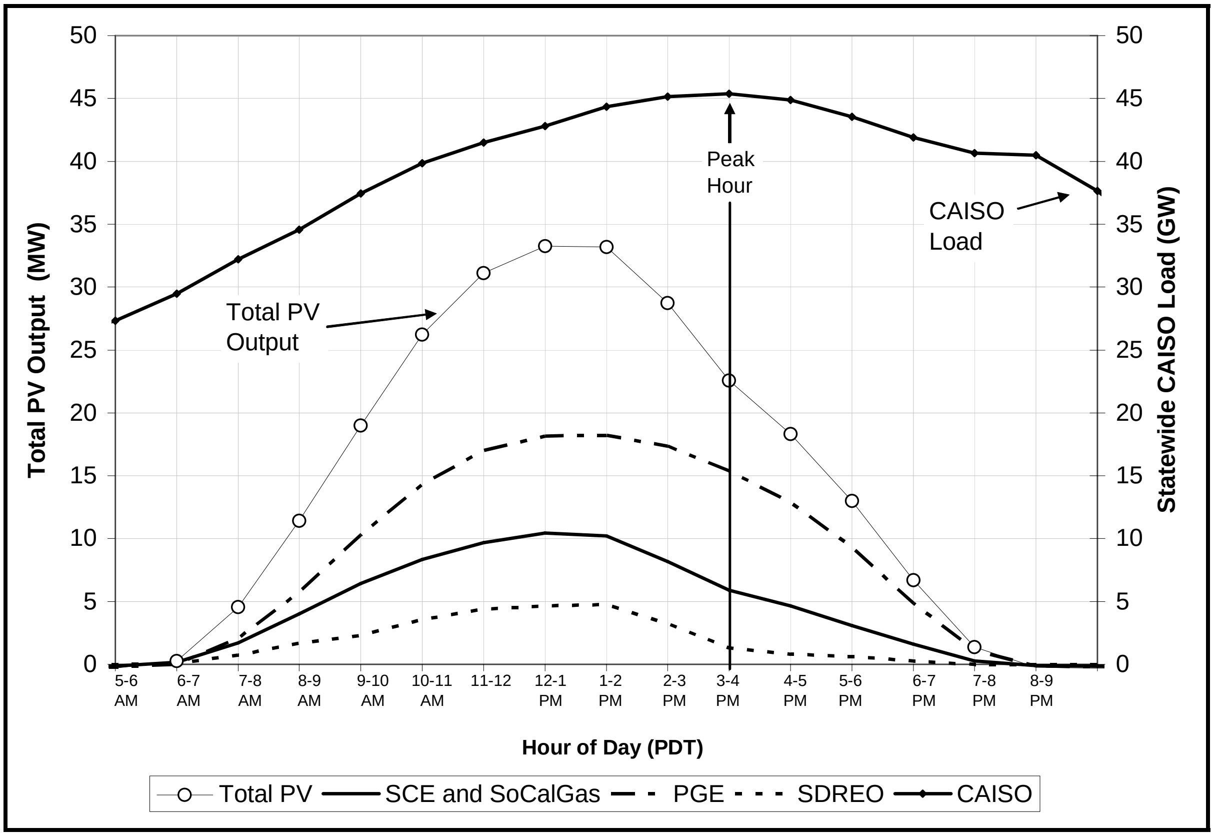


Figure 6-5 through Figure 6-7 summarize PV demand impacts during other peak hours of the year. They demonstrate the precipitous fall of PV peak hour impacts as peak hours occur later in the afternoon. For months from fall, summer, and spring, they show box plots of normalized output during hours coincident with CAISO maximum loads (i.e., 5 peak load hours observed each month). In these charts each of the five box plots summarizes power output of metered PV systems during one of the five hours during which CAISO maximum loads occurred in each month. These five hours potentially can occur on as many as five or as few as one separate days. The horizontal axis lists the date, hour, CAISO load, and the number of PV systems contributing to the normalized output observation. The left-most box plot corresponds to the hour when the maximum CAISO load occurred during the month. The remaining four box plots are arranged in order of descending CAISO load, not in order of hour of day as found in many other figures. Box plots are not provided for winter months because wintertime CAISO loads always reached maximum values during evening hours when PV output was near zero. The results of such late peak hours can be seen in the figures for March, April, and November nevertheless. The weighted average values, depicted in these charts with solid black circles, were calculated as the total power output of the metered systems divided by total cumulative size of those systems. Where it was necessary to calculate estimates of PV power output, weighted averages such as these were applied to known system capacities to yield estimated values.

Figure 6-5: PV Demand Impact – Spring

The top five CAISO load hours in March 2005 occurred in the first 10 days of the month. All the peaks were for the hour from 6 to 7 pm, when virtually statewide the sun already was setting.

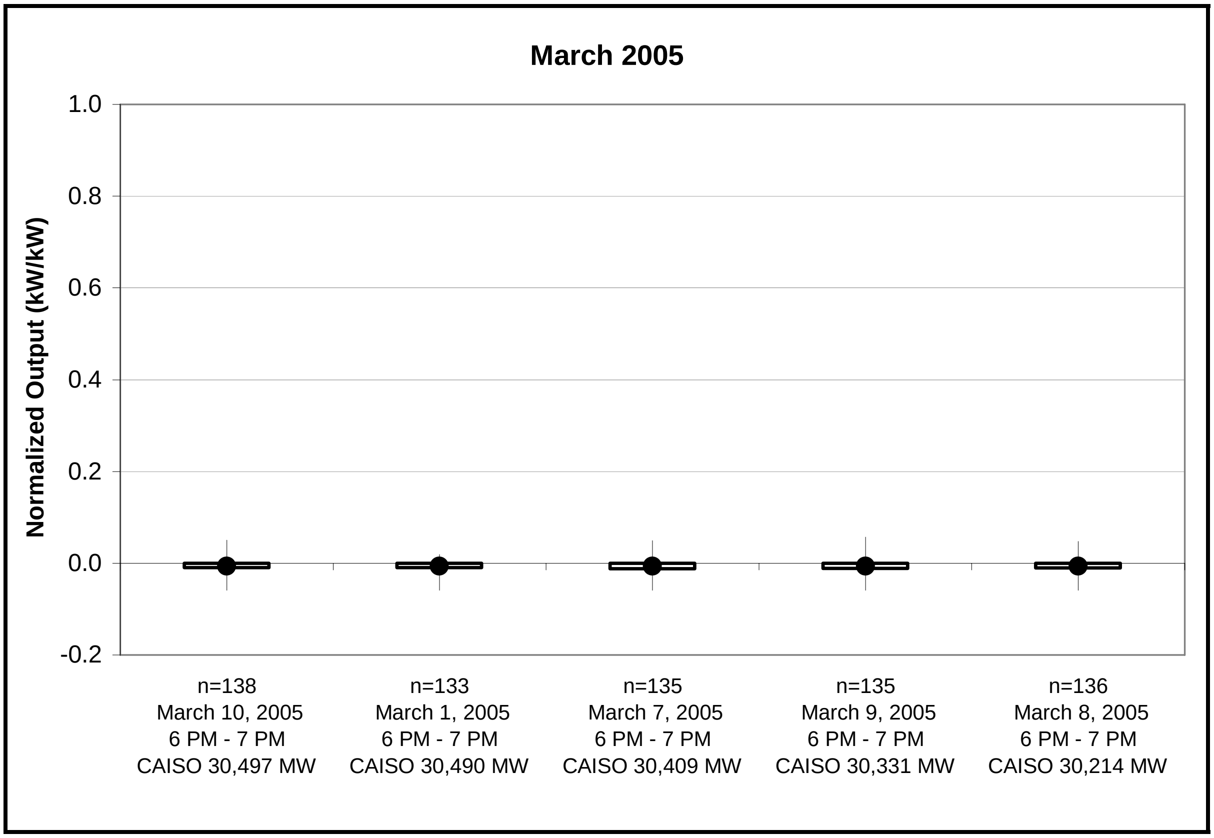


Figure 6–5: PV Demand Impact – Spring (continued)

In April 2005, three of the maximum load hours occurred between 1 pm and 4 pm. Generally clear and cool weather during these periods permitted high output from many systems. The hour nearest noon yielded the highest weighted average of the year.

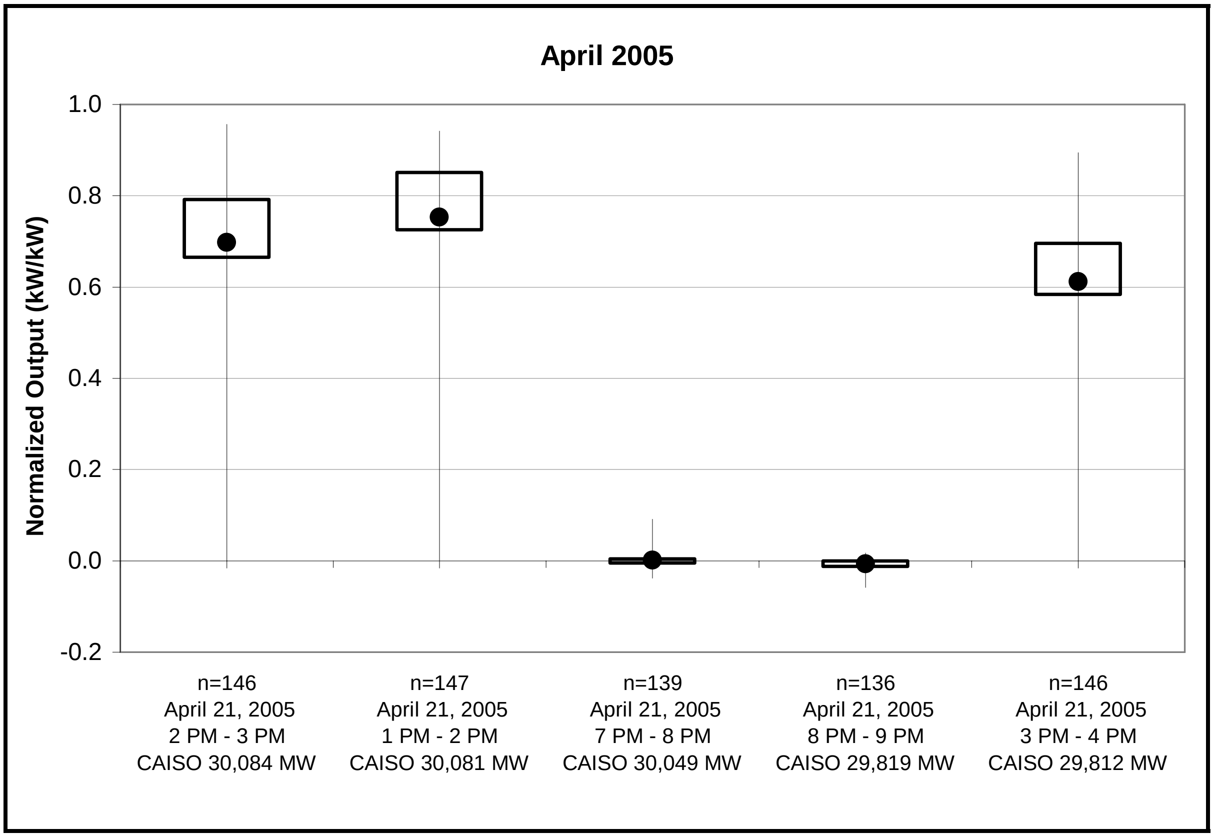


Figure 6–5: PV Demand Impact – Spring (continued)

May 2005 CAISO maximum load hours occurred between 1 pm and 5 pm. Normalized output decreased as the hour grew beyond noon.

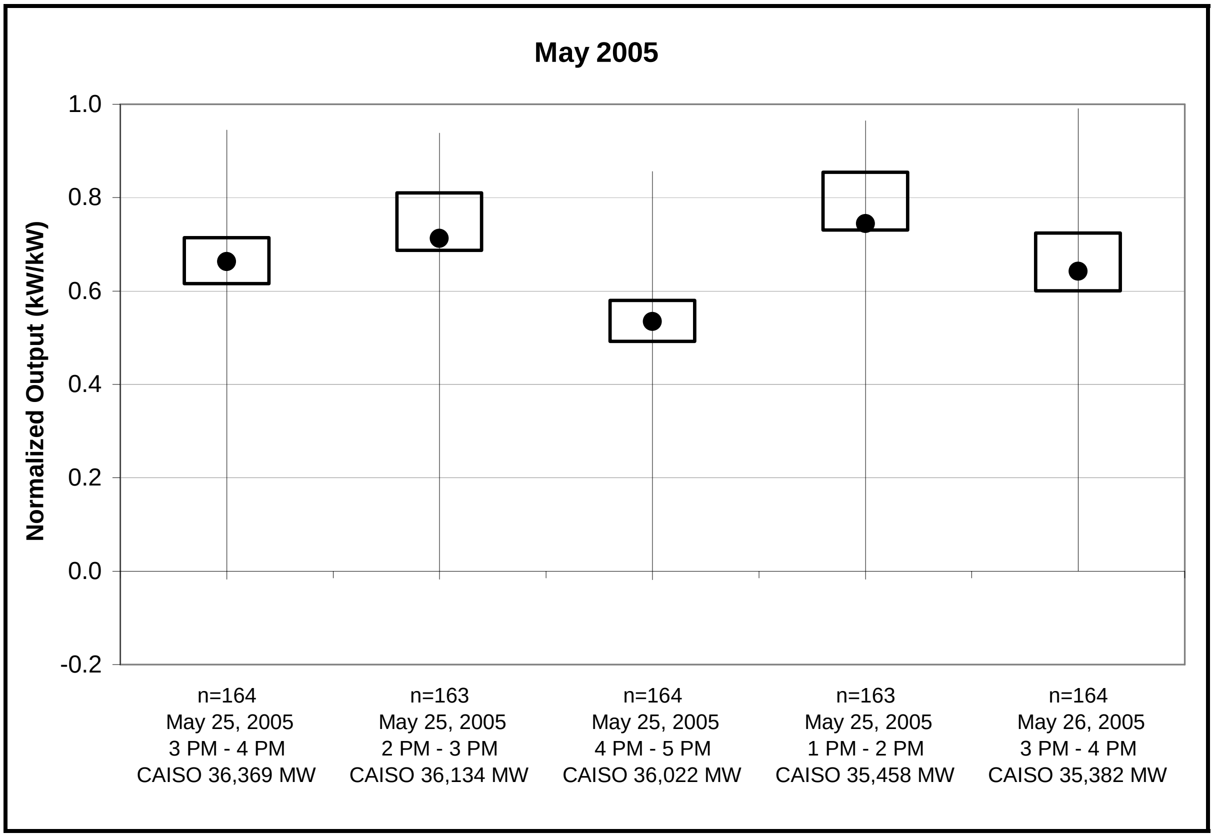


Figure 6-6: PV Demand Impact – Summer

June 2005 CAISO maximum loads occurred between 1 pm and 6 pm. Again, normalized output decreased as the hour grew beyond noon.

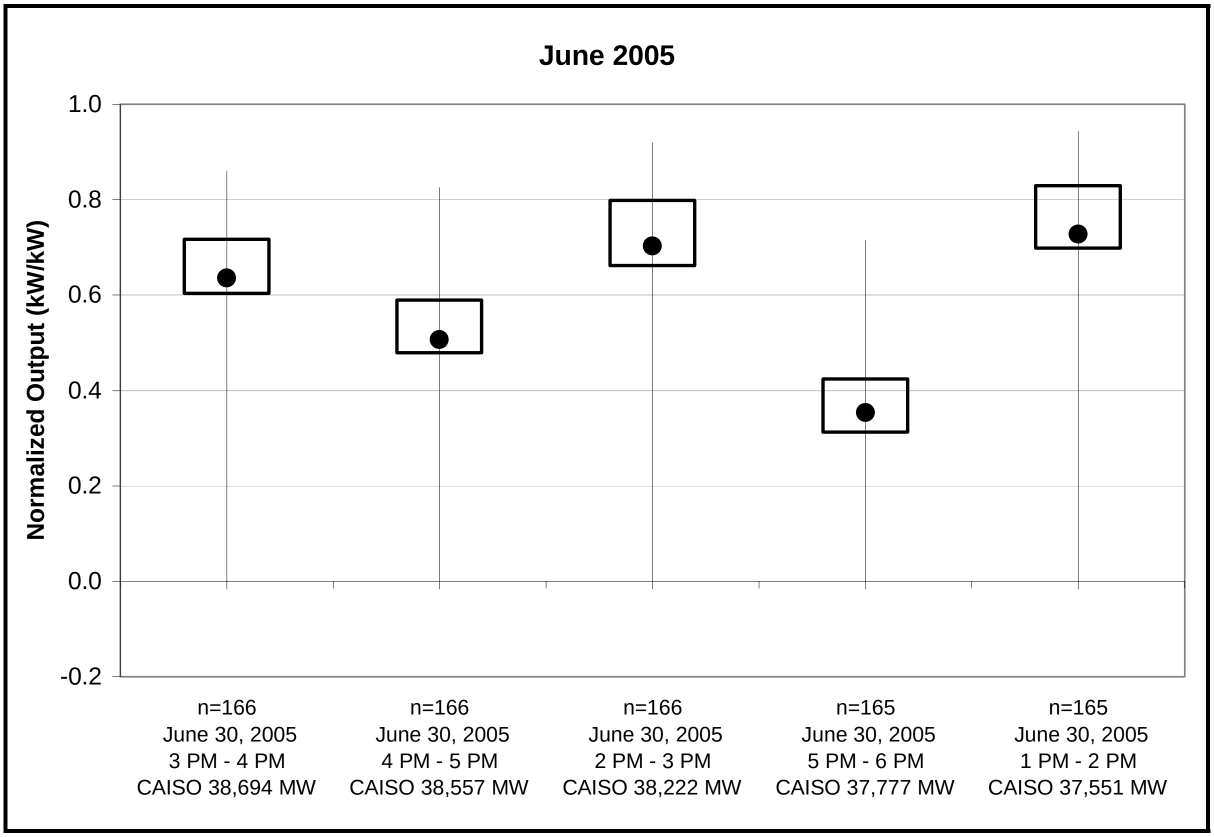


Figure 6–6: PV Demand Impact – Summer (continued)

July 2005 brought the year's five highest CAISO maximum loads. Three occurred on July 20 between 2 pm and 5 pm. On that day after 3 pm, foggy weather along the south coast led to wider than usual variation in PV output. This can be seen in the first and third elongated box plots here.

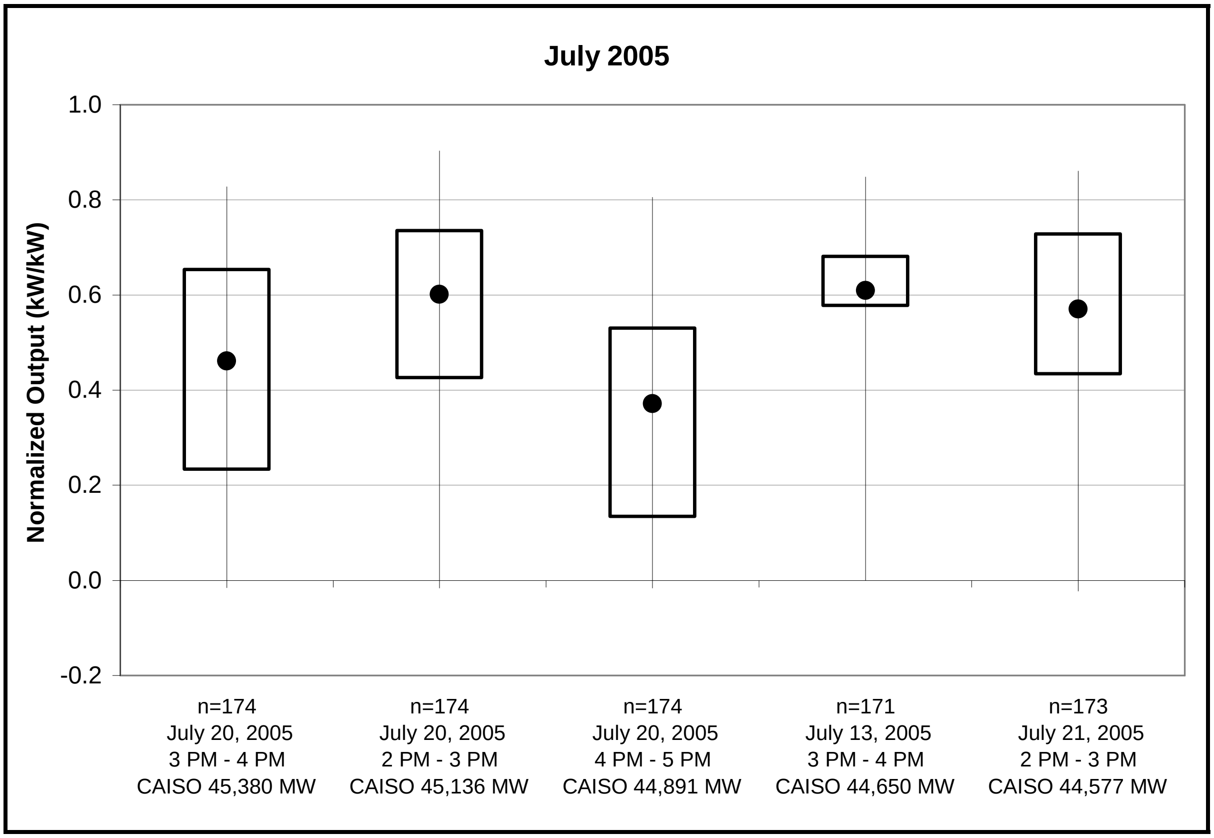


Figure 6–6: PV Demand Impact – Summer (continued)

August 2005 CAISO maximum loads occurred between 3 pm and 5 pm. On four separate days during hour from 3 pm to 4 pm, PV outputs were closely distributed.

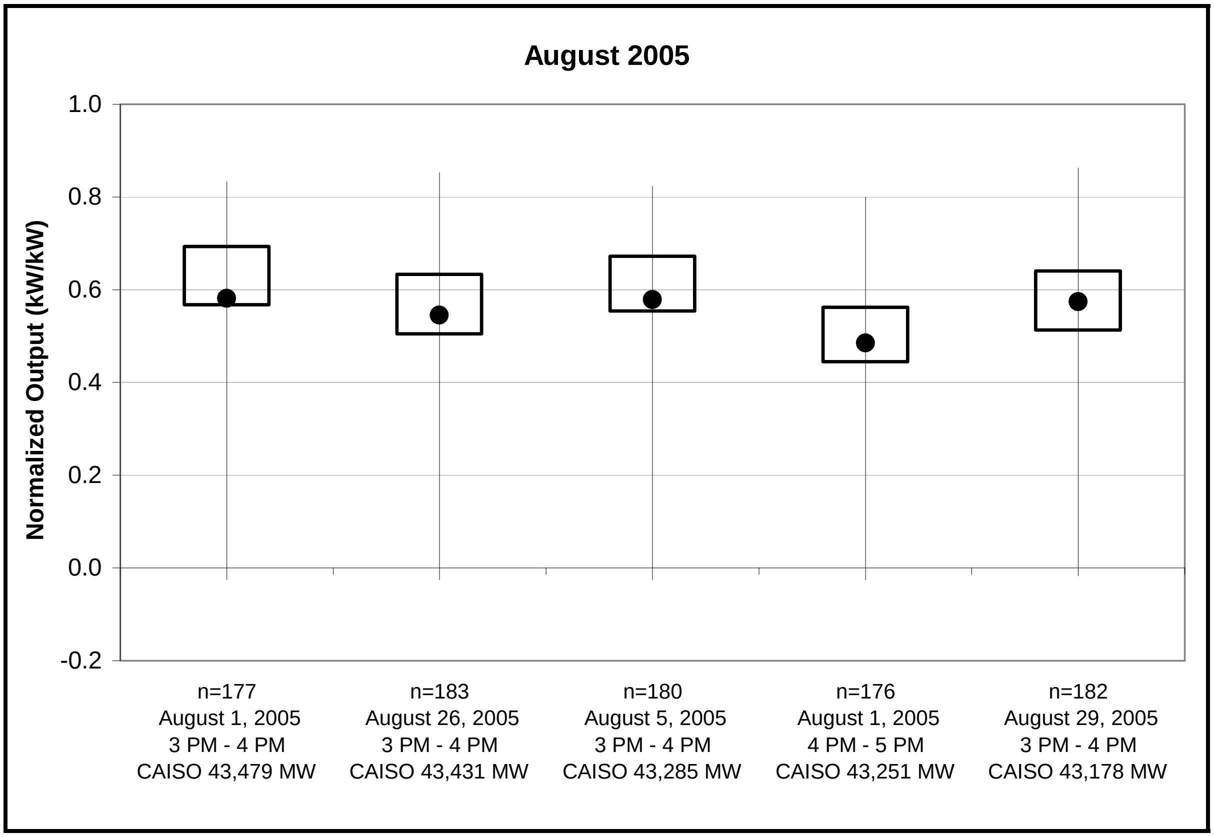


Figure 6-7: PV Demand Impact - Fall

September 2005 CAISO maximum loads occurred between 2 pm and 5 pm. As usual, normalized output was less as the peak hour grew later. The 5 top load hours in this month occurred between just two days.

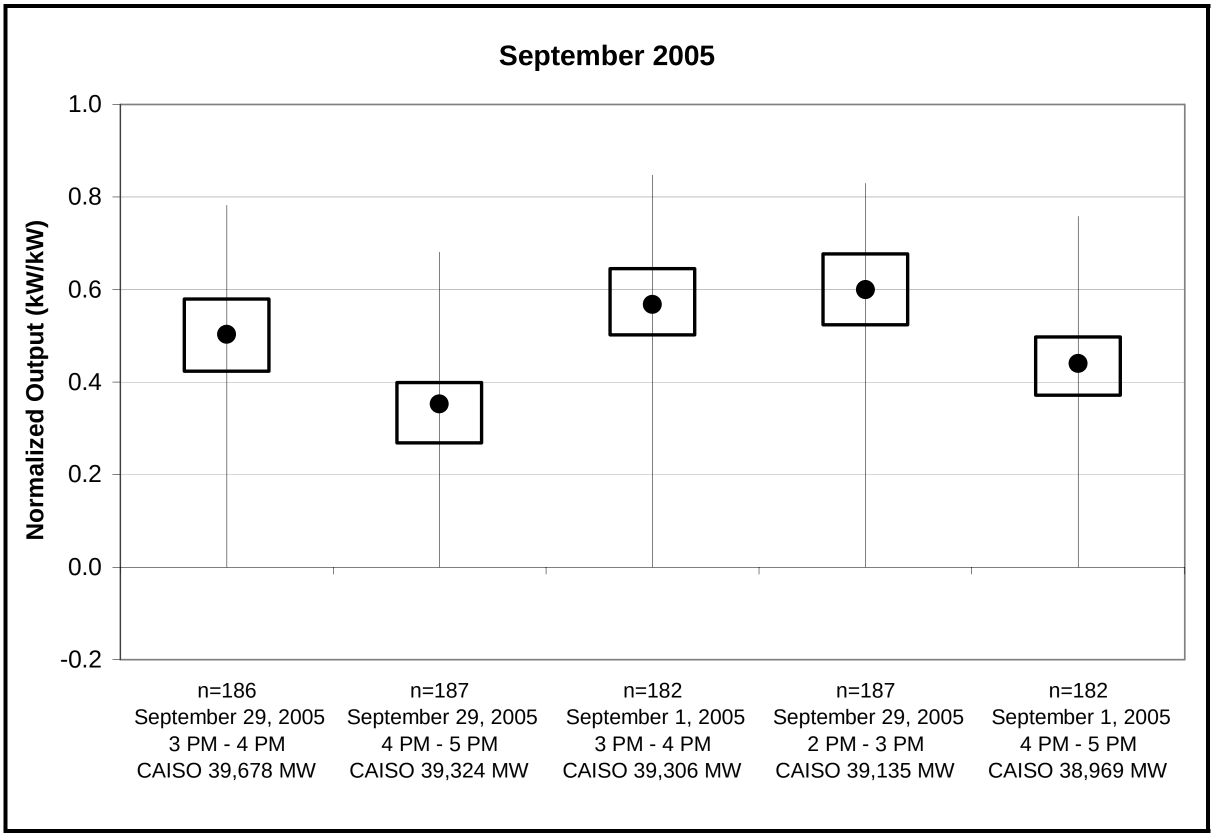


Figure 6–7: PV Demand Impact – Fall (continued)

October 2005 CAISO maximum loads occurred between 1 pm and 4 pm. As before, hours nearer noon had higher output.

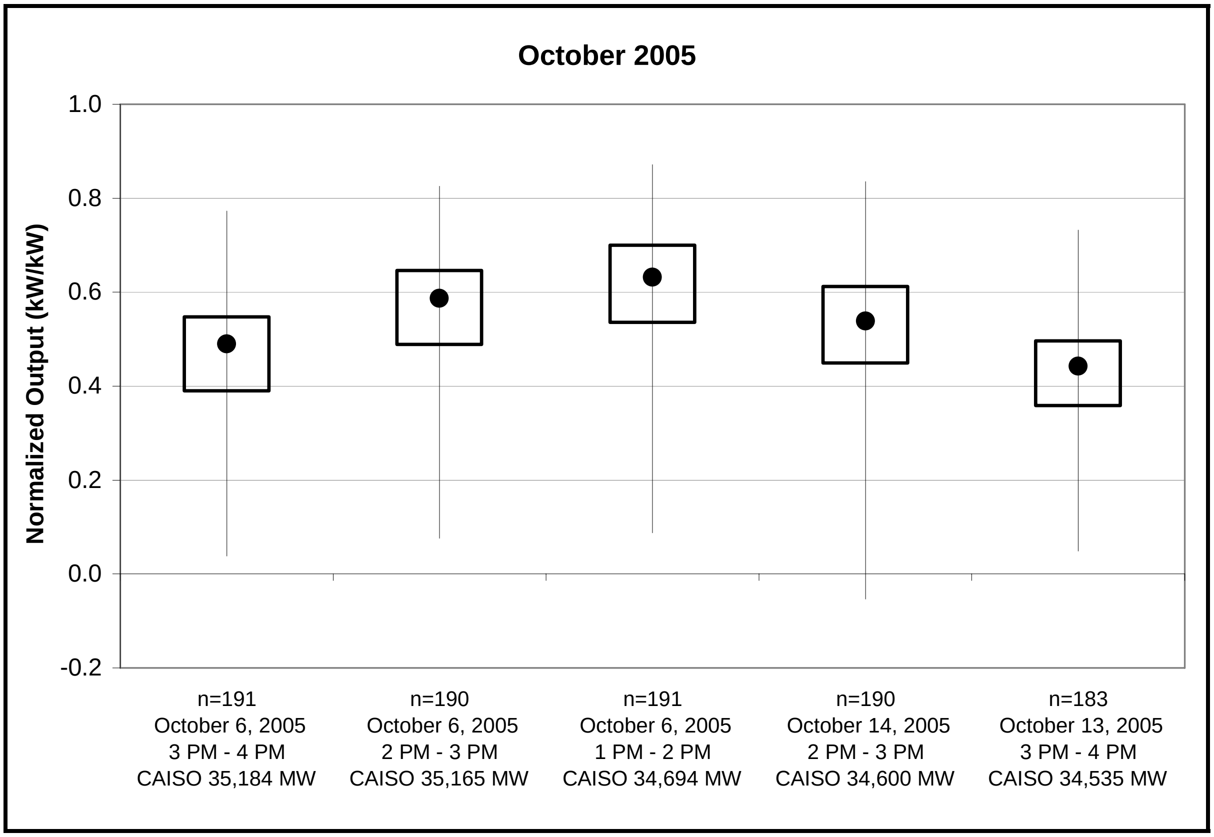
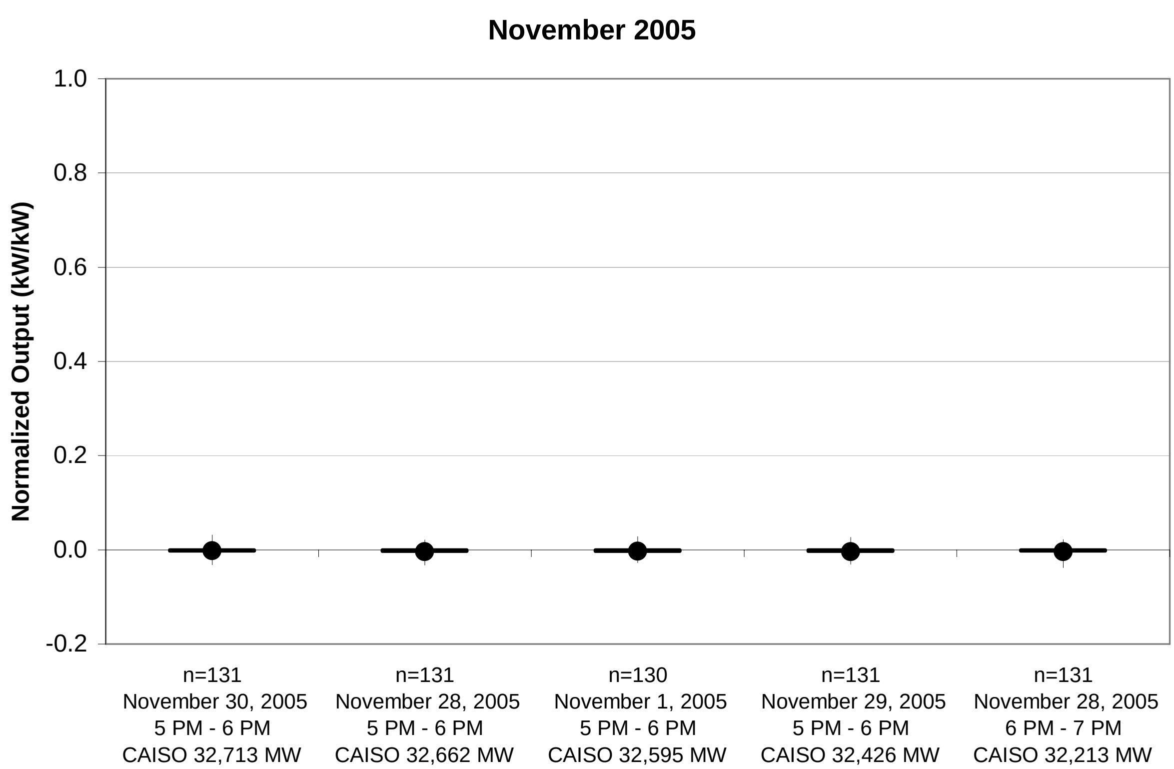


Figure 6–7: PV Demand Impact – Fall (continued)

November 2005 CAISO maximum loads occurred between 5 pm and 7 pm. The 5 top loads occurred between two days. As with March, statewide the sun was setting.



Energy Impact

When metered data were available, they were used directly to calculate energy impacts of PV systems. However, as noted above a substantial portion of total SGIP PV energy production was not captured in interval-metered data. Therefore, energy impacts were estimated in cases where metered data were not available. Metered and estimated energy production (MWh) impact results for Level 1 PV systems are summarized by quarter in Table 6-3.

Table 6-3: Energy Impacts of PV in 2005 by Quarter (MWh)

Output Basis	Q1-2005	Q2-2005	Q3-2005	Q4-2005	Total MWh
Metered	4,800	10,837	11,918	6,786	34,340
Estimated	4,044	9,231	11,529	6,771	31,575
Total	**8,844**	**20,068**	**23,447**	**13,556**	**65,915**

The quarter-to-quarter variability exhibited in energy impact results presented in Table 6-3 is due in part to the fact that Total PV on-line rebated capacity grew by over 70% over the course of the year. The trend is summarized in Figure 6-8 (on the left axis).

The energy production of the combined group of metered PV systems varied according to season. Figure 6-8 illustrates their normalized energy production by month (on the right axis). These values represent the monthly average capacity factor for the on-line PV system capacity.

As expected, normalized energy production levels reach their maximum values in the summer season and decrease towards the winter season. The intensity and duration of incident solar radiation falls off after July, and the incidence of storms and other weather disturbances increases, reducing the availability of solar radiation to PV systems.

Figure 6-8: PV On-Line Capacity & Monthly Average Capacity Factor 2005

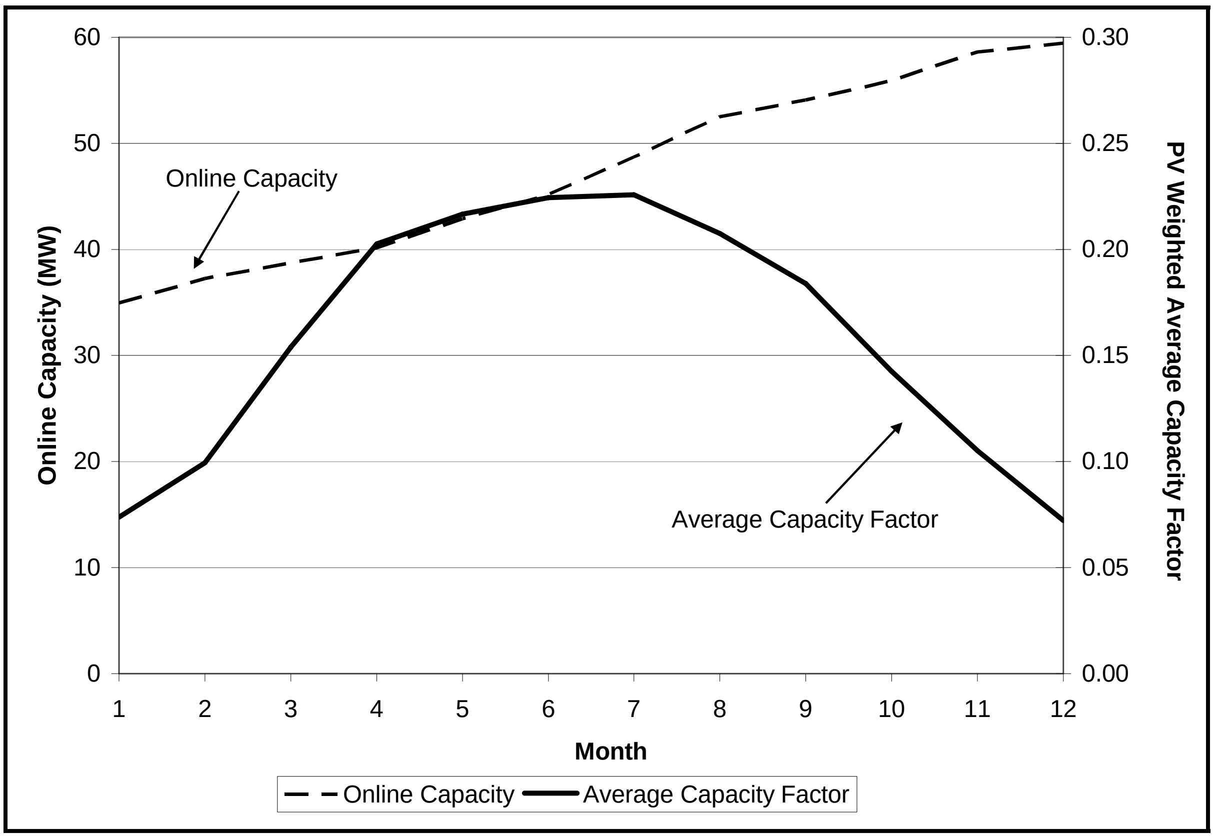


Figure 6-9 illustrates the program-wide trends in monthly weighted average capacity factor. Table 6-4 provides the values plotted in Figure 6-9. The subsequent four figures show capacity factor trends for the IOUs individually. There are no clear trends in capacity factor as the variability of monthly weather from year to year greatly influences the results. So too does the number of PV systems contributing to the result. Larger variability is to be expected in earlier program years when fewer systems are on-line. To describe PV performance trends over time would require careful controlling for actual weather variability. A survey of observed weather data across the state does show that the first quarters of 2003 and 2004 generally had over 5 percent greater cumulative monthly solar radiation than 2005, which may largely explain the tendency for 2005 to have lowest capacity factors in the first quarter.

Figure 6-9: Level 1 PV Weighted Average Capacity Factor Trend

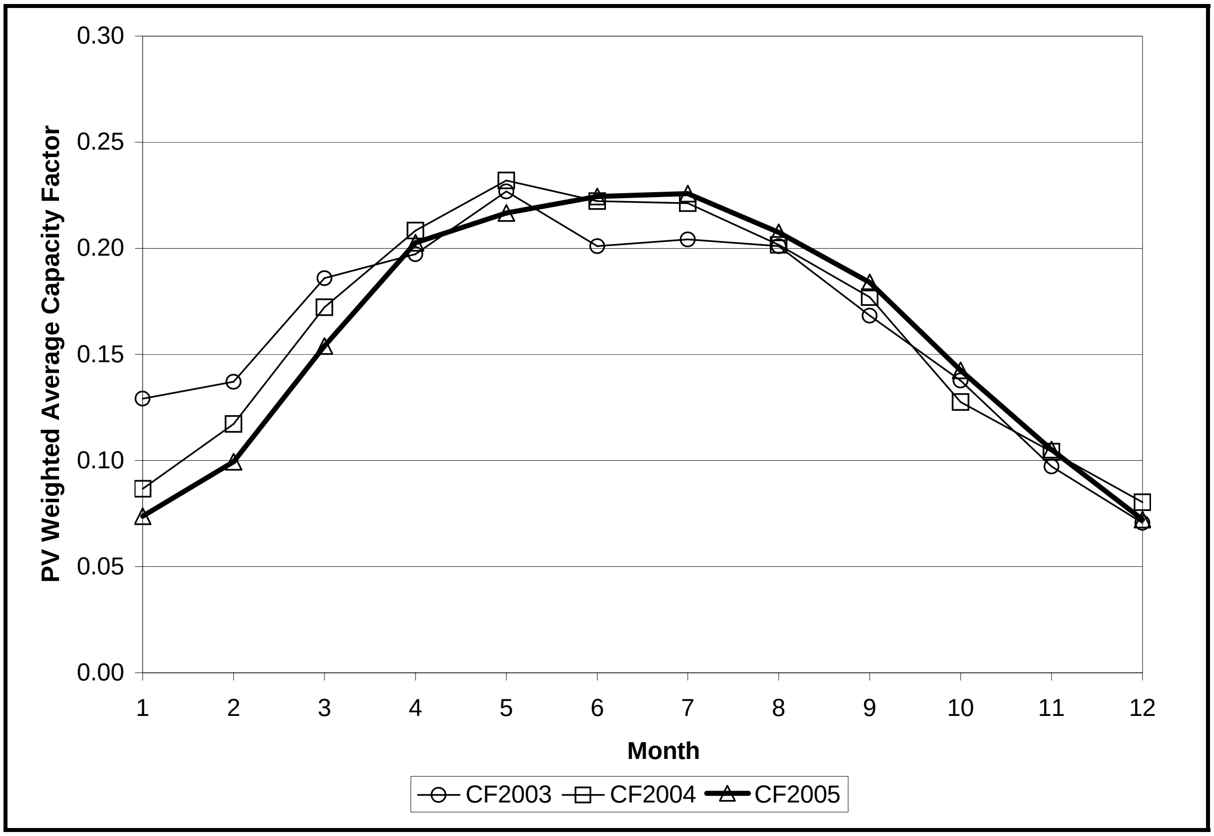


Table 6-4: Level 1 PV Weighted Average Capacity Factor Trend

Month	CF2003	CF2004	CF2005
Jan	0.13	0.09	0.07
Feb	0.14	0.12	0.10
Mar	0.19	0.17	0.15
Apr	0.20	0.21	0.20
May	0.23	0.23	0.22
Jun	0.20	0.22	0.22
Jul	0.20	0.22	0.23
Aug	0.20	0.20	0.21
Sep	0.17	0.18	0.18
Oct	0.14	0.13	0.14
Nov	0.10	0.10	0.11
Dec	0.07	0.08	0.07

Figure 6-10: PG&E's Level 1 PV Weighted Average Capacity Factor Trend

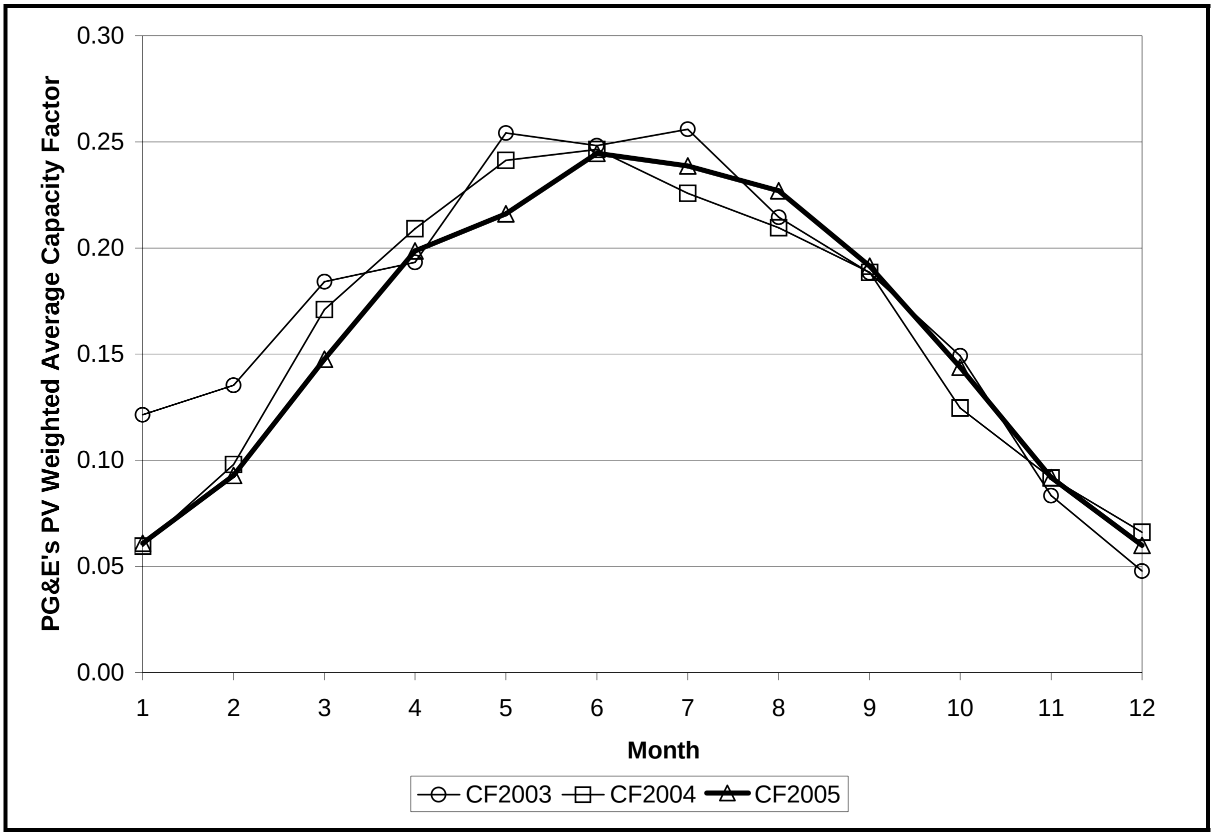


Figure 6-11: SCE's Level 1 PV Weighted Average Capacity Factor Trend

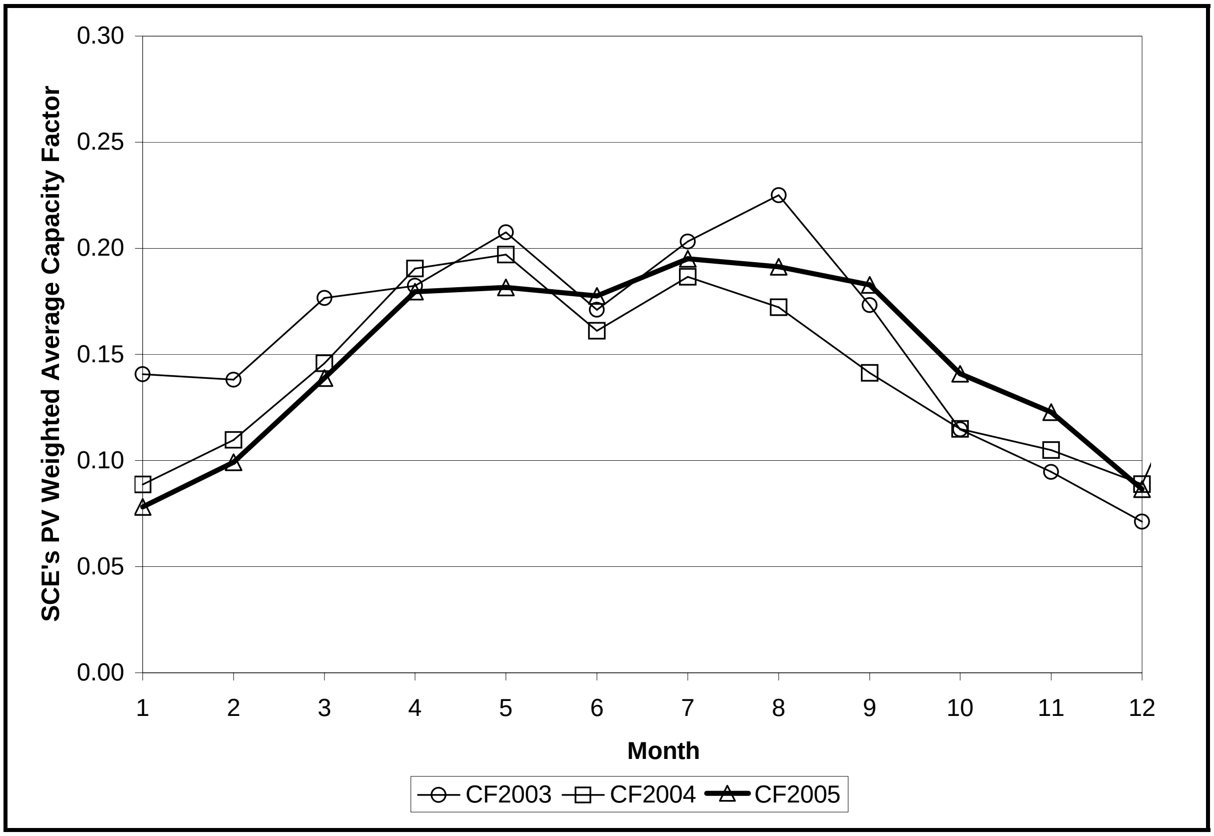


Figure 6-12: SDREO's Level 1 PV Weighted Average Capacity Factor Trend

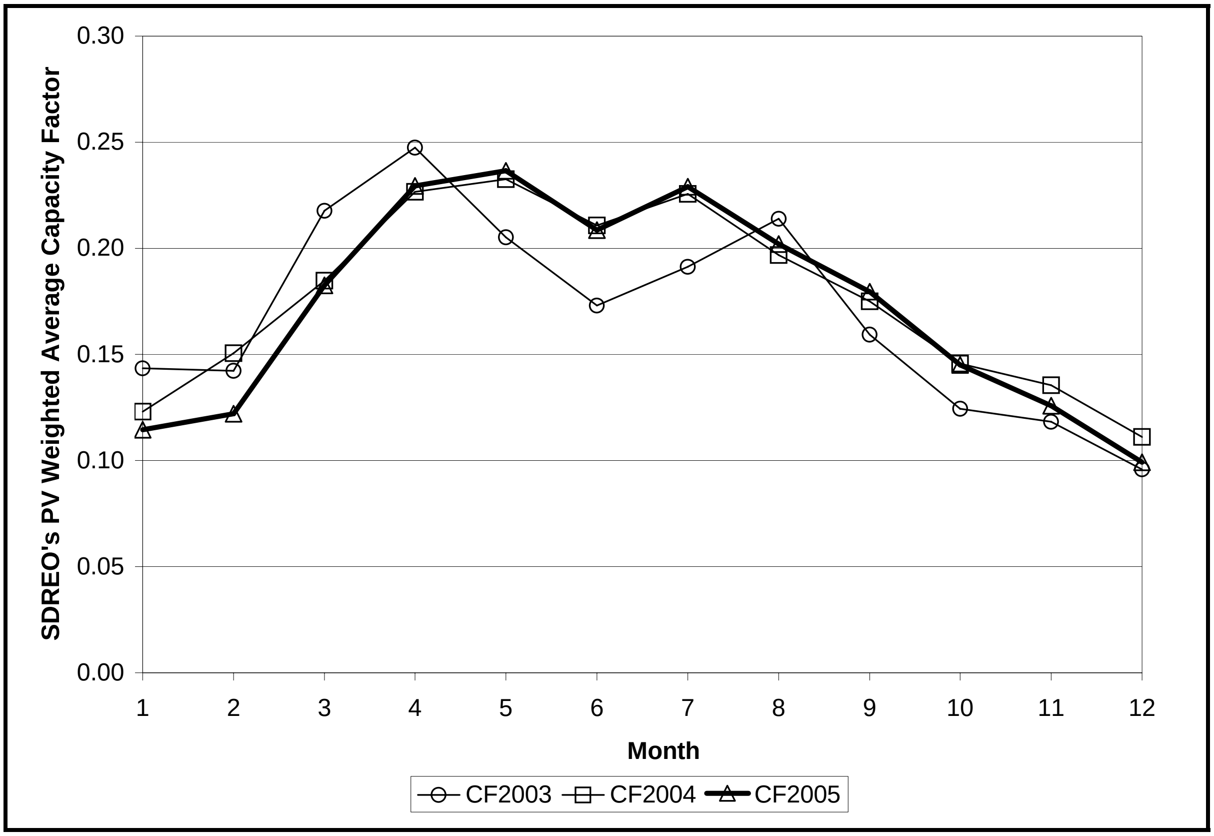
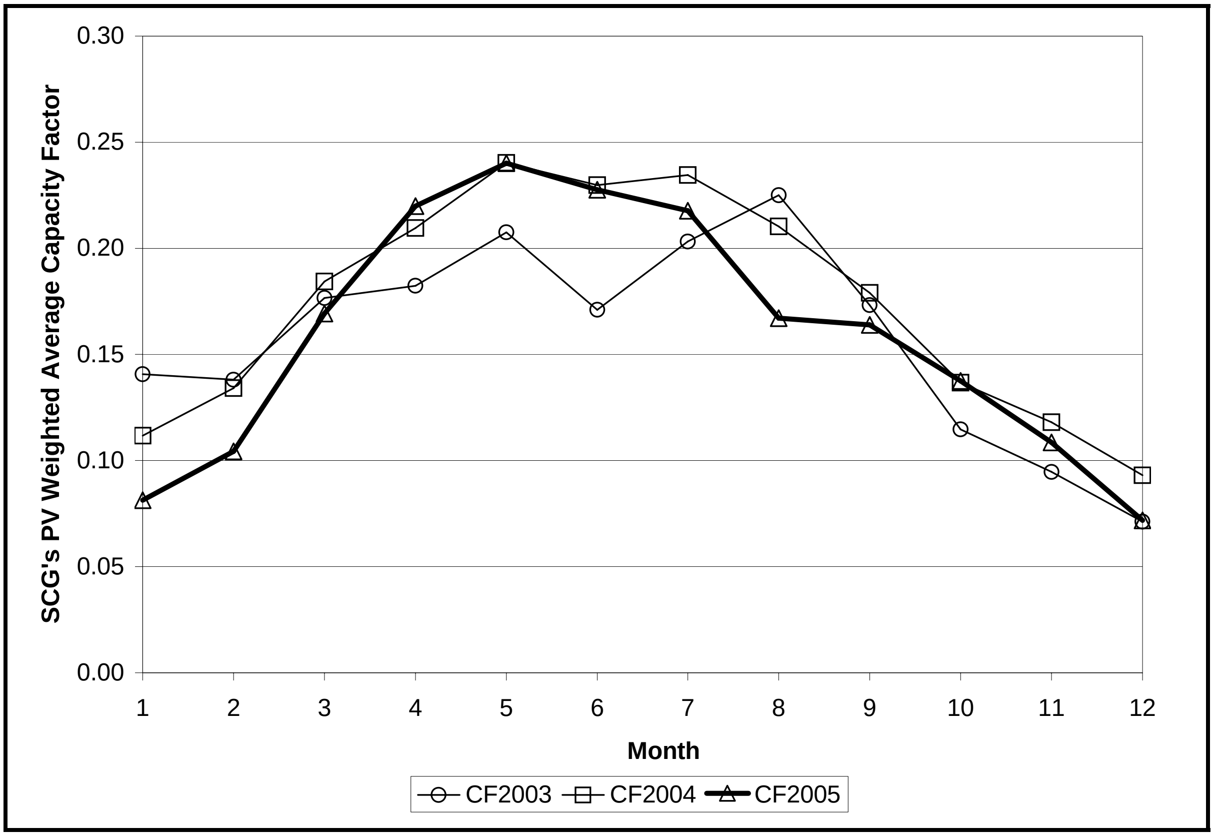


Figure 6-13: SCG's Level 1 PV Weighted Average Capacity Factor Trend



6.3 Level 1 Wind Turbine Systems

There were only two wind turbine systems on-line by the end of 2005. While the first system came on-line in September 2004, the second system was not on-line until June of 2005. Consequently, metered data could only be obtained for one system. Energy delivery and demand impacts were estimated for the system installed later in 2005. Estimates were based on wind speed data from nearby weather stations and scaled to the hub height of the wind turbine.

Table 6-5 provides energy delivery impacts of Level 1 wind turbines during 2005 and Table 6-6 provides information on coincident peak impacts.

Table 6-5: Energy Impact of Level 1 Wind Turbines in 2005 by Quarter (MWh)

Output Basis	Q1-2005	Q2-2005	Q3-2005	Q4-2005	Total MWh
Metered	291	403	366	230	1,290
Estimated	10	300	269	169	748
Total	**301**	**703**	**634**	**400**	**2,038**

Table 6-6: Impact of Level 1 Wind Turbines Coincident with 2005 CAISO Peak

Output Basis	On-Line Systems (n)	On-Line Capacity (kW)	Peak Demand Impact (kW_P)	ISO Peak Ratio ($kW_P/kW_{Rebated}$)
Metered	1	950	651	0.68
Estimated	1	699	255	0.37
Total	**2**	**1,649**	**906**	0.55

6.4 Level 1 & 2 Fuel Cells

As of the end of 2005, two Level 1 fuel cells (renewable fuel) were operational. Estimated 2005 peak demand impacts on the CAISO from the on-line Level 2 fuel cell projects are summarized in Table 6-7. Because of the limited number of systems online in 2005, it is difficult to extrapolate useful information from these results. As more fuel cells come online site-specific issues will have less of an impact on the overall result.

Table 6-7: Impact of Level 1 Fuel Cells Coincident with 2005 CAISO Peak

Basis	On-Line Systems (n)	On-Line Capacity (kW)	Peak Demand Impact (kW_P)	ISO Peak Ratio ($kW_P/kW_{Rebated}$)
Metered	2	750	-54	-0.07
Estimated	0	0	0	0.00
Total	**2**	**750**	**-54**	-0.07

As of the end of 2005, two Level 1 fuel cells (renewable fuel) and six Level 2 fuel cells (nonrenewable fuel) were operational. An average operating capacity factor of 91% for Level 2 systems is indicated by the limited quantity of available metered data. This average value was used to estimate demand and energy impacts of the on-line fuel cell systems during periods when metered data were not available. Estimated 2005 peak demand impacts on the CAISO from the on-line Level 2 fuel cell projects are summarized in Table 6-8.

Table 6-8: Impact of Level 2 Fuel Cells Coincident with 2005 CAISO Peak

Basis	On-Line Systems (n)	On-Line Capacity (kW)	Peak Demand Impact (kW_P)	ISO Peak Ratio ($kW_P/kW_{Rebated}$)
Metered	1	200	196	0.98
Estimated	2	1,600	1,566	0.98
Total	**3**	**1,800**	**1,762**	0.98

The distribution of Level 1 and Level 2 fuel cell energy impact by quarter is summarized in Table 6-9 and Table 6-10.

Table 6-9: Energy Impact of Level 1 Fuel Cells in 2005 by Quarter (MWh)

Output Basis	Q1-2004	Q2-2004	Q3-2004	Q4-2004	Total MWh
Metered	632	922	401	678	2,634
Estimated	0	0	0	3	3
Total	**632**	**923**	**401**	**682**	**2,637**

Table 6-10: Energy Impact of Level 2 Fuel Cells in 2005 by Quarter (MWh)

Output Basis	Q1-2004	Q2-2004	Q3-2004	Q4-2004	Total MWh
Metered	421	396	360	613	1,790
Estimated	1,265	1,593	3,524	2,993	9,374
Total	**1,686**	**1,989**	**3,884**	**3,606**	**11,164**

6.5 Level 3/3-N/3-R: Microturbines, IC Engines, and Small Gas Turbines

Consistent with the other technologies, data from metered projects were used to estimate impacts of unmetered internal combustion engines, microturbines, and small gas turbines. Available metered data were used to calculate ratios representing average power output per unit of rebated system capacity. For periods when no metered data were available, estimates of power output were calculated as:

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

Where:

$EN\hat{G}O_{psdh}$ = Predicted net generator output for project *p* in strata *s* on day *d* during hour *h*

Units: kWh
Source: Calculated

S_{ps} = System size for project *p* in strata *s*[2]

Units: kW
Source: SGIP Tracking System

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

Units: kWh
Source: Net Generator Output Meters

[2] Strata for cogeneration systems include incentive level and technology type

Some SGIP projects satisfy the program's heat recovery requirements by providing recovered heat to an absorption or adsorption chiller that enables elimination or unloading of electric-driven cooling capacity. Indirect electric demand reduction yielded by elimination or unloading of electric chillers is not included in the SGIP impact evaluation results reported in the annual impact evaluation reports.

The issue of so called 'secondary' or indirect electric impact of cooling or other electric process heating equipment was addressed in detail as part of the preliminary cost-effectiveness evaluation[3]. In the cost-effectiveness evaluation, the assessment of equipment not covered directly by the SGIP includes incremental electric impact as well as incremental project cost. Both are governed by baseline assumptions underlying the analysis.

Demand Impact Coincident with CAISO Peak

On July 20, the day of CASIO system peak demand, there were 217 engines and turbines installed and on-line under the SGIP. Interval-metered data were available for 102 of these Level 3/3-N/3-R systems. Resulting estimates of peak demand impact on the CAISO are summarized in Table 6-11. The estimated demand impact corresponds to 0.63 kW per 1.00 kW of installed system size (basis: rebated capacity). The total program-level system peak demand impact for incentive Level 3/3-N/3-R engines and turbines are estimated at 67,536 kW (i.e., approx. 68 MW).

Table 6-11: Impact of Level 3/3-N/3-R Systems Coincident with 2005 CAISO Peak

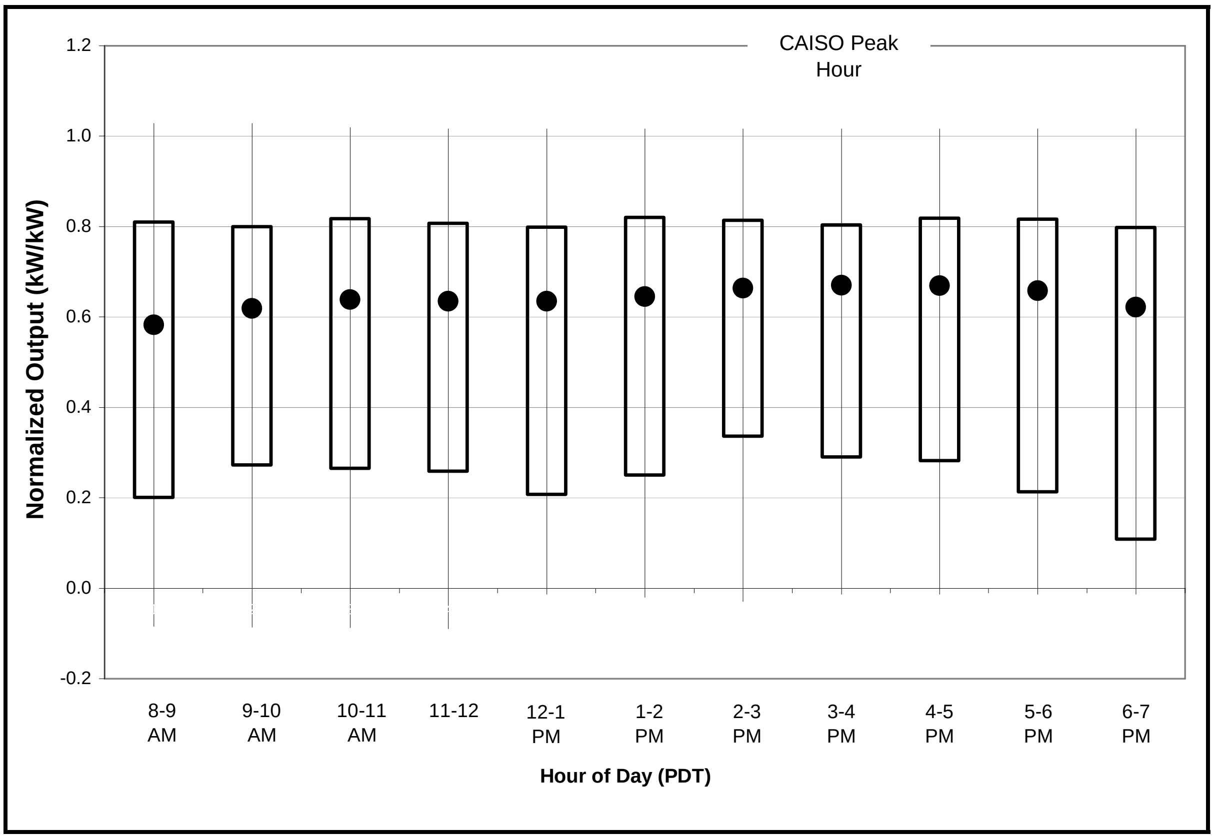
Basis	On-Line Systems (n)	On-Line Capacity (kW)	Peak Demand Impact (kW_P)	ISO Peak Ratio ($kW_P/kW_{Rebated}$)
Metered	102	49,685	33,297	0.67
Estimated	115	57,036	34,240	0.57
Total	**217**	**106,721**	**67,536**	0.63

[3] Itron, "CPUC Self-Generation Incentive Program: Preliminary Cost-Effectiveness Evaluation Report," September 2005

The peak-day operating characteristics of the 102 engine and turbine projects for which peak-day interval-metered data were available are summarized in the box plot of Figure 6-14. System sizes were used to normalize power output values prior to plotting summary statistics of electric output profiles for individual projects. The normalized values represent power output per unit of system size. Treatment in this manner enables direct comparison of the power output of systems of varying sizes.

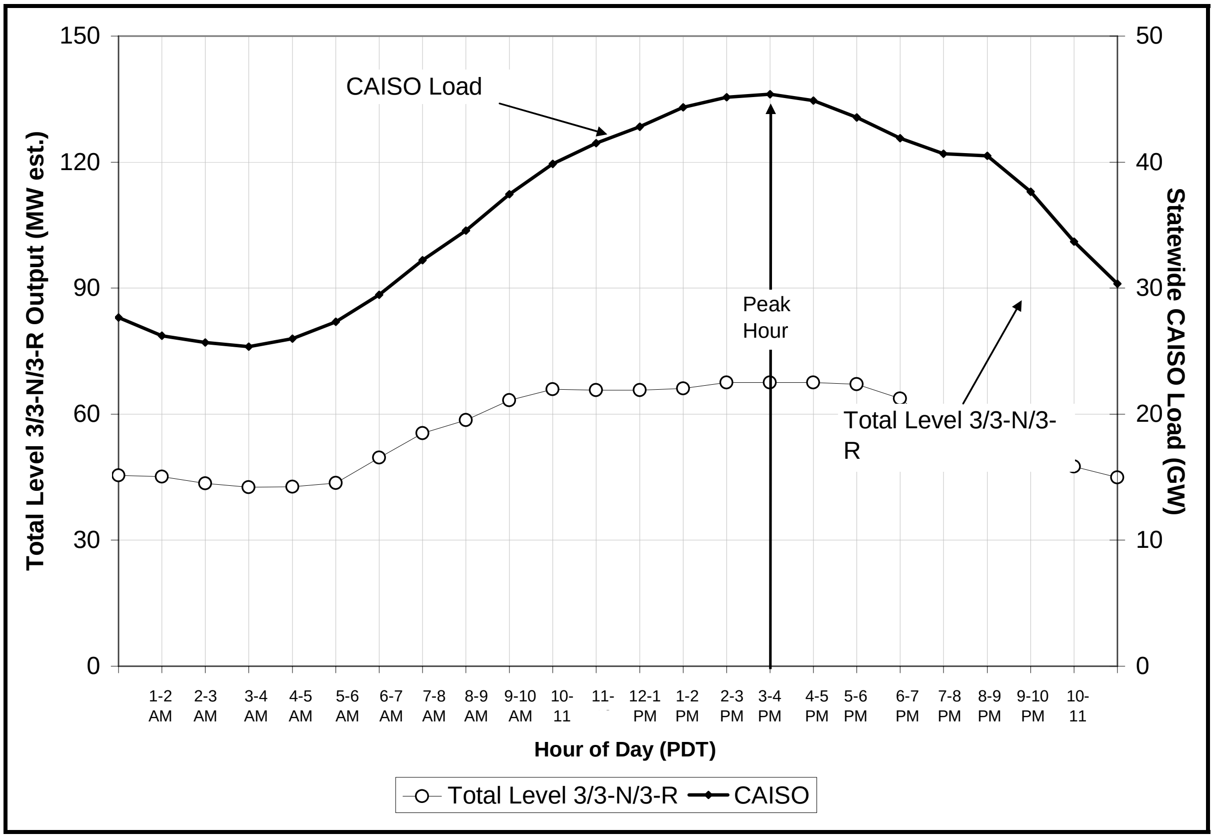
The boxes represent ranges within which 75 percent of project-specific values lie. The vertical lines represent the range of project-specific values (i.e., maximum and minimum normalized output). The weighted averages depicted in this graphic with solid black circles were calculated as the total power output of the 102 systems divided by total cumulative capacity of those systems. These values were used to estimate output of Level 3/3-N/3-R projects in cases where metered data were unavailable. Numerous systems were idle on this CAISO peak day, which explains why the lower edge of the 25th to 75th percentile rectangles are positioned near 0 kW/kW.

Figure 6-14: CAISO Peak Day Level 3/3-N/3-R Output Profile Summary



The peak-day profiles of CAISO system loads and the total of the metered/estimated output of the 217 on-line Level 3/3-N/3-R systems are illustrated in Figure 6-15. The shape of the output curve for engines and turbines aligns well with the CAISO system peak from 3 p.m. to 4 p.m., and the two curves maintain a similar relationship during both diurnal shoulder periods (before and after the peak).

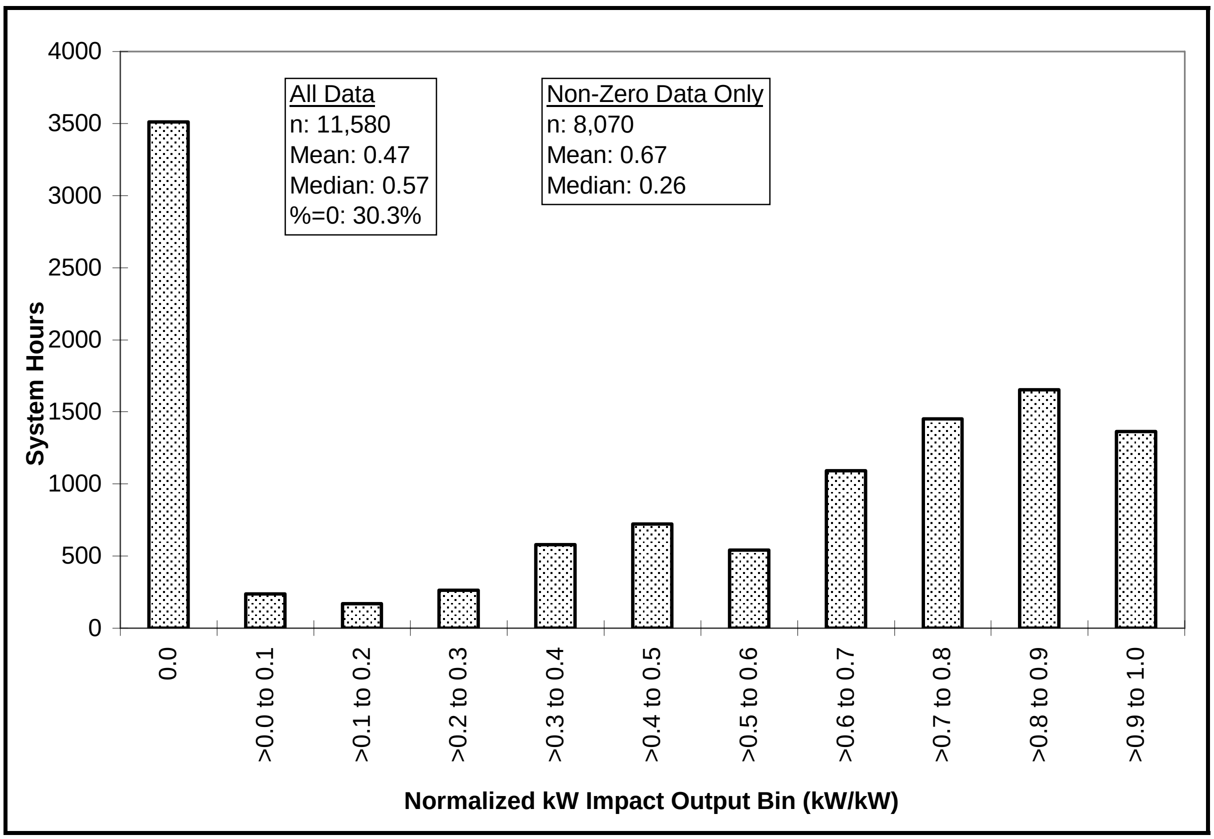
Figure 6-15: CAISO 2005 Peak Day Load & Coincident Total Level 3/3-N/3-R Generation Output



To more completely characterize SGIP demand impacts, normalized hourly output of the metered Level 3/3-N/3-R systems during 2005 coincident with the CAISO maximum loads (i.e., based on the 5 peak hours of each month) are summarized in Figure 6-16. Each "System Hour" represents a 60-minute period during which a system was "on-line". In some instances systems were on-line but not operational. Such idle systems influence the weighted average demand impact of the SGIP systems.

Whereas for PV both intra- and inter-day variability were significant, for Level 3/3-N/3-R systems it was more meaningful to consider all 60 CAISO-maximum load hours as a single group. These 60 hours correspond to a total of 11,580 system hours (i.e., the average number of "on-line" but not necessarily operational systems was 193). As discussed previously, on-line capacity increased steadily throughout 2005. For this group, normalized kW output of the monitored systems averaged 0.47 kW of power output per kW of rebated system size during the top 5 peak load hours of each month over the CY05 period of this assessment. This annual average result is similar to the weighted average demand impact of metered systems during the single hour of the CAISO annual peak (0.63 kW/kW).

Figure 6-16: Demand Impact – Level 3/3-N/3-R
Basis: Five Hours each Month when CAISO Loads Reach Maximum Levels



The idle units (0.0 kW/kW normalized output) play an important role in reducing the average output of all rebated units during hours when CAISO loads reach their maximum values. The average output of operational projects (0.67 kW/kW) is 43% higher than the average for the entire group (including idle systems). Several characteristics of the idle-system hours include:

- Many rebated systems comprise multiple generating units. For instance, for a system comprising two units, normalized output equal to 0.5 kW/kW could represent full-load operation of one unit only, or half-load operation of both units. In many instances electric metering captures output of all rebated units, thus limiting ability to infer operational practices directly from the data.
- Cogeneration systems may be operated in a "load following" mode. Depending on the size of the cogeneration system relative to the magnitude and timing of facility loads, a system which is load following may at times show reduced output levels. The influence of these factors on energy production is discussed in the following section.

Energy Impact

When metered data were available, they were used directly to calculate energy impacts of Level 3/3-N/3-R systems. Energy impacts were estimated in cases where metered data were not available. The resulting distribution of energy impacts by quarter is summarized in Table 6-12.[4] The variability in energy production observed across quarters is partially attributable to systems coming on-line throughout 2005. Fuel price variability is another factor influencing energy impact. The issue of fuel price versus electricity price (i.e., "spark gap") has been discussed in detail in the 2004 Impacts Report. In general, spark gap represents a situation wherein natural gas prices were rising much more rapidly than the commensurate retail rate electricity prices. As a result, owners of cogeneration systems found it uneconomic to operate their facilities and would reduce or altogether shut down their cogeneration facilities.

Table 6-12: 2005 Energy Impacts of Level 3/3-N/3-R Systems by Quarter (MWh)

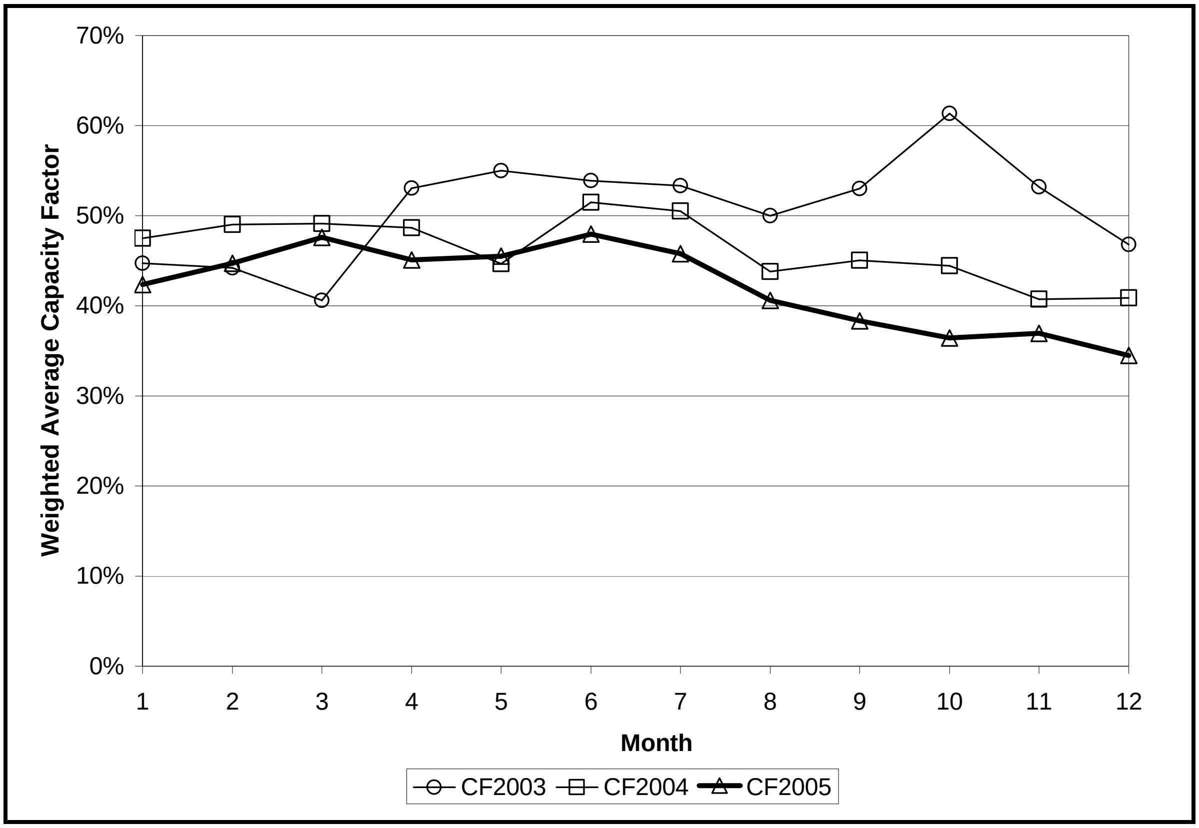
	Q1-2005	Q2-2005	Q3-2005	Q4-2005	Total
Basis	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
Metered	35,613	44,748	57,023	51,472	188,856
Estimated	56,761	60,694	47,055	46,128	210,639

[4] The ratio of metered to estimated energy impacts is higher than the ratio of metered to estimated demand impact because monthly fuel usage and monthly generator electric energy production data were used in the assessment of energy impact. The analysis of electric demand impact was limited to systems where interval-metered electric power output data were available.

The monthly average capacity factor trend for Level 3/3-N/3-R systems is summarized in Figure 6-17 along with monthly average capacity factor. Whereas for PV systems the pronounced seasonal variability of monthly average capacity factor illustrated in Figure 6-9 was expected, the capacity factor of engines and turbines is influenced by fundamentally different factors. PV system power output is primarily governed by weather, and PV systems in the program are eligible for net-metering tariffs that enable them to produce more power than is consumed by the facility during certain hours.

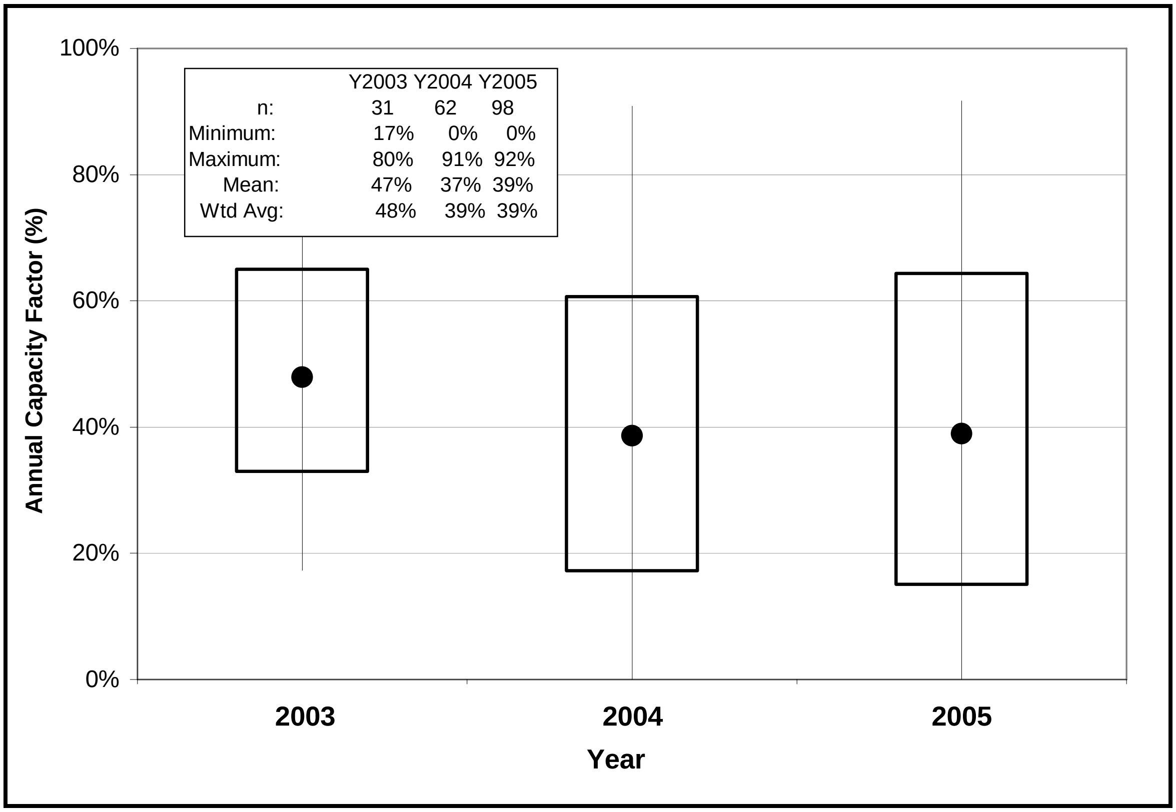
Engine and turbine power output is primarily governed by on/off switches and the on-site demand for thermal energy, and is generally required to be controlled to a level such that substantial quantities of power are not exported to the grid. Depending on the relative size of the engine or microturbine system, when facility power requirements are low the power output of the DG system might need to be throttled down to prevent export of power to the grid. Consequently, monthly average capacity factor may be strongly influenced by facility operating hours (i.e., 1-, 2-, or 3-shift). The capacity factor data presented in Figure 6-17 are provided for summary purposes only. Because additional metered systems were being added periodically throughout the year, and the number of complete-year datasets is small, it is not possible to draw any sweeping conclusions from these summary data. They do provide a meaningful reference point for comparison to capacity factors for other technologies, however.

Figure 6-17: Level 3/3-N/3-R Average Capacity Factor Trend



Generator electric energy production data for 2003 through 2005 are available for a subset of the 217 Level 3/3-N/3-R projects that had come on-line as of the end of 2005. For these systems, the comparison of capacity factors from 2003 through 2005 is depicted graphically in Figure 6-18. The analysis was limited to those projects where at least six months of data were available for each of the years. These data indicate a downward trend in average capacity factor and an upward trend in inter-site capacity factor variability.

Figure 6-18: Level 3/3-N/3-R Capacity Factor Trend



7

System Monitoring and Operational Data Collection

Data collection activities supporting the fifth-year impacts evaluation are summarized in this section. First the several key types of data sources are presented. This is followed by a description of metered data collection issues and current metered data collection status.

7.1 Overview of Key Data Types

Project Files Maintained by Program Administrators

Administrators provided program evaluators regular updates of their program tracking database files. These files contain information that is essential for planning and implementing data collection activities supporting the impact evaluation. Information of particular importance includes basic project characteristics (e.g., incentive level, technology, size, fuel) and key participant characteristics (e.g., Host and Applicant names[1], addresses, and phone numbers). The program evaluator's initial M&E activities for each project were influenced by the project's technology type, program year, and Program Administrator. The program stage of each project was tracked by the program evaluator, and M&E activities initiated accordingly. Updated SGIP handbooks were used for planning and reference purposes.[2]

Reports from Monitoring Planning and Installation Verification Site Visits

During metering and data collection site visits, the on-site evaluation subcontractor[3], collected facility information necessary to complete the project-specific metering and data collection plan in support of the impact evaluation. Meter nameplate information was recorded for meters used for billing purposes, as well as those used for information purposes. The date the system entered normal operations was also determined (or estimated) from the

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

[2] SGIP Handbooks are available on Program Administrator Web sites.

[3] Brown,Vence & Associates, Inc. (BVA), subcontractor to the program evaluator during 2005.

available operations data, as required. Information collected by the on-site evaluator for Program M&E purposes augmented that developed by the Program Administrators' installation verification site inspectors. Inspection Reports produced by these independent consultants were provided to the program evaluator regularly, and their review contributed significantly to the project-level M&E planning efforts.

Metered Performance Data

Electric Net Generator Output (ENGO)

ENGO data collection activities for the fifth-year impact evaluation were aimed at obtaining available data from Hosts, Applicants, electric utilities, and metering installed by the evaluation contractor. One issue affecting collection of electric data concerns the relationship between meter type and project type. Some electric utilities may install different types of ENGO metering depending on project type. In 2005 this was encountered with some cogeneration systems installed in schools, as well as with some Level 3-R projects that are eligible for net metering. The evaluation contractor is working with the affected program administrators and electric utility companies on a plan to have these types of projects equipped with interval recording electric metering in the future.

Useful Thermal Energy

Useful thermal energy data collection typically involves an invasive installation of monitoring equipment (i.e., flow meters and temperature sensors). Many third parties or Hosts had this equipment installed at the time of system installation, either as part of their contractual agreement with a third party vendor or for internal process/energy monitoring purposes. In numerous cases the program evaluation contractor was able to obtain the relevant data these Hosts and third parties were already collecting. This approach was pursued initially in an effort to minimize both the cost- and disruption-related risks of installing monitoring equipment. The majority of useful thermal energy data for 2003-2004 were obtained in this manner.

The statewide evaluation contractor installed useful thermal energy metering for systems that were included in the sample but for which data from existing metering were not available. This meter installation activity began in summer 2003. The first nine useful thermal energy meters were installed by December 2003. Metering installation was put on hold for more than six months (late-fall 2003 - summer 2004) while the several contractual arrangements underlying the work were revised to extend its term. Installation of metering systems resumed in fall 2004 and continued through 2005.

As the data collection effort grew it became clear that the strategy of reliance on data from existing metering needed to be modified. In numerous instances agreements and plans concerning these data did not translate into validated data records available for analysis. Uninterrupted collection and validation of reliable metered performance data is labor- and expertise-intensive. Reliance on data collected by SGIP Host customers and third-parties created schedule and other risks that more than outweighed the benefits that led to the initial strategy. For this reason future useful thermal energy data collection plans will include reduced reliance on data from outside sources. They will still be used, but only when they are very readily available.

Installation of invasive heat metering also involves challenges that significantly limit obtaining heat metered data. Invasive metering techniques can involve temporary shutdown of a project, with a commensurate loss in energy and revenue. Consequently, many SGIP sites were reluctant to allow installation of the heat metering equipment. This reluctance often surfaced in the form of schedule delays. Less invasive heat metering approaches were attempted (e.g., using a "hot tap" to introduce flow metering and temperature sensors into hot water pipes), but also resulted in delays due to the few number of subcontractors that conduct this type of work. The end result was a large gap between the amount of heat data needed for analysis versus the amount of heat data actually obtained. For these reasons, the evaluation contractor elected in 2005 to move completely to non-invasive methods for installation and monitoring of heat data.

Fuel Usage

Fuel usage data collection activities completed to date have involved natural gas monitoring. In the future it may also be necessary to monitor consumption of gaseous renewable fuel to assess compliance with renewable fuel usage requirements in place for Level 1 fuel cell and Level 3-R engine/turbine projects. Prior to 2005 all such on-line projects had utilized only 100% renewable fuel. During 2005 two such projects utilizing both renewable fuel and natural gas came on-line. Current plans call for use of electric output and natural gas usage data to estimate renewable fuel usage (and hence compliance with the program's renewable fuel usage provisions). If initial results of this analysis indicate the project's compliance status is borderline then renewable fuel usage metering may be recommended.

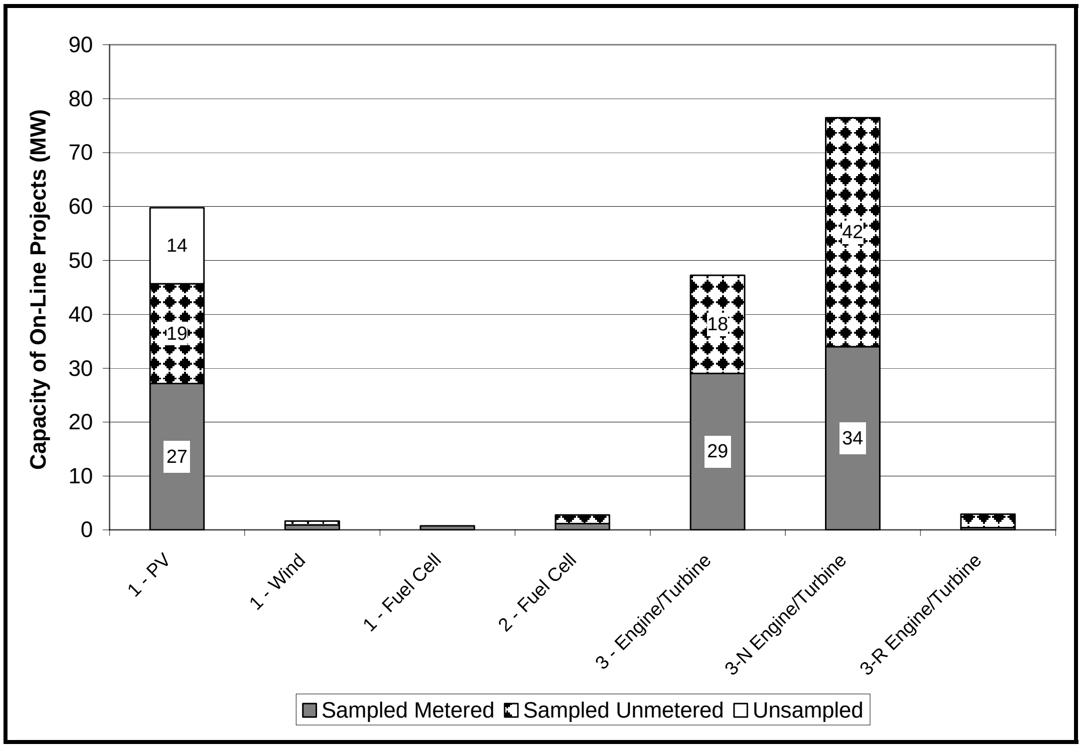
The natural gas usage data used in the fifth-year impacts evaluation were obtained from natural gas utilities, SGIP participants, and natural gas metering installed by the program evaluation contractor. The data were reviewed and their bases documented prior to processing into a data warehouse. Reviews of data validity included combining fuel usage data with power output data to check for reasonableness of gross engine/turbine electrical conversion efficiency. In cases where validity checks were failed the data provider was contacted to further refine the basis of data. In some cases it was determined that data received were for a facility-level meter rather than from metering dedicated to the SGIP cogeneration system. These data were excluded from the impacts analysis.

7.2 Metered Performance Data Collection Status Summary

As of the end of 2005, 784 PY01-PY05 SGIP projects were determined to be on-line. These projects correspond to 192 MW of SGIP project capacity. It is necessary to collect metered data from a certain portion of on-line projects to support the impact evaluation analysis. This section presents summaries of actual data collection based on availability of metered data in December 2005.

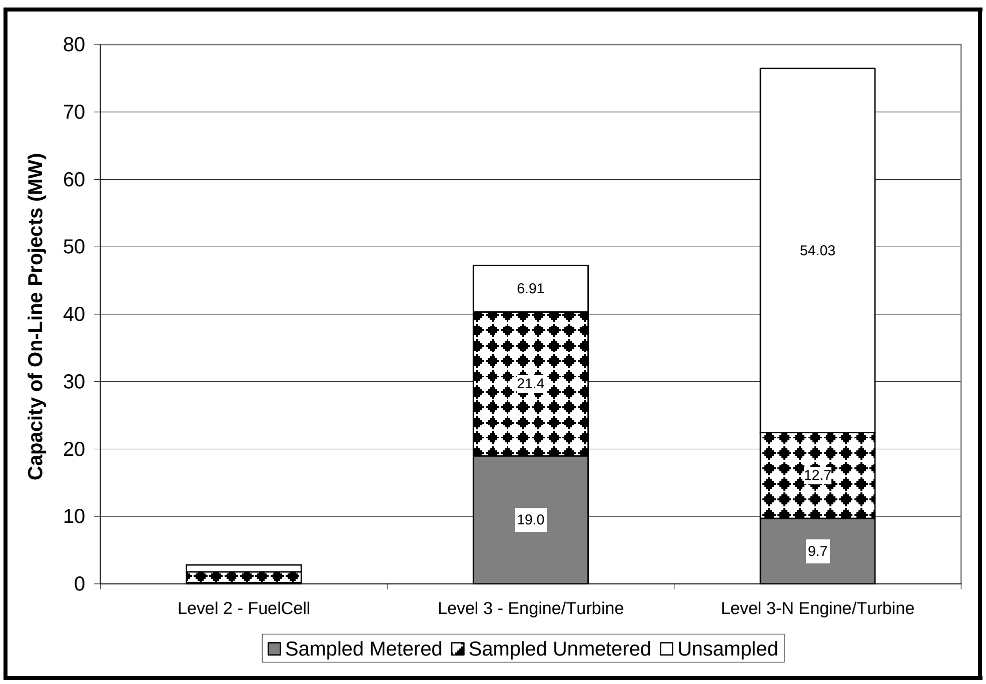
The status of ENGO data collection is summarized in Figure 7-1. A substantial quantity of ENGO metering installation activity remains to be completed. This activity is ongoing and is being carried out by the Program Administrators and the SGIP evaluation contractor. To date PV is the only technology for which some on-line capacity is unsampled. This group of projects includes PY03-PY05 projects smaller than 300 kW for which ENGO data are not available from existing metering. Of principal concern is Sampled-Unmetered capacity corresponding to technologies with small numbers of projects. It is worthy of note that the metering plan in place during 2005 that called for electric metering for all Level 3 and Level 3-N projects was based not on impacts evaluation accuracy criteria, but simply on the expectation that electric utility companies would be monitoring all of these systems for tariff purposes. The highest priority for 2006 is installation of additional ENGO metering for Wind, Fuel Cell, and Level 3-R systems.

Figure 7-1: ENGO Data Collection as of 12/31/2005



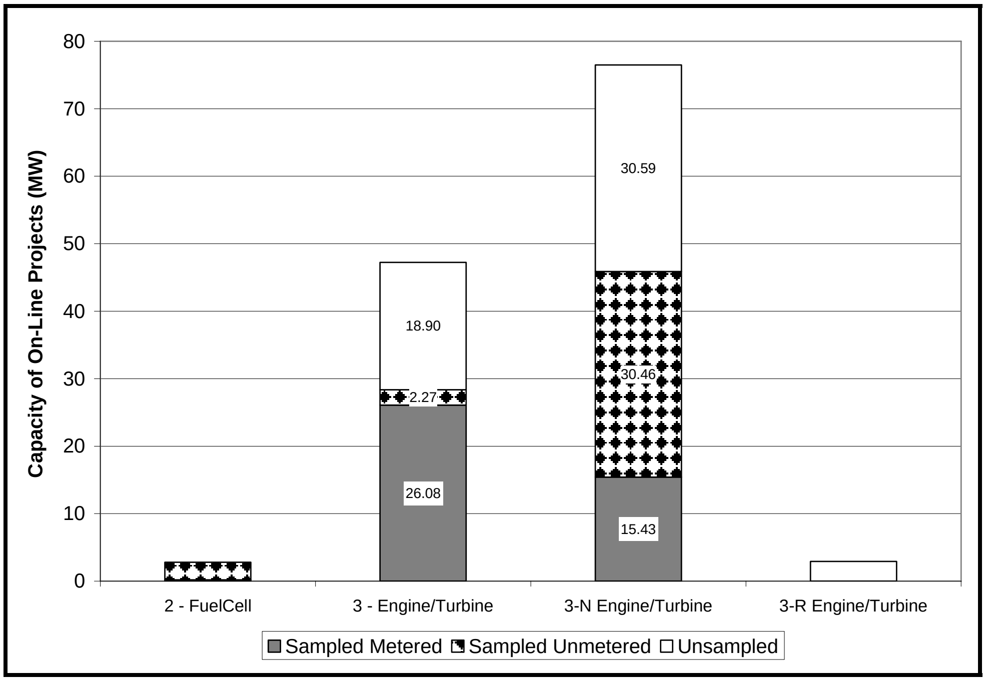
The status of HEAT data collection is summarized in Figure 7-2.

Figure 7-2: HEAT Data Collection as of 12/31/2005



The status of FUEL data collection is summarized in Figure 7-3. Most of the FUEL data have been obtained from IOUs. A principal use of these data is to support calculation of electrical conversion efficiencies and cogeneration system efficiencies.

Figure 7-3: FUEL Data Collection as of 12/31/2005



8

Uncertainty Analysis for Impact Estimates

Program impact estimates were presented in Section 5. In several instances the uncertainty in those estimates was characterized. The bases of those impact estimates uncertainty characterizations are discussed in this section. The scope of the uncertainty analysis includes both measurement error and sampling error.

8.1 Introduction

Impact estimates reported in Section 5 are affected by at least two sources of error that introduce uncertainty into the estimates. The two sources of error are measurement error and sampling error. Measurement error refers to the differences between actual values (e.g., actual electricity production) and measured values (i.e., electricity production values recorded by metering and data collection systems).

Sampling error refers to differences between actual values and values estimated for unmetered systems. The estimated impacts calculated for unmetered systems are based on the assumption that performance of unmetered systems is identical to the average performance exhibited by groups of similar metered projects. Very generally, the *central tendency* (i.e., an average) of metered systems is used as a proxy for the central tendency of unmetered systems.

The actual performance of unmetered systems is not known, and will never be known. It is therefore not possible to directly assess the validity of the assumption regarding identical central tendencies. However, it is possible to examine this issue indirectly by incorporating information about the performance *variability* characteristics of the systems.

Theoretical and empirical approaches exist to assess uncertainty effects attributable to both measurement and sampling error. Propagation of error equations are a representative example of theoretical approaches. Empirical approaches to quantification of impact estimate uncertainty are not grounded on equations derived from theory. Instead, information about factors contributing to uncertainty is used to create large numbers of possible sets of actual values for unmetered systems. Characteristics of the sets of simulated actual values are analyzed. Inferences about the uncertainty in impact estimates are based on results of this analysis.

For this impact evaluation an empirical approach known as Monte Carlo Simulation (MCS) analysis was used to quantify impact estimates uncertainty. The term MCS refers to "the use of random sampling techniques and often the use of computer simulation to obtain approximate solutions to mathematical or physical problems especially in terms of a range of values each of which has a calculated probability of being the solution."[1]

A principle advantage of this approach is that it readily accommodates complex analytic questions. This is an important advantage for this project because numerous factors contribute to variability in impact estimates, and the availability of metered data upon which to base impact estimates is variable. For example, metered electricity production and heat recovery data are both available for some cogeneration systems, whereas other systems may also include metered fuel usage, while still others might have other combinations of data available.

8.2 Data Sources

The usefulness of MCS results rests on the degree to which the factors underlying the simulations of actual performance of unmetered systems resemble factors known to influence those SGIP systems for which impact estimates are being reported. Several key sources of data for these factors are described briefly below.

SGIP Project Information

Basic project identifiers include Program Administrator, project status, project location, system type, and system size. This information is obtained from project lists that Program Administrators update monthly for the CPUC. More detailed project information (e.g., PV system configuration) is obtained from Verification Inspection Reports developed by Program Administrators just prior to issuance of incentive checks.

Metered Data for SGIP DG Systems

Collection and analysis of metered performance data collected from SGIP DG systems is a central focus of the overall program evaluation effort. In the MCS study the metered performance data are used for three principal purposes:

1. Metered data are used to estimate the actual performance of metered systems. The metered data are not used directly for this purpose. Rather, information about measurement error is applied to metered values to estimate actual values.

[1] Webster's dictionary

2. The central tendencies of groups of metered data are used to estimate the actual performance of unmetered systems.
3. The variability characteristics exhibited by groups of metered data contribute to development of distributions used in the MCS study to explore the likelihood that actual performance of unmetered systems deviates by certain amounts from estimates of their performance.

Manufacturer's Technical Specifications

Metering systems are subject to measurement error. The values recorded by metering systems represent very close approximations to actual performance; they are not necessarily identical to actual performance. Technical specifications available for metering systems provide information necessary to characterize the difference between measured values and actual performance.

8.3 Analytic Methodology

The analytic methodology used for this MCS study is described in this section. The discussion is broken down into the five steps listed below:

- Ask Question
- Design Study
- Generate Sample Data
- Calculate the Quantities of Interest for Each Sample
- Analyze Accumulated Quantities of Interest

Ask Question

The first step in the MCS study is to clearly describe the question(s) that the MCS study is being designed to answer. In this instance that question is: How confident can one be that *actual* program total impact deviates from *reported* program total impact by less than certain amounts? The scope of the MCS study includes the following program total impacts:

- Program Total Annual Electrical Energy Impacts
- Program Total Coincident Peak Electrical Demand Impacts
- Program Total PUC218.5(b) Cogeneration System Efficiency

Design Study

The MCS study's design determines requirements for generation of sample data. The process of specifying study design includes making tradeoffs between flexibility and accuracy, and cost. This MCS study's tradeoffs pertain to treatment of the dynamic nature of the SGIP and to treatment of the variable nature of data availability. Some of the systems came on-line during 2005 and therefore contributed to energy impacts for only a portion of the year. Some of the systems for which metered data are available have gaps in the metered data archive that required estimation of impacts for a portion of hours during 2005. These issues are discussed below.

Sample data for each month of the year could be simulated, and then annual electrical energy impacts could be calculated as the sum of monthly impacts. Alternatively, sample energy production data for entire years could be generated. An advantage of the monthly approach is that it accommodates systems that came on-line during 2005 and therefore contributed to energy impacts for only a portion of the year. The disadvantage of using monthly simulations is that this approach is 12 times more labor- and processor-intensive than an annual simulation approach.

A central element of the MCS study involves generation of actual performance values (i.e., sample data) for each simulation run. The method used to generate these values depends on whether or not the system is metered or not. However, for many of the SGIP systems metered data are available for a portion—but not all—of 2005. This complicates any analysis that requires classification of systems as either "metered" or "not metered".

It would be possible to design an MCS study that accommodated the project status and data availability details described above. However, such a study would require considerable resources and would not be likely to yield results that would differ substantially from those yielded by a simpler design. Therefore, two important simplifying assumptions are included in the MCS study design.

1. Each data archive (e.g., electricity, fuel, heat) for each project is classified as being either 'metered' (at least 75 percent of reported impacts are based on metered data) or 'unmetered' (less than 75 percent of reported impacts are based on metered data) for MCS purposes.
2. Only full years of data for unmetered systems are included in the MCS analysis. Projects on-line for fewer than six months are excluded from the analysis. Projects on-line for at least six months are treated as if they were on-line during the entire year.

Generate Sample Data

Actual values for each of the program impact estimates identified above ("Ask Question") are generated for each sample (i.e., "run", or simulation). If metered data are available for the system then the actual values are created by applying a measurement error to the metered values. If metered data are not available for the system then the actual values are created using distributions that reflect performance variability assumptions. **A total of 10,000 simulation runs were used to generate sample data.**

Metered Data Available – Generating Sample Data that Include Measurement Error

The assumed characteristics of random measurement-error variables are summarized in Table 8-1. The ranges are based on typical accuracy specifications from manufacturers of metering equipment (e.g., specified accuracy of +/- 2%). A uniform distribution with mean equal to zero is assumed for all three measurement types. This distribution implies that any error value within the stated range has an identical probability of occurring in any measurement. This distribution is more conservative than some other commonly assumed distributions (e.g., normal "bell shaped" curve) because the outlying values are just as likely to occur as the central values.

Table 8-1: Summary of Random Measurement-Error Variables

Measurement	Range	Mean	Distribution
Electricity	-0.5% to 0.5%		
Natural gas	-2% to 2%	0%	Uniform
Heat recovered	-5% to 5%		

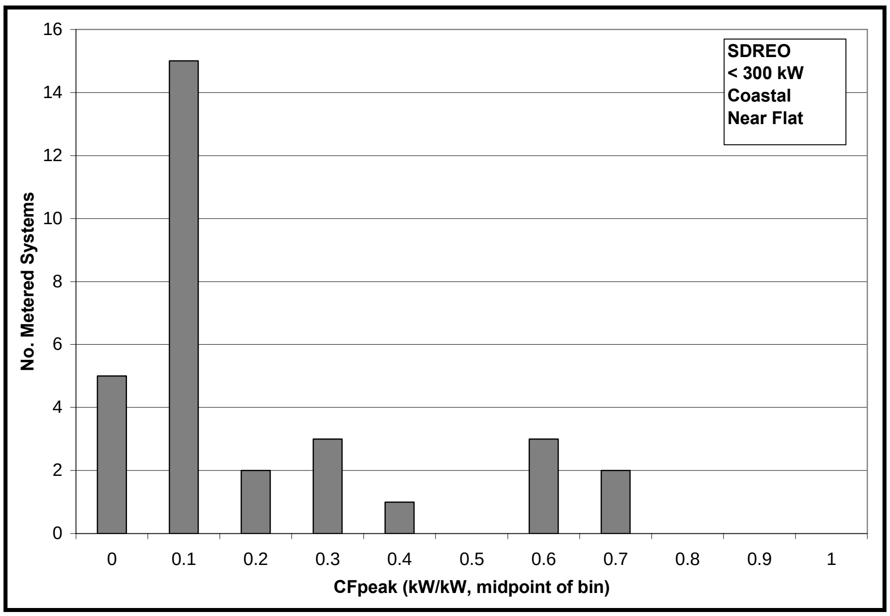
Metered Data Unavailable – Generating Sample Data from Performance Distributions

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

Specification of performance distributions for the MCS study involves a degree of judgment in at least two areas. First, in deciding whether or not metered data available for a strata are sufficient to provide a realistic indication of the distribution of values likely for the unmetered systems. Second, when metered data available for a strata are not sufficient, in deciding when and how to incorporate the metered data available for other strata into a performance distribution for the data-insufficient strata.

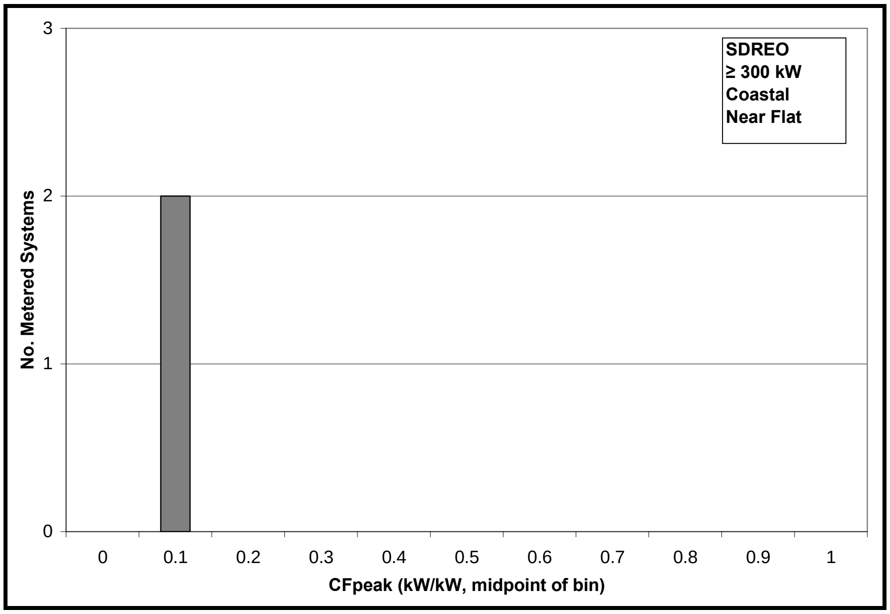
The assessment of the suitability of available metered data for use in MCS performance distributions is illustrated below with an example. The output of a group of SDREO PV systems during the hour when CAISO system load reached its annual peak value is illustrated in Figure 8-1. In this figure PV system output is expressed as metered power output per unit of system rebated capacity (CFpeak). Metered data were available for 31 systems. There were four systems for which metered data were not available for this hour. For each MCS run the actual performance of each of these systems must be assigned from an MCS performance distribution. The metered data available for this group of systems appear to provide a good general indication of the distribution of values likely for unmetered systems.

Figure 8-1: SDREO PV System Measured Coincident Peak Output (Coastal, Near Flat, <300 kW)



There are other sample design strata for which the quantity of metered data available is insufficient to provide a good indication of the distribution of values likely for unmetered projects. For example, if instead of summarizing metered performance of systems <300 kW (Figure 8-1) we graph output of larger (≥300 kW) PV systems we find only two systems. The measured performance of these two systems is summarized in Figure 8-2. If five, or 10, or 31 systems were metered it is unlikely that all of them would occupy the exact same bar in the histogram. The metered data available for this group of systems do not appear to provide a good general indication of the distribution of values likely for unmetered systems.

Figure 8-2: SDREO PV System Measured Coincident Peak Output (Coastal, Near Flat, >300 kW)

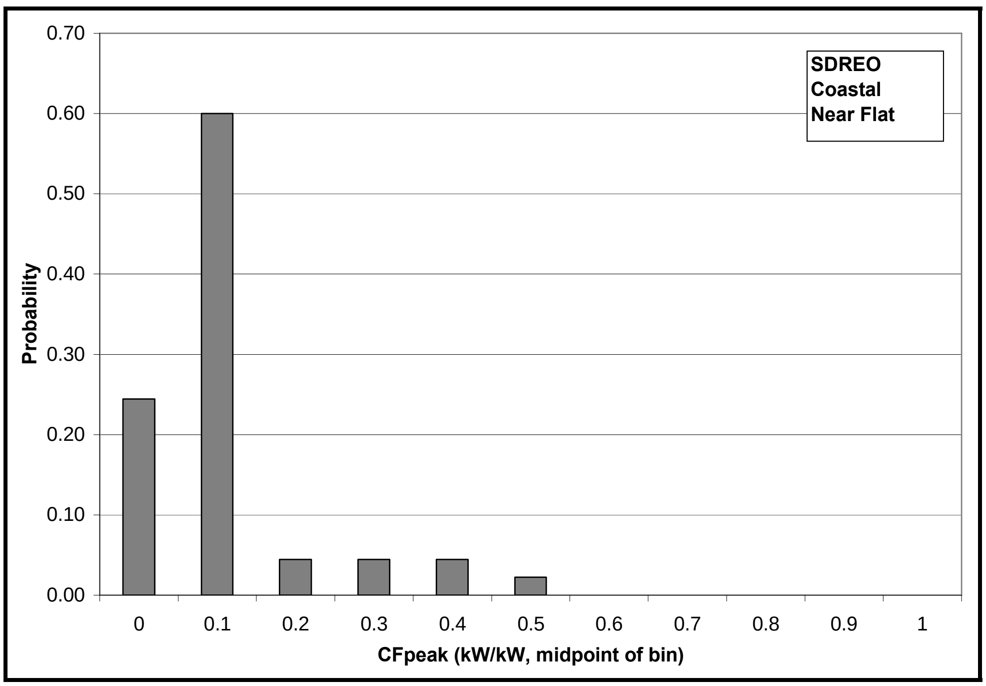


Review of metered data availability for all PV sample design strata revealed numerous instances such as that described above. Consequently, a simplifying assumption was made. System size was dropped as a differentiating factor for purposes of developing MCS performance distributions. For example, a single coincident peak performance distribution was assumed for all of SDREO's near-flat PV systems on the coast. The rationale for this approach rests in part on knowledge of the relative magnitudes of factors influencing PV system performance. Theory and practice both suggest that PV system performance is more sensitive to location and configuration than to system size.

The coincident peak performance distribution assumed for all of SDREO's near-flat PV systems on the coast—regardless of size—is presented in Figure 8-3. Measured performance data available for the metered group of systems sharing these same characteristics provide a good indication of the values likely for unmetered projects. The metered data are not used directly in the MCS, however. The capacity factor values from 0.2 to 0.7 are adjusted.

First, the available data suggest that if more systems were metered some of them would have CFpeak values equal to 0.5. Second, use of a simplified distribution emphasizes the fact that the performance of the unmetered systems is not known, and that in the MCS the assumed distribution of CFpeak values is based on judgment. Lastly, the modification introduces a small measure of additional conservatism into MCS results. In the MCS study a capacity factor is randomly assigned from the performance distribution and sample values are calculated as the product of CFpeak and system size.

Figure 8-3: CFpeak Distribution used in MCS for SDREO PV Systems (Coastal, Near Flat)



A similar approach was used to develop all of the performance distributions used in the MCS. All of these performance distributions are included as Appendix A.

Calculate the Quantities of Interest for Each Sample

After each simulation run the resulting sample data for individual sites are summed to the program level and the result is saved. The quantities of interest were defined previously:

- Program Total Annual Electrical Energy Impacts
- Program Total Coincident Peak Electrical Demand Impacts
- Program Total PUC218.5(b) Cogeneration System Efficiency

Cogeneration system efficiency is a calculated value that is based on sample data for electricity production, fuel consumption, and heat recovery. The efficiency values for each simulation run were calculated as:

$$PUC218.5b_r = \frac{\left(\sum ELEC_{rs} \times \mathrm{KWH2KBTU}\right) + \left(\sum \mathrm{C1} \times HEAT_{rs}\right)}{\sum FUEL_{rs}} \times \frac{100\%}{1}$$

Where:

$PUC218.5b_r$	is program total PUC218.5(b) cogeneration system efficiency for run *r* Units: %
$ELEC_{rs}$	is total electricity production for run *r* and system *s* Units: kWh
KWH2KBTU	is a conversion factor Value: 0.2931 (i.e., 1/3.412) Units: kWh/kBtu
C1	is a constant Value: 0.5 Units: none Basis: Cogeneration system efficiency definition of CPUC
$HEAT_{rs}$	is total useful waste heat recovery for run *r* and system *s* Units: kBtu
$FUEL_{rs}$	is total fuel consumption for run *r* and system *s* Units: kBtu Basis: Lower Heating Value of fuel

Analyze Accumulated Quantities of Interest

The pools of accumulated MCS analysis results are analyzed to yield summary information about their central tendency and variability. Mean values are calculated and the variability exhibited by the values for the many runs is examined to determine confidence levels (under the constraint of constant relative precision), or to determine confidence intervals (under the constraint of constant confidence level).

8.4 Results

Results of the MCS analysis are presented in Table 8-2 to Table 8-4. The presented results are based on a confidence level of 90%[2]. That is, these results indicate that there is a 90% chance that the true impact falls within the indicated confidence interval. The relative precision results indicated in the tables express the size of the confidence interval as a percentage of the point estimates.

Uncertainty analysis results for peak electric demand reduction impact estimates are summarized in Table 8-2. The results for the metered systems are much more precise than those for the unmetered sites. This result is expected because the measurement errors are modest. For large groups of systems the measurement errors tend to cancel each other out (i.e., the overestimates tend to cancel out the underestimates).

Table 8-2: MCS Study Peak Demand Impact Results - 90% Confidence

Level / Basis	ISO Peak Ratio (kW_P/kW Rebated)	90% Confidence Interval	Relative Precision
Level 1 PV	**0.45**	**0.43 to 0.47**	**±3.6%**
Metered	0.46	0.46 to 0.46	±0.1%
Estimated	0.44	0.41 to 0.47	±7.6%
Level 3/3N/3R	**0.64**	**0.60 to 0.68**	**±5.6%**
Metered	0.67	0.67 to 0.67	±0.1%
Estimated	0.61	0.54 to 0.68	±11.0%

[2] A 90% confidence level was selected because this criterion is frequently used for energy program impacts evaluation studies. The historical context behind this convention is summarized in the International Performance Measurement and Verification Protocol (1997 edition). The 90/10 convention may have been an extension of accuracy requirements specified earlier for utility load research studies.

Uncertainty analysis results for electric energy production impact estimates are summarized in Table 8-3. Again the uncertainty analysis indicates accuracy of at least 90/10 for program total energy impacts.

Table 8-3: MCS Study Annual Energy Impact Results - 90% Confidence

Level / Basis	Annual Capacity Factor	90% Confidence Interval	Precision
Level 1 PV	**0.157**	**0.153 to 0.161**	**±2.6%**
Metered	0.164	0.164 to 0.164	±0.1%
Estimated	0.154	0.147 to 0.160	±4.0%
Level 3/3N/3R	**0.42**	**0.39 to 0.46**	**±8.2%**
Metered	0.46	0.46 to 0.46	±0.1%
Estimated	0.40	0.35 to 0.45	±14.0%

Uncertainty analysis results for total program weighted average PUC218.5(b) efficiency of cogeneration systems are summarized in Table 8-4. The PUC218.5(b) efficiencies are calculated using electricity production, fuel use, and heat recovery data. For purposes of this summary table systems were considered metered if both electricity production and heat recovery were metered. In some cases the fuel use of these 'metered' systems was estimated.

Table 8-4: MCS Study PUC218.5(b) Impact Results - 90% Confidence

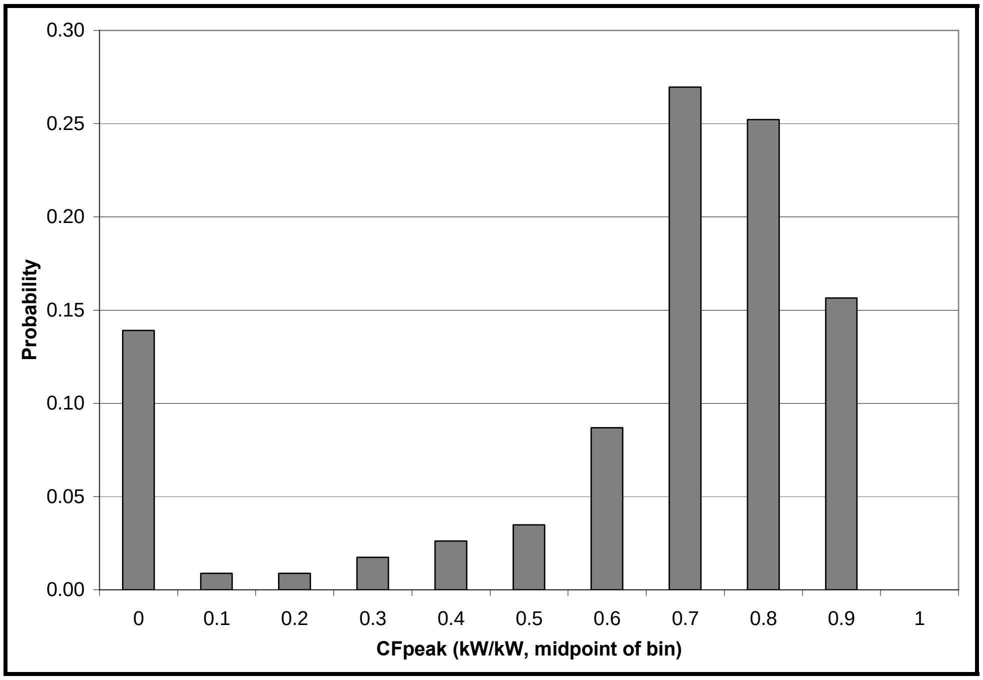
Level / Basis	218.5(b) Efficiency	90% Confidence Interval	Relative Precision
Level 3/3N	**40%**	**38% to 42%**	**4.4%**
Metered	40%	38% to 41%	3.4%
Estimated	40%	38% to 42%	5.3%

8.5 Discussion of Results

For cogeneration systems the electric energy impact estimates are more uncertain than the coincident peak demand impact estimates. This finding may be due to the fact that it is customary for most systems to operate during the middle of the day when peak demand impacts are realized. Conversely, some cogeneration systems operate only during the day, while others run continuously, even at night.

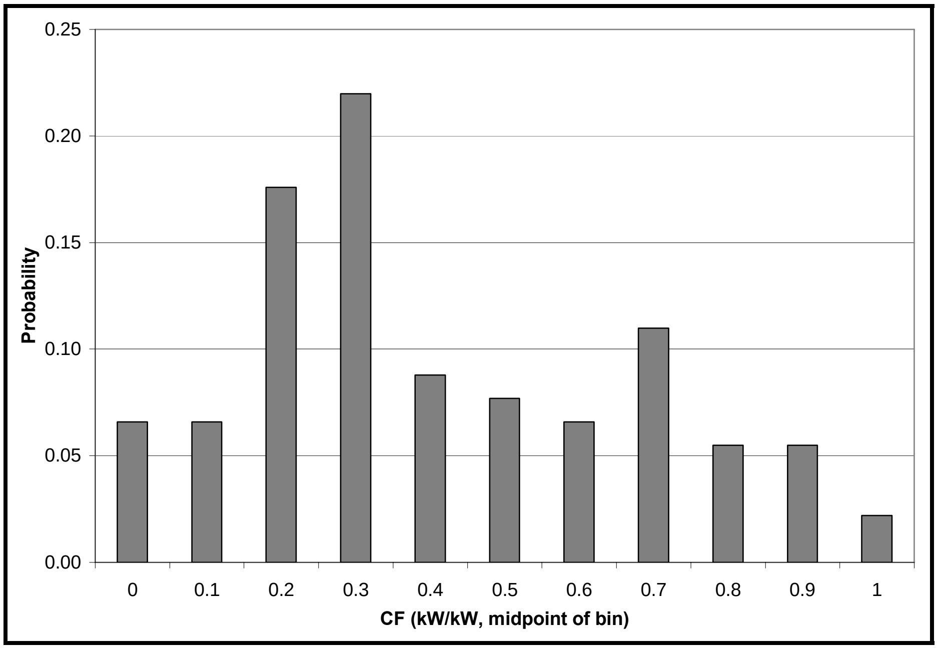
The performance distribution for cogeneration system coincident peak electric demand impacts is presented in Figure 8-4. This distribution indicates that during this single hour of the year some cogeneration systems were idle. Overall, approximately one in four systems was operating with a capacity factor between 0.65 and 0.75.

Figure 8-4: MCS Performance Distribution for Cogeneration System Coincident Peak Electric Demand Impacts



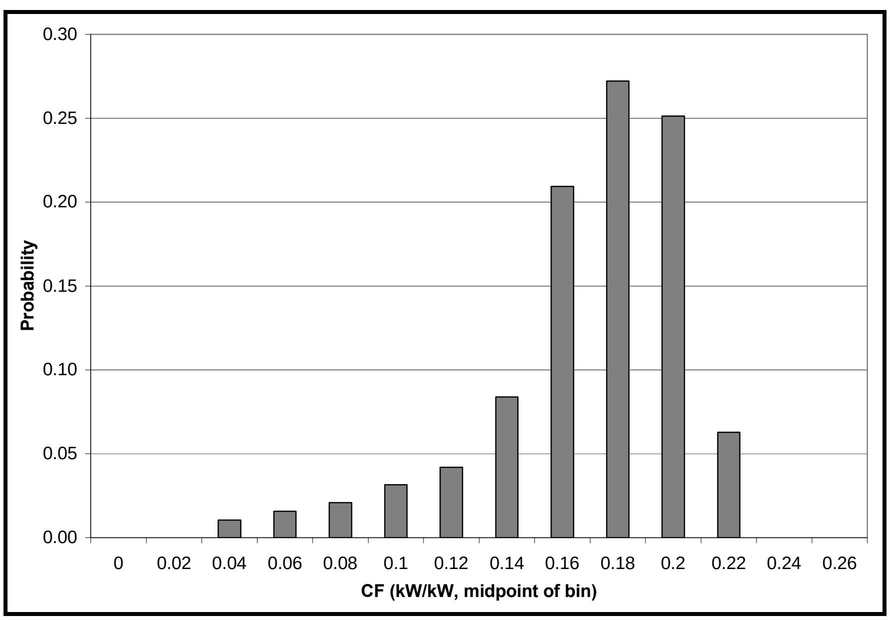
The performance distribution for cogeneration system annual electric energy impacts is presented in Figure 8-5. In this distribution an annual CF value equal to zero means that the system was idle for the entire year. Whereas 14 percent of unmetered systems were assumed idle during the coincident peak hour, only 7 percent were assumed to have been idle throughout the entire year.

Figure 8-5: MCS Performance Distribution for Cogeneration System Annual Electric Energy Impacts



The PV energy impact estimates are more accurate than the PV demand impact estimates. One of the factors contributing to this finding concerns the variability assumed for their respective performance factors. The performance distribution for PV system annual electric energy impacts is presented in Figure 8-6.

Figure 8-6: MCS Performance Distribution for PV System Annual Electric Energy Impacts



The distribution assumed for PV energy impact is much tighter than that assumed for PV demand impact. Over the course of entire years local factors that can affect performance for short periods of time tend to average out.

Metering rates also influence the relative uncertainty of electric impacts estimates reported for PV and cogeneration systems. However, during 2005 the electric metering rates for PV and cogeneration systems were similar and the difference in uncertainty levels is primarily due to the performance distribution variability issues discussed above.

Appendix A

Uncertainty Analysis for Impacts Estimates

Assumed performance distributions used in the Monte Carlo Simulation uncertainty analysis for unmetered systems are included under this cover along with summaries of performance observed for groups of metered projects.

A.1 Performance Distributions for Coincident Peak Demand Impacts

Figure A-1: PG&E PV Measured Coincident Peak Output (Coastal, Near Flat)

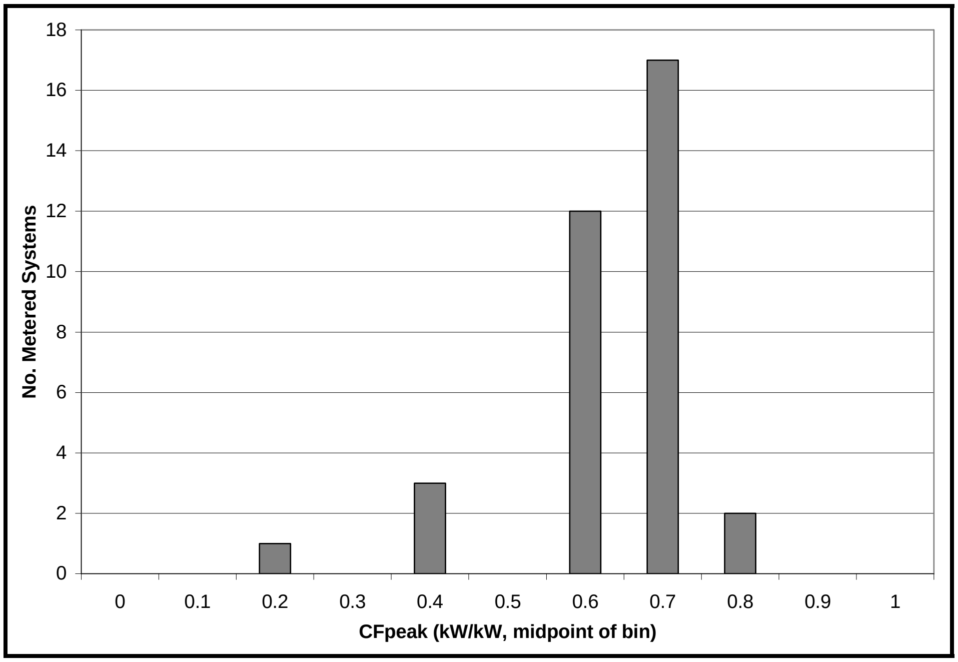


Figure A-2: MCS Distribution - PG&E PV Coincident Peak Output (Coastal, Near Flat)

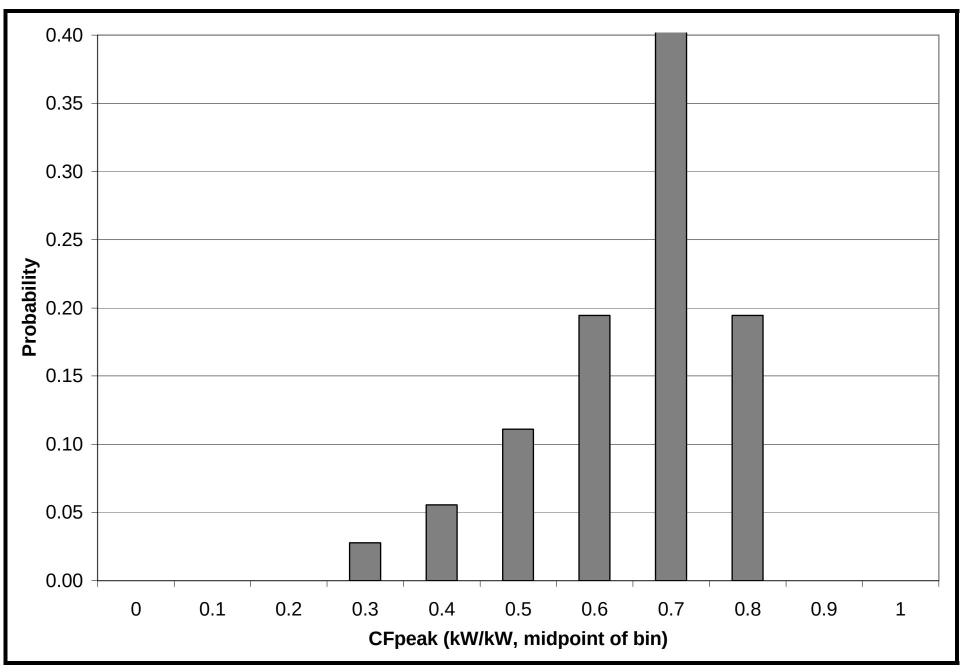


Figure A-3: PG&E PV Measured Coincident Peak Output (Coastal, Other)

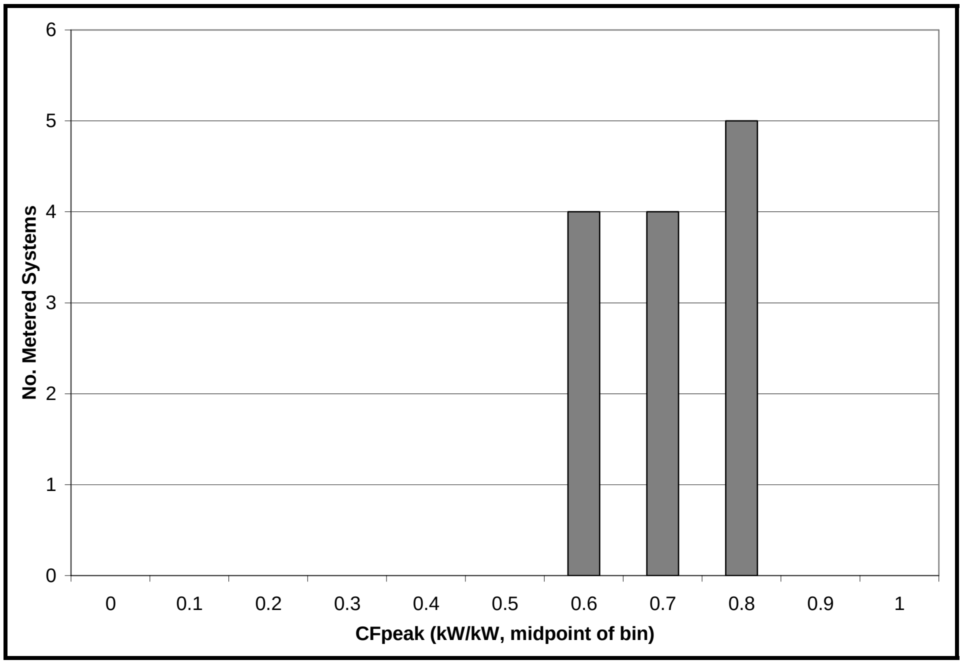


Figure A-4: MCS Distribution - PG&E PV Coincident Peak Output (Coastal, Other)

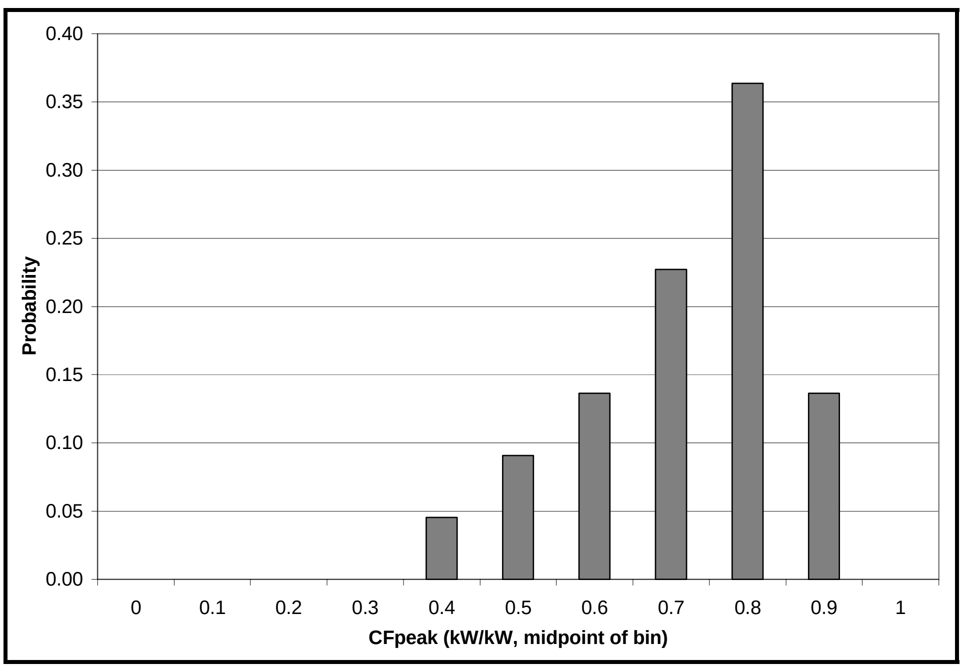


Figure A-5: PG&E PV Measured Coincident Peak Output (Inland, Near Flat)

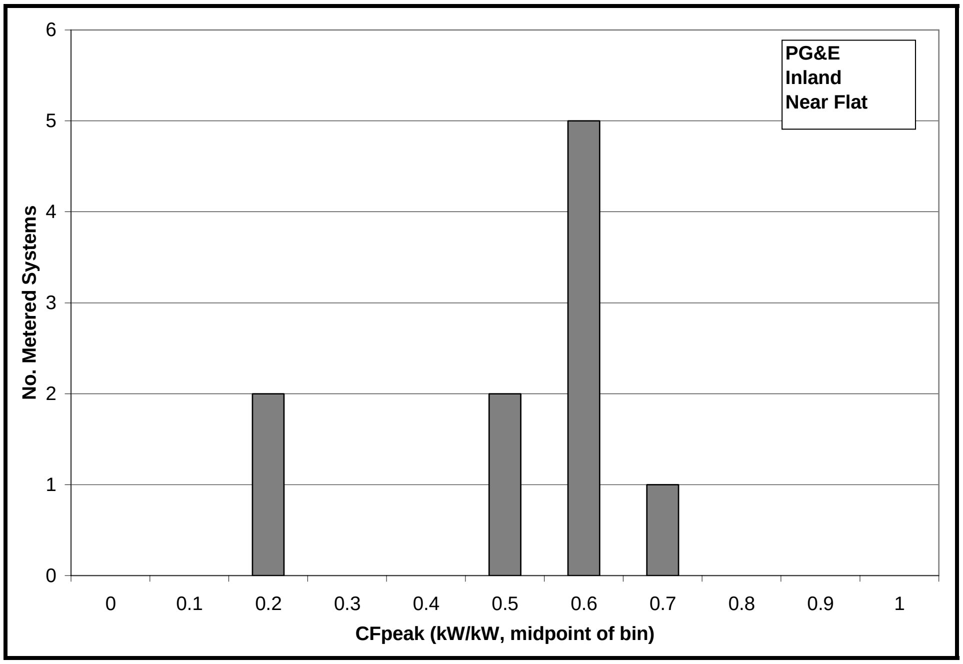


Figure A-6: MCS Distribution - PG&E PV Coincident Peak Output (Inland, Near Flat)

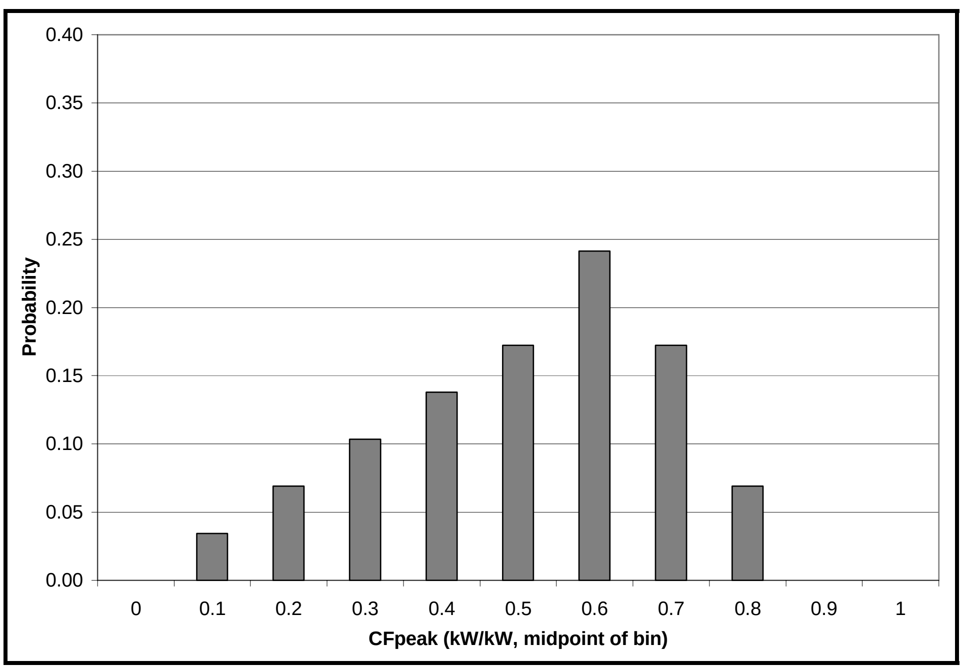


Figure A-7: PG&E PV Measured Coincident Peak Output (Inland, Other)

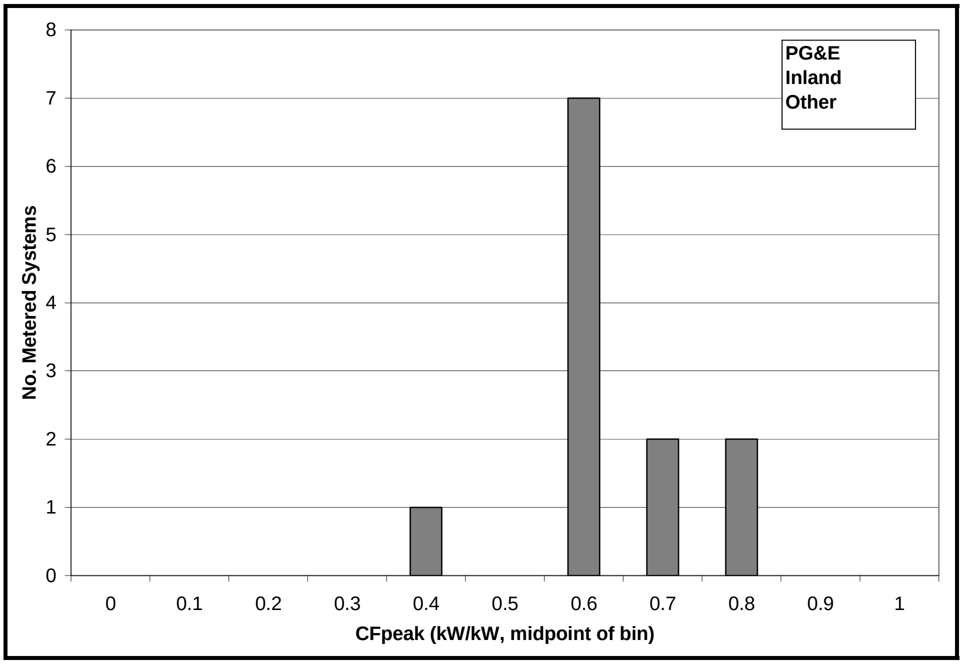


Figure A-8: MCS Distribution - PG&E PV Coincident Peak Output (Inland, Other)

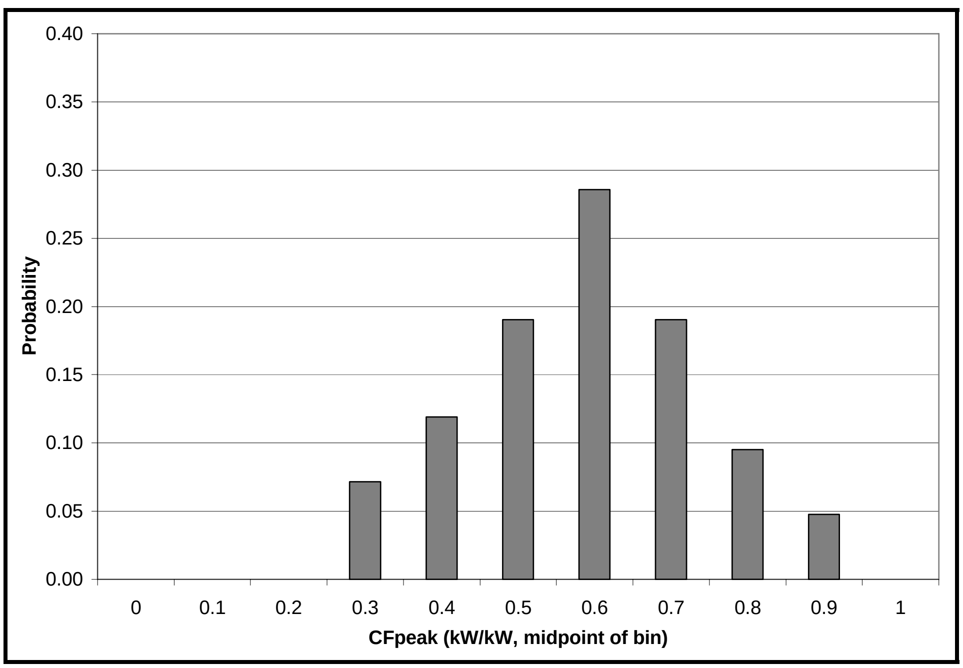


Figure A-9: LA PV Measured Coincident Peak Output

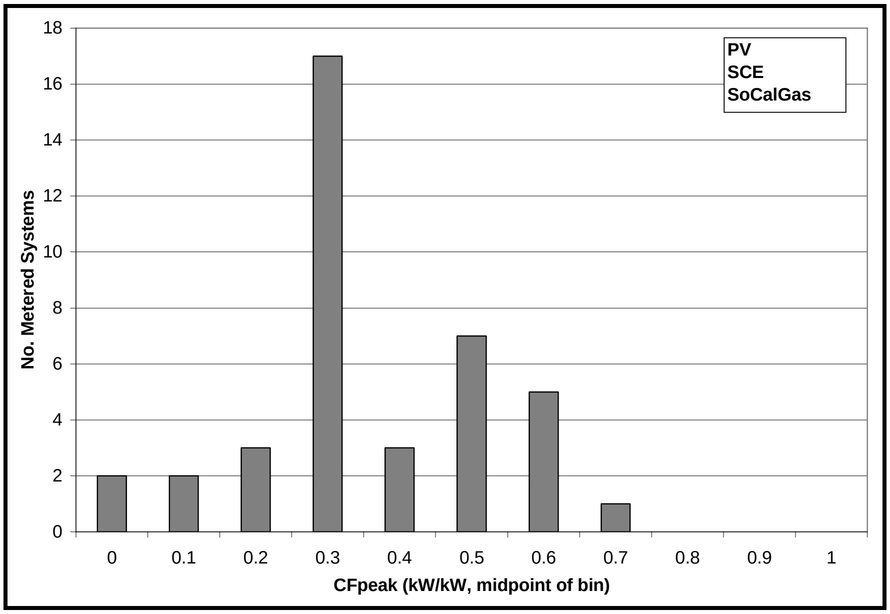


Figure A-10: MCS Distribution - LA PV Coincident Peak Output

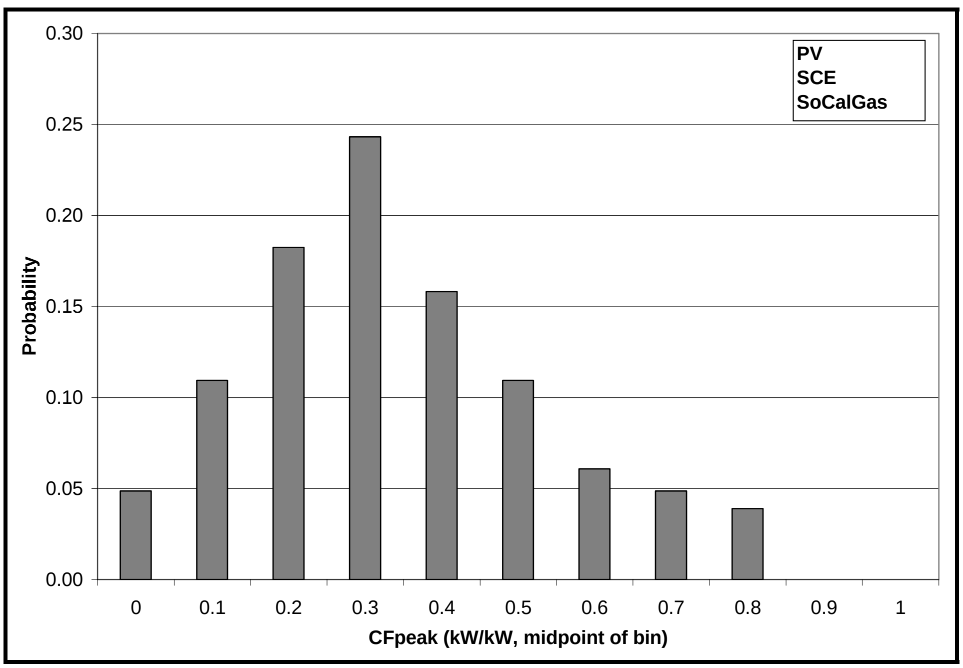


Figure A-11: SDREO PV Measured Coincident Peak Output (Coastal, Near Flat)

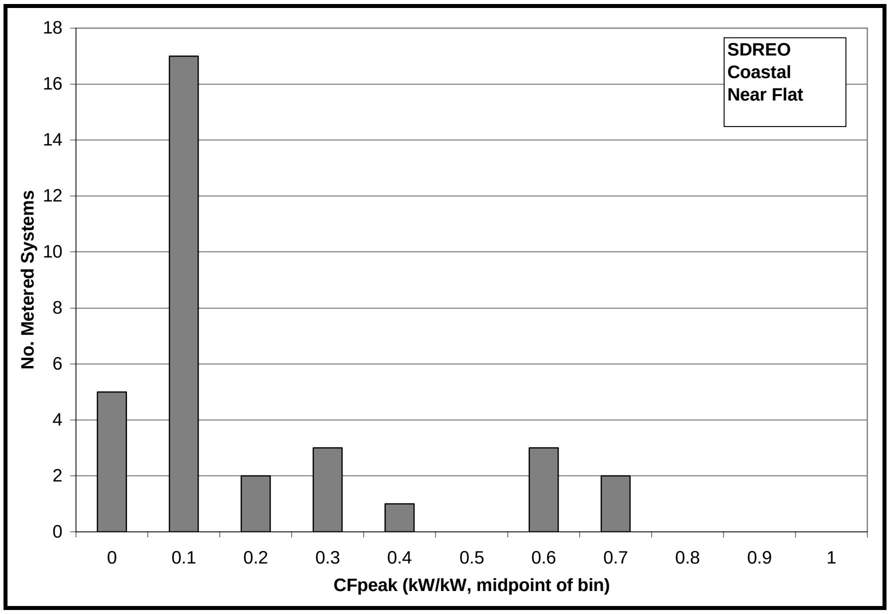


Figure A-12: MCS Distribution - SDREO PV Coincident Peak Output (Coastal, Near Flat)

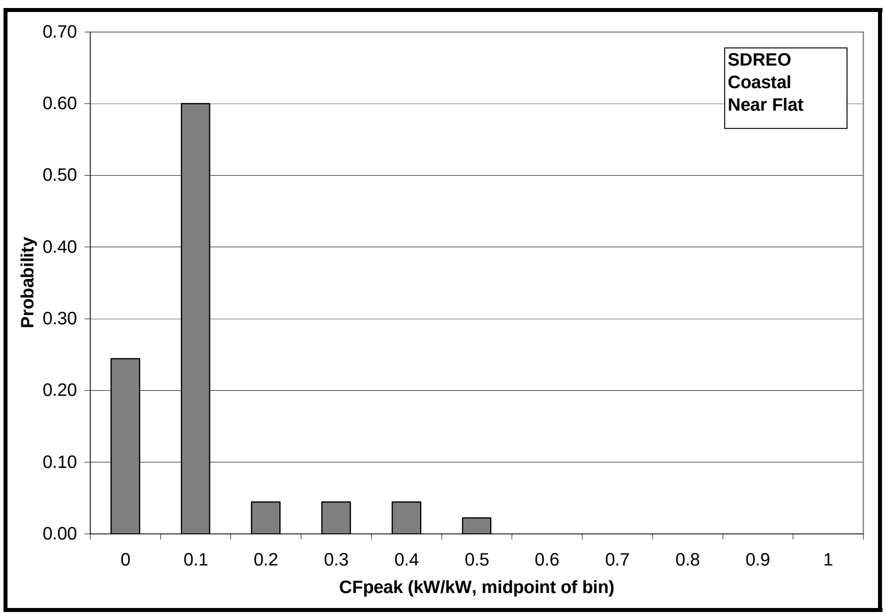


Figure A-13: CHP Measured Coincident Peak Output

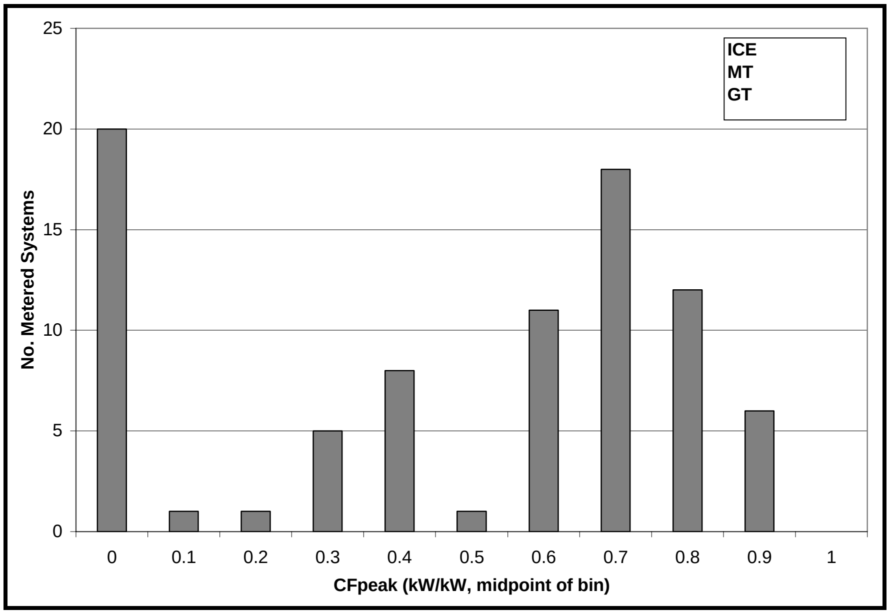
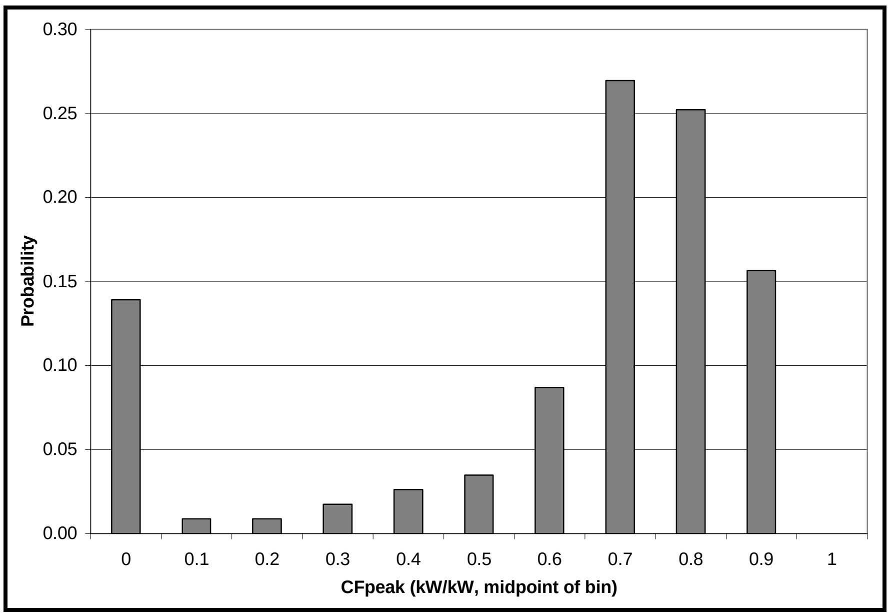


Figure A-14: MCS Distribution – CHP Coincident Peak Output



A.2 Performance Distributions for Energy Impacts

Figure A-15: PV Measured Energy Production (Capacity Factor)

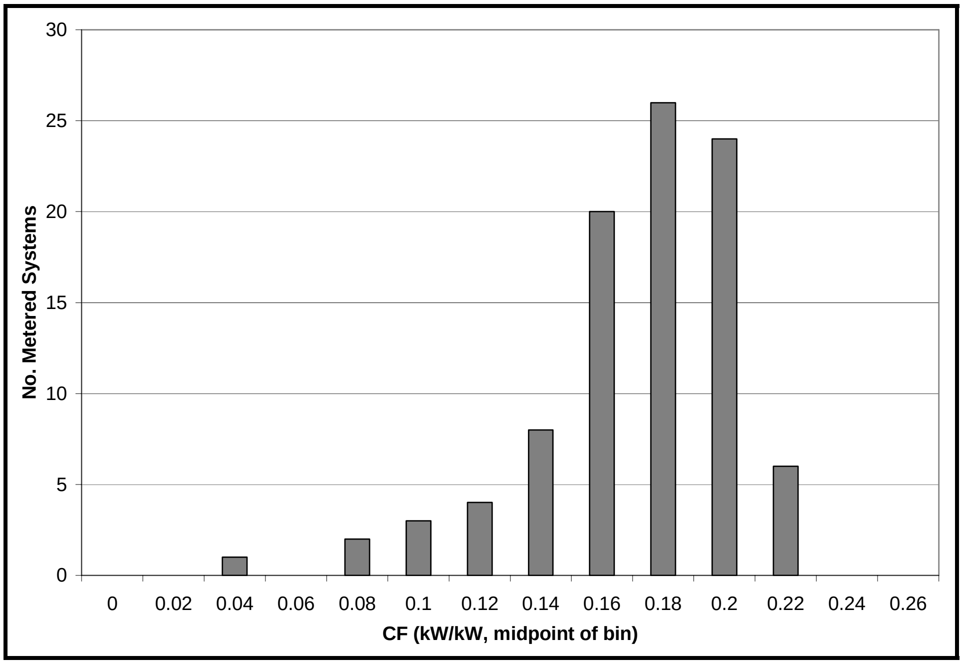


Figure A-16: MCS Distribution – PV Energy Production (Capacity Factor)

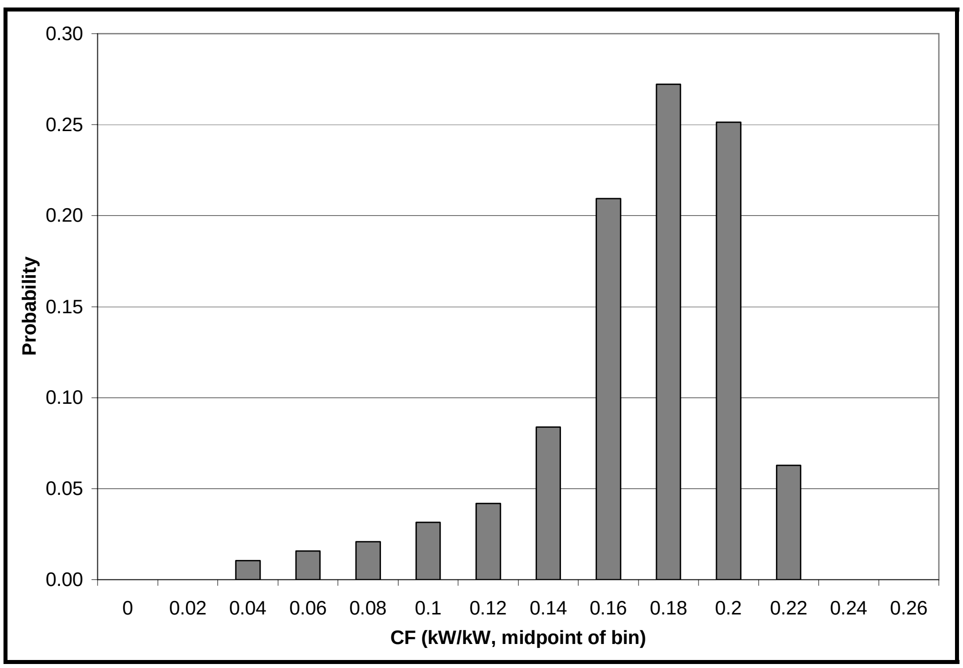


Figure A-17: CHP Measured Electricity Production (Capacity Factor)

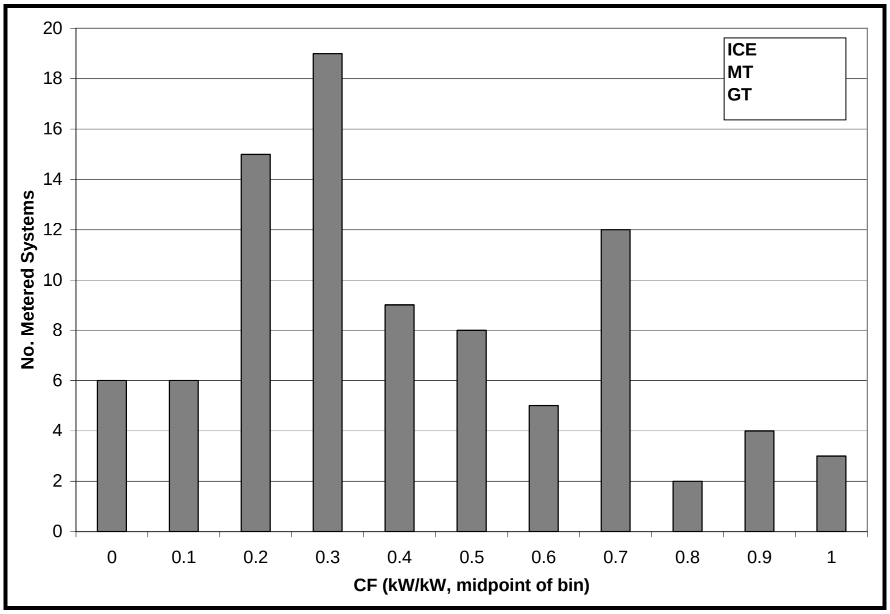


Figure A-18: MCS Distribution – CHP Electricity Production (Capacity Factor)

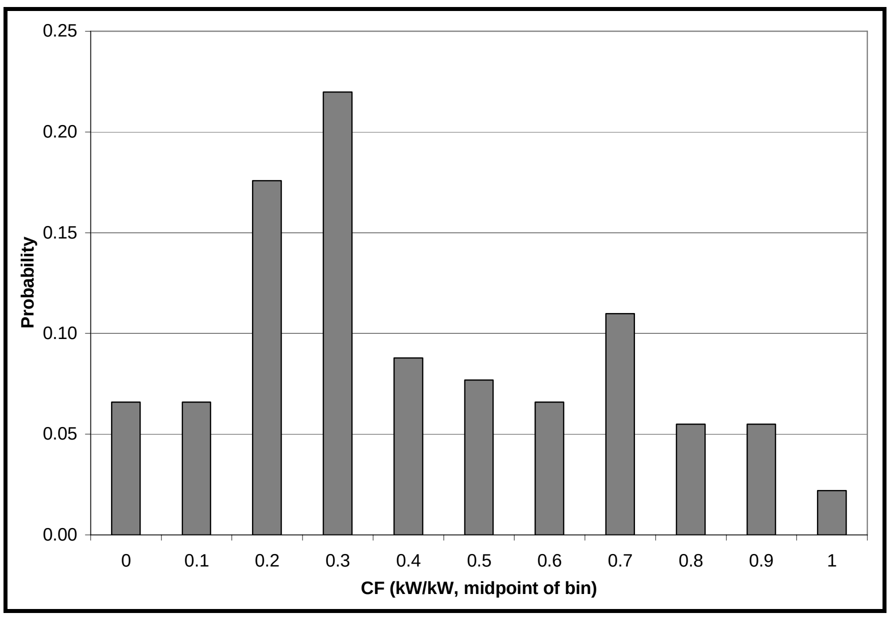


Figure A-19: CHP Measured Heat Recovery Rate

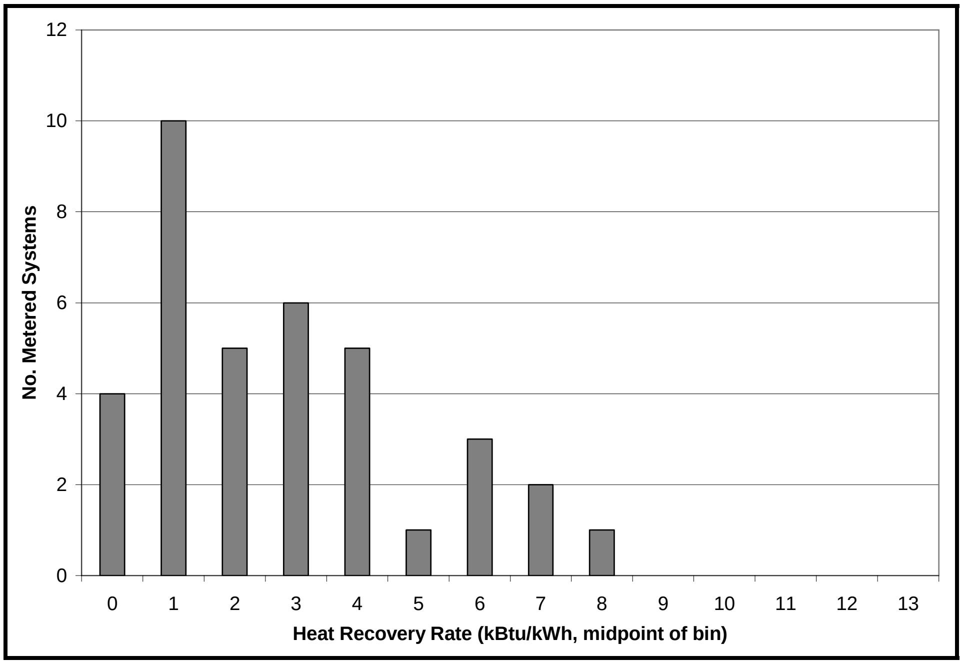
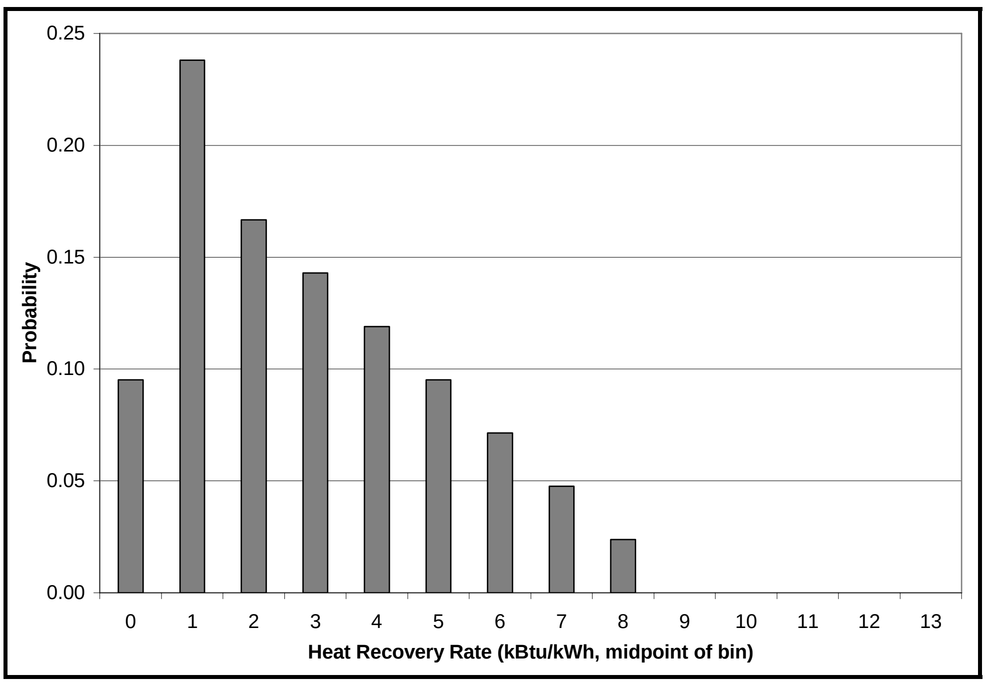


Figure A-20: MCS Distribution – CHP Heat Recovery Rate



Appendix B

Greenhouse Gas Emissions Reduction Methodology

This appendix provides details regarding the methodology used to estimate the net reduction in greenhouse gas (GHG) emissions from the operation of SGIP systems on-line during PY05. The GHG emissions considered in this analysis are carbon dioxide (CO_2) and methane (CH_4), as these are the two primary pollutants whose emissions are potentially affected by the operation of SGIP systems.

B.1 Net GHG Emission Reductions

Net emission reductions of methane and carbon dioxide are quantified in this analysis by examining the emissions that occur during the following processes:

- When in operation, power generated by SGIP systems directly displaces grid electricity that would have been generated from central station power plants.[1] As a result, SGIP projects displace the accompanying CO_2 emissions that these central station power plants would have released to the atmosphere. CO_2 emissions from these central station power plants are estimated on an hour by hour basis over all 8760 hours of the 2005 year[2]. The CO_2 estimates are based on a methodology developed by Energy and Environmental Economics, Inc. (E^3).[3]
- The operation of specific cogeneration systems such as microturbines (MT), fuel cells (FC), gas turbines (GT), and reciprocating internal combustion engines (ICE) emits CO_2. While CO_2 emissions from central power plants are

[1] In this analysis, we compare GHG emissions from SGIP facilities only to GHG emissions from utility power generation that could be subject to economic dispatch (i.e., central station natural gas-fired combined cycle facilities and simple cycle gas turbine peaking plants). We assume that operation of SGIP facilities have no impact on electricity generated from utility facilities not subject to economic dispatch. Consequently, comparison of SGIP facilities to nuclear or hydroelectric facilities is not made as neither of these facilities are subject to dispatch.

[2] Consequently, during those hours when a SGIP facility is not in operation, displacement of CO_2 emissions from central station power plants is equal to zero.

[3] Energy and Environmental Economics for the California Public Utilities Commission, "Methodology and Forecast of Long Term Avoided Costs for the Evaluation of California Energy Efficiency Programs," October 25, 2004.

avoided due to SGIP systems, the SGIP cogeneration plants are responsible for the generation of CO_2 emissions as well. Emissions of CO_2 from SGIP facilities are estimated based on hour by hour electricity generated from SGIP facilities over all 8760 hours of the 2005 year.

- Waste heat recovered from the operation of cogeneration systems displaces natural gas that would have been used to fuel boilers responsible for producing process heating at the customer host site. This displaces accompanying CO_2 emissions from the boilers, which are taken into account by calculating the CO_2 emissions avoided from using natural gas to fuel boilers. Since virtually all fuel carbon in natural gas is converted to CO_2 during combustion, the amount of CH_4 released from incomplete combustion is considered insignificant and is not included in the estimated reduction in GHG from SGIP systems.
- Recovery of waste heat also displaces electricity (and the accompanying CO_2) emissions that would have been used to operate electric chillers. Estimates of CO_2 emissions are based on the hour by hour electricity savings from central station facilities; and
- Renewable fuel use facilities with a capacity less than 400 kW, such as dairies, small landfill sites, and wastewater treatment plants, are assumed to capture CH_4 that typically would have been vented and instead, use it for energy purposes. The avoided CH_4 emissions represent a direct reduction of greenhouse gases. For biogas generated from wastewater treatment facilities and landfill gas recovery operations that are used in SGIP facilities equal to or greater than 400 kW in rebated capacity, it was assumed this biogas would have been flared if not used at a SGIP renewable fuel use facility. Flaring was assumed to have essentially the same degree of combustion completion as SGIP renewable fuel use facilities. Consequently, for renewable fuel use facilities equal to or larger than 400 kW, there is no net CH_4 benefit.

Section B.2 presents an overview of the estimation technique used to calculate reductions in CH_4 emissions from renewable fuel use facilities and therefore focuses on quantifying the avoided CH_4 emissions from renewable fuel use facilities with a capacity less than 400 kW. Section B.3 presents the methodology for the estimation of net reductions in CO_2 emissions. Since SGIP systems emit CO_2 while generating electricity, the release of these emissions must be accounted for in addition to the reduction in CO_2 resulting from the reliance on recovered waste heat and reduced use of electricity generated by conventional power plants.

B.2 Methodology for the Calculation of Methane Emission Reductions

Calculation of CH_4 emission reductions from cogeneration facilities was carried out for the subset of 16 renewable fuel use facilities in the SGIP system. These facilities used exclusively or predominately biogas as the generation fuel source. These included the following facility types:

- Renewable-Powered Fuel Cells;
- Renewable-Fueled Microturbines;
- Renewable-Fueled Internal Combustion Engines; and
- Renewable-Fueled Small Gas Turbines.

The baseline treatment of biogas is important in assessing the methane emission impacts of renewable fuel facilities. Baseline treatment refers to the typical fate of the biogas in lieu of being used for energy purposes (e.g., the biogas could be vented directly to the atmosphere or flared). There are three common sources of biogas: landfills, wastewater treatment facilities, and dairies. For dairy digesters, the baseline is usually to vent any generated biogas to the atmosphere. Of the approximately 2000+ dairies in California, conventional manure management practice for flush dairies[4] has been to pump the mixture of manure and water to an uncovered lagoon. Naturally occurring anaerobic digestion processes convert carbon present in the waste into carbon dioxide and water. Because these lagoons are typically uncovered, all of the methane generated in the lagoon escapes into the atmosphere. Currently, there are no requirements that dairies capture and flare the biogas, although some air pollution control districts are considering anaerobic digesters as a possible Best Available Control Technology (BACT) for control of volatile organic compounds. Consequently, the baseline used in this report for dairy digesters is venting of the methane to the atmosphere.

For wastewater treatment facilities, the baseline is not as straightforward. There are approximately 250 wastewater treatment plants (WWTP) in California. Fewer than 30 of the WWTP conduct energy recovery. The larger facilities (i.e., those that could generate 1 MW or more of electricity) tend to install energy recovery systems. However, the vast majority of the remaining WWTP do not recover energy, and most flare the gas on an infrequent basis. Consequently, for smaller facilities (i.e., those < 400 kW in capacity), venting of the biogas (i.e., venting of the methane) is used as the baseline.

Landfill gas recovery operations present the biggest challenge in defining the methane treatment baseline. A study conducted by the California Energy Commission in 2001[5] showed that landfills with biogas capacities less than 500 kW, would tend to vent rather than flare the generated landfill gas by a margin of over three to one. Consequently, for

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[4] Most dairies manage their wastes via flush, scrape or some mixture of the two processes. While manure management practices for any of these processes will result in methane being vented to the atmosphere, flush dairies are the most likely candidates for installing anaerobic digesters (i.e., dairy biogas systems).

[5] California Energy Commission, "Landfill Gas to Energy Potential in California," 500-02-041V1, September 2002

this impacts evaluation, the baseline for landfill gas facilities less than 400 kW is to vent the methane to the atmosphere. For landfill gas facilities equal to or greater than 400 kW, the baseline is considered flaring of the biogas. In situations where flaring occurs, the net methane impact is zero. In essence, combustion of methane in a flare or in a SGIP facility results in zero emissions of methane to the atmosphere.

Methane captured and used at renewable fuel use facilities where the baseline is venting represents CH_4 emissions that are no longer emitted to the atmosphere. Biogas consumption is not metered at SGIP facilities. However, electricity generated from SGIP facilities is metered on an hour by hour basis and can be used in conjunction with the electrical efficiency of the SGIP facility to estimate methane emissions. Nearly all SGIP renewable use facilities in 2005 used IC engines or microturbines as the prime mover. An electrical efficiency of 29 percent is considered representative of these facilities. Consequently, a methane emissions factor was calculated as follows:

$$CH_4 \cong \left(\frac{3412\ Btu}{kWhr}\right)\left(\frac{1}{.29}\right)\left(\frac{ft^3 of\ CH_4}{1000\ Btu}\right)\left(\frac{lbmole\ of\ CH_4}{360\ ft^3}\right)\left(\frac{16\ lb_m\ of\ CH_4}{lbmole\ of\ CH_4}\right)\left(\frac{454\ grams}{lb_m}\right)$$

$$\cong 246\ \frac{grams}{kWhr}$$

The derived emission factor of 246 grams of CH_4 per kWh of generated electricity is multiplied by the total electricity generated from the SGIP renewable fuel use sites to estimate the annual avoided CH_4 emissions. Since GHG emissions are often reported in terms of tons of CO_2 equivalent[6], each facility's avoided CH_4 emissions were converted first from grams to pounds and then pounds to metric tons. The equation used to calculate the reduction in CH_4 emissions for site j, is equal to:

Avoided CH_4 emissions in 2005 by site j (in tons of CH_4 reduced)	=	*246 grams/kWh * electricity generated in 2005 by site j * 0.002204 lbs/grams ÷ 2,205 lbs/metric ton*

The avoided tons of CH_4 emissions were then converted to tons of CO_2 equivalent by multiplying the avoided methane emissions by 21 CO_2 equivalent, which represents the Global Warming Potential (GWP) of methane (relative to carbon dioxide) over a 100

[6] Carbon dioxide equivalent is a metric measure used to compare the emissions of various greenhouse gases based upon their global warming potential (GWP). The carbon dioxide equivalent for a gas is derived by multiplying the tons of the gas by the associated GWP. OECD Glossary of Statistical Terms, http://stats.oecd.org/glossary/detail.asp?ID=285

year time horizon. Based on the methodology described above, the methane reduction from SGIP systems in PY05 equal to 49,122 in CO_2 equivalent, as shown in Table 5-14 in Section 5 of this report.

B.3 Methodology for the Calculation of Carbon Dioxide Emission Reductions

This section describes the methodology used to calculate the net reduction of carbon dioxide emissions from SGIP facilities during PY05. The methodological approach used for this analysis relies upon the multiplication of emission factors (in pounds of CO_2 per kWh of electricity generated) that are technology, location, and hour-specific by the total kWh generated by SGIP cogeneration sites during 2005. The different technologies that are accounted for include fuel cells, internal combustion engines, microturbines, and gas turbines. The location or service territory of a cogeneration site is also considered in the development of emission factors by accounting for whether the facility is located in PG&E's territory (northern California) or in SCE/SDG&E's territory (southern California). The geographic location naturally has an effect on the demand and use of electricity due to differences in climate and electricity market conditions. This in turn affects the emission factors used to estimate the avoided CO_2 released by conventional power plants. Lastly, the date and time that electricity is generated affects the emission factors because the mix of high and low efficiency plants used differ throughout the day. The larger the proportion of low efficiency plants that would have been used to generate electricity, the greater are the avoided CO_2 emissions.

Underlying Assumption of CO_2 Emissions Factors

As described above, there are a number of elements that can affect the emission factors used to calculate the overall net emission reductions of CO_2 for SGIP facilities. The basic methodology used to formulate emission factors for this analysis relies upon certain assumptions made by Energy and Environmental Economics, Inc. (E^3) in their emission factor development and these are as follows:

- The emissions of CO_2 released from a conventional power plant depends upon its heat rate, which in turn is dictated by the power plant's efficiency, and
- The mix of high and low efficiency plants in operation is determined by the price and demand for electricity at that time.

Hourly carbon dioxide emission factors used in this study were based upon a methodology initially developed by Energy and Environmental Economics, Inc. (E^3). E^3 provided CO_2 emission factors and the basis for those factors in a workbook available for download on their website.[7] The premise for hourly CO_2 emission factors calculated in E^3's workbook is that the marginal power plant relies on natural gas to generate electricity. Variations in the price of natural gas reflect the market demand conditions for electricity; as demand for electricity increases, all else equal, the price of natural gas will rise. To meet the higher demand for natural gas, utilities will have to rely more heavily on less efficient power plants once production capacity is reached at their relatively efficient plants. This means that during periods of higher electricity demand, there is increased reliance on lower efficiency plants, which in turn leads to a higher emission factor for CO_2. In other words, one can expect an emission factor representing the release of CO_2 from the central grid to be higher during peak hours than during off-peak hours.

The E^3 workbook mentioned above includes the price of natural gas for each hour over the year 1999 presented as the percentage of the annual average price of natural gas for 1999. Two streams of hourly natural gas prices exist: one for northern California and another for southern California. These "price shape" data streams dictate the mix of high and low efficiency power plants used by the conventional power grid to meet demand. During the hours where the price of natural gas is high (e.g., weekday, on-peak versus weekend or holiday, off-peak), the demand for electricity is met using high-efficiency as well as low efficiency peaking power plants ("peakers"). The price of natural gas is used to calculate an implied heat rate, which is dependent on the mix of low and high efficiency power plants. This implied heat rate is used to calculate the tons of CO_2 per kWh emission factors for each hour of the year. The greater the demand during these times (as indicated by a higher hourly price for natural gas), the higher the percentage of electricity generated by peakers and the greater the benefit of relying upon SGIP systems.

Base CO_2 Emission Factors

Two streams of 8760 hourly emission factors for 1999 are included in the E^3 workbook; one is for Pacific Gas and Electric Company (hereafter these factors will be referred to as the northern California CO_2 emission factors) and the other is for Southern California Edison and San Diego Gas and Electric Company (hereafter referred to as the southern California CO_2 emission factors). Inputs to develop the hourly emission factors are geographically dependent due to different weather conditions, different central station plant heat rates, and different natural gas market conditions.

The basic hourly CO_2 emission factor (EF) equation (represented in tons per MWh) is described below:

[7] The filename of the workbook that contains the data used to generate hour-specific emission factors for CO_2 is called cpucAvoided26.xls and can be downloaded from www.ethree.com/CPUC.

$BaseCO_2\ EF_{it}$ = high efficiency plant CO_2 EF + (implied heat rate$_{it}$ – high efficiency Plant heat rate)[(low efficiency plant CO_2 EF - high efficiency plant CO_2 EF)/(low efficiency plant heat rate – high efficiency plant heat rate)]*

where i =NC for northern California and SC for southern California
t = hour, 1 to 8760 in year 1999

This equation shows that for a given time *t*, the emission factor is dependent upon how the implied heat rate of the average power plant differs from the average heat rate of a high efficiency power plant. The higher the heat rate (which indicates a heavier reliance on lower efficiency plants, such as during times of high electricity demand), the greater is the emission factor. To calculate the base hourly emission factor values, we rely upon the parameters and "price shape" data or percentage mix representing low and high efficiency plants in operation that E^3 presents in its workbook. These are as follows:

high efficiency plant CO_2 EF (tons per MWh) = 0.3650

low efficiency plant CO_2 EF (tons per MWh) = 0.8190

high efficiency plant heat rate = 6,240

low efficiency plant heat rate = 14,000

*implied heat rate$_{it}$ = current price of natural gas$_{it}$/annual average price of natural gas$_{it}$ * avg heat rate$_i$*

where i= NC, SC
t = hours 1 to 8760 in year 1999

avg heat rate$_{NC}$ =9,160 for NC
avg heat rate$_{SC}$ = 9,590 for SC

If implied heat rate$_t$ < 6,240, then implied heat rate$_t$ = 6,240
If implied heat rate$_t$ > 14,000 then implied heat rate$_t$ = 14,000
(implied heat rate is bounded by low and high efficiency plant heat rates)

The base hourly emission factor values, as calculated here, are presented in tons per MWh. We converted these factors into lbs. per kWh by multiplying the factors by the conversion rate of 2,205 lbs. /metric ton and then dividing by 1,000 kWh for ease of application and consistency across the emission factors calculated for CH_4.

Since we required CO_2 emissions avoided for every hour of the year 2005 to be able to calculate the net emission reductions of this primary component of greenhouse gases, simply lining up the hourly emission factors from 1999 to the hourly totals of electricity generated from power plants in 2005 would not work due to the possible differences in days of the week. Upon examination of these two years, we determined that January 1, 1999 fell on a Friday while January 1, 2005 fell on a Saturday. To properly align the emission factors for the correct day type, the emission factor value for 1/1/1999 was removed from both the northern and southern California price streams and moved up. This adjustment was made so that the emission factor value calculated for Saturday, January 2, 1999 could be multiplied by the electricity supplied by the conventional grid on Saturday, January 1, 2005. This realignment allowed for us to maintain the proper days of the week over the year for the emissions factor values. However, this adjustment left a missing day at the end of the year. To correct for this, the emission factor value for the last Saturday of the month of December, 12/25/1999, was used for the last day of 2005, which also fell on a Saturday.

Technology-Specific Adjustments to CO_2 Emission Factors

The above location- and hour-specific emission factors, when multiplied by the quantity of electricity generated each hour estimate the *hourly emissions avoided when electricity from SGIP sites is used in lieu of electricity from the grid*. Earlier in this appendix, it was noted that SGIP sites are also responsible for emitting CO_2; this must also be taken into account when calculating the net emission reductions of CO_2 for SGIP facilities. The following assumptions were made regarding the emissions generated per kWh of electricity generated for the various cogeneration technologies:

$$
\begin{aligned}
SGIPCO_2\ EF_a \text{ (in lbs. per kWh)} &= 1.99 \text{ when } a = \text{Gas Turbine} \\
&= 1.99 \text{ when } a = \text{Microturbine} \\
&= 1.44 \text{ when } a = \text{IC Engine} \\
&= 0.99 \text{ when } a = \text{Fuel Cell}
\end{aligned}
$$

The equations used to derive the technology-specific component of the emission factors are as follows:

Microturbine and Gas Turbine equation: uses electrical efficiency of 21%

$$
(CO_2)_{MT} \cong \left(\frac{3412\ Btu}{kWhr}\right)\left(\frac{1}{.21}\right)\left(\frac{ft^3 of\ CH_4}{1000\ Btu}\right)\left(\frac{lbmole\ of\ CH_4}{360\ ft^3}\right)\left(\frac{lbmole\ of\ CO_2}{lbmole\ of\ CH_4}\right)\left(\frac{44\ lbs\ of\ CO_2}{lbmole\ of\ CO2}\right)
$$

$$
\cong \frac{1.99\ lbs\ of\ CO2}{kWhr}
$$

IC Engine equation: uses electrical efficiency of 29%

$$(CO_2)_{ICE} \cong \left(\frac{3412\ Btu}{kWhr}\right)\left(\frac{1}{.29}\right)\left(\frac{ft^3 of\ CH_4}{1000\ Btu}\right)\left(\frac{lbmole\ of\ CH_4}{360\ ft^3}\right)\left(\frac{lbmole\ of\ CO_2}{lbmole\ of\ CH_4}\right)\left(\frac{44\ lbs\ of\ CO_2}{lbmole\ of\ CO2}\right)$$

$$\cong \frac{1.44\ lbs\ of\ CO2}{kWhr}$$

Fuel Cell equation: uses electrical efficiency of 42%

$$(CO_2)_{FC} \cong \left(\frac{3412\ Btu}{kWhr}\right)\left(\frac{1}{.42}\right)\left(\frac{ft^3 of\ CH_4}{1000\ Btu}\right)\left(\frac{lbmole\ of\ CH_4}{360\ ft^3}\right)\left(\frac{lbmole\ of\ CO_2}{lbmole\ of\ CH_4}\right)\left(\frac{44\ lbs\ of\ CO_2}{lbmole\ of\ CO2}\right)$$

$$\cong \frac{0.99\ lbs\ of\ CO2}{kWhr}$$

The technology-specific emission factors were calculated to account for CO_2 emissions released from SGIP sites and therefore, when multiplied by the electricity generated from cogeneration sites, represents an increase in CO_2 emissions.

Waste Heat Recovery Adjustment to CO_2 Emission Factors

The fourth bullet presented in Section B.1 of this appendix described additional GHG reduction benefits derived from cogeneration. These benefits come in the form of waste heat recovered from SGIP facilities that is then used for energy purposes, and hence avoids additional reliance on electricity from conventional power plants. The application of these emission factors was dependent upon the presence of a natural gas boiler and whether or not recovered waste heat is used to fuel the boiler (this was indicated through a *boilerflag* dummy variable).

The emission factor adjustment made to account for the recovery of waste heat is technology dependent, just as the CO_2 emissions released from cogeneration facilities was technology dependent as well. The following heat recovery factors (HRFs) were applied for those facilities that are able to recover waste heat for use in boilers:

$$\begin{aligned} HRF_a \text{ (in lbs. per kWh)} &= 0.97 \text{ when } a = \text{Gas Turbine} \\ &= 0.49 \text{ when } a = \text{Microturbine} \\ &= 0.34 \text{ when } a = \text{IC Engine} \\ &= 0.21 \text{ when } a = \text{Fuel Cell} \end{aligned}$$

The equations used to derive these components of the emission factors are as follows:

Gas Turbine equation: uses heat recovery factor of 7.9 kBtu/kWhr

$$(CO_2)_{GTWH} \cong \left(\frac{7.9\ kBtu}{kWhr}\right)\left(\frac{ft^3 of\ CH_4}{1000\ Btu}\right)\left(\frac{lbmole\ of\ CO_2}{360\ ft^3}\right)\left(\frac{44\ lbs\ of\ CO_2}{lbmole\ of\ CO2}\right)$$

$$\cong \frac{0.97\ lbs\ of\ CO2}{kWhr}$$

Microturbine equation: uses heat recovery factor of 4.0 kBtu/kWhr

$$(CO_2)_{MTWH} \cong \left(\frac{4.0\ kBtu}{kWhr}\right)\left(\frac{ft^3 of\ CH_4}{1000\ Btu}\right)\left(\frac{lbmole\ of\ CO_2}{360\ ft^3}\right)\left(\frac{44\ lbs\ of\ CO_2}{lbmole\ of\ CO2}\right)$$

$$\cong \frac{0.49\ lbs\ of\ CO2}{kWhr}$$

IC Engine equation: uses heat recovery factor of 2.8 kBtu/kWhr

$$(CO_2)_{ICEWHE} \cong \left(\frac{2.8\ kBtu}{kWhr}\right)\left(\frac{ft^3 of\ CH_4}{1000\ Btu}\right)\left(\frac{lbmole\ of\ CO_2}{360\ ft^3}\right)\left(\frac{44\ lbs\ of\ CO_2}{lbmole\ of\ CO2}\right)$$

$$\cong \frac{0.34\ lbs\ of\ CO2}{kWhr}$$

Fuel Cell equation: uses heat recovery factor of 1.7 kBtu/kWhr

$$(CO_2)_{FCWH} \cong \left(\frac{1.7\ kBtu}{kWhr}\right)\left(\frac{ft^3 of\ CH_4}{1000\ Btu}\right)\left(\frac{lbmole\ of\ CO_2}{360\ ft^3}\right)\left(\frac{44\ lbs\ of\ CO_2}{lbmole\ of\ CO2}\right)$$

$$\cong \frac{0.21\ lbs\ of\ CO2}{kWhr}$$

These emission factors are based on the ability of waste heat to be recovered and used in lieu of energy from the conventional power grid and are therefore calculated as a reduction in CO_2 emissions (an environmental benefit).

Absorption Chiller Adjustment to CO_2 Emission Factors

The fifth bullet presented in Section B.1 of this appendix described one last additional GHG reduction benefit derived from the presence of absorption chillers present in cogeneration facilities. Since absorption chillers can replace the use of standard efficiency centrifugal chillers that operate using electricity from the central power plant, there are avoided CO_2 emissions that translate to a reduction in GHG emissions.

Actual heat recovery rates and typical absorption and centrifugal chiller efficiencies were incorporated into an algorithm to estimate the avoided electricity that would have been serving the centrifugal chiller in the absence of the cogeneration system. This component of the emission factors are also technology specific:

$$\begin{aligned} CHF_a \text{ (in lbs. per kWh)} \quad &= 0.29 \text{ when } a = \text{Gas Turbine} \\ &= 0.15 \text{ when } a = \text{Microturbine} \\ &= 0.10 \text{ when } a = \text{IC Engine} \\ &= 0.06 \text{ when } a = \text{Fuel Cell} \end{aligned}$$

The equations used to derive this component of the emission factors are as follows:

Gas Turbine equation: uses heat recovery factor of 7.9 kBtu/kWhr

$$(CO_2)_{GTC} \cong \left(\frac{7.9\ kBtu}{kWhr_{ENGO}}\right)\left(\frac{0.7\,Btu_{in}}{Btu_{out}}\right)\left(\frac{0.634\ kWhr_{ENGO}}{ton\ of\ cooling}\right)\left(\frac{ton\ of\ cooling}{12\ kBtu}\right)\left(\frac{lb\ of\ CO_2}{kWhr_{elecin}}\right)$$

$$\cong \frac{0.29\ lbs\ of\ CO_2}{kWhr_{electin}}$$

Microturbine equation: uses heat recovery factor of 4.0 kBtu/kWhr

$$(CO_2)_{MTC} \cong \left(\frac{4.0\ kBtu}{kWhr_{ENGO}}\right)\left(\frac{0.7\,Btu_{in}}{Btu_{out}}\right)\left(\frac{0.634\ kWhr_{ENGO}}{ton\ of\ cooling}\right)\left(\frac{ton\ of\ cooling}{12\ kBtu}\right)\left(\frac{lb\ of\ CO_2}{kWhr_{elecin}}\right)$$

$$\cong \frac{0.15\ lbs\ of\ CO_2}{kWhr_{electin}}$$

IC Engine equation: uses heat recovery factor of 2.8 kBtu/kWhr

$$(CO_2)_{ICEC} \cong \left(\frac{2.8\ kBtu}{kWhr_{ENGO}}\right)\left(\frac{0.7\,Btu_{in}}{Btu_{out}}\right)\left(\frac{0.634\ kWhr_{ENGO}}{ton\ of\ cooling}\right)\left(\frac{ton\ of\ cooling}{12\ kBtu}\right)\left(\frac{lb\ of\ CO_2}{kWhr_{elecin}}\right)$$

$$\cong \frac{0.10\ lbs\ of\ CO_2}{kWhr_{electin}}$$

Fuel Cell equation: uses heat recovery factor of 1.7 kBtu/kWhr

$$(CO_2)_{FCC} \cong \left(\frac{1.7\ kBtu}{kWhr_{ENGO}}\right)\left(\frac{0.7\,Btu_{in}}{Btu_{out}}\right)\left(\frac{0.634\ kWhr_{ENGO}}{ton\ of\ \ cooling}\right)\left(\frac{ton\ of\ \ cooling}{12\ kBtu}\right)\left(\frac{lb\ of\ \ CO_2}{kWhr_{elecin}}\right)$$

$$\cong \frac{0.06\ lbs\ of\ \ CO_2}{kWhr_{electin}}$$

Fully Adjusted CO_2 Emission Factors

The fully adjusted emission factors, when multiplied by the electricity generated at cogeneration sites represents the net change in GHG emissions due to the existence of the SGIP program. The equation for the adjusted emission factor is:

Fully adjusted CO_2 *EF = (Base*CO_2 EF_{it} *– SGIP*CO_2 EF_a *+* HRF_a *+ CHFa)*electricity*$_j$
where:

> *i = NC or SC*
> *t = hour*
> *a = technology type*
> *j = facility*