CPUC Self-Generation Incentive Program Sixth Year Impact Evaluation Draft Report

Submitted to:

PG&E
and
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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.

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 sixth program year of the SGIP covering the 2006 calendar year. The evaluation covers all SGIP projects coming on-line prior to January 1, 2007. The evaluation examines impacts or requirements associated with energy delivery; peak demand; efficiency and waste heat utilization; transmission and distribution; and greenhouse gas emission reductions.[2] Impacts are examined at the program-wide level, and at a technology-specific level, depending on the nature of the reported result.

A number of DG technologies receive rebates under the SGIP. Rebates are provided in accordance with incentive level. Because incentive levels and the groupings of technologies that fall within them have changed over time, this report will summarize results by technology and fuel type instead of incentive level, which was used in the previous impact reports. Table 1-1 summarizes the SGIP technology groups that are used in this report.

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

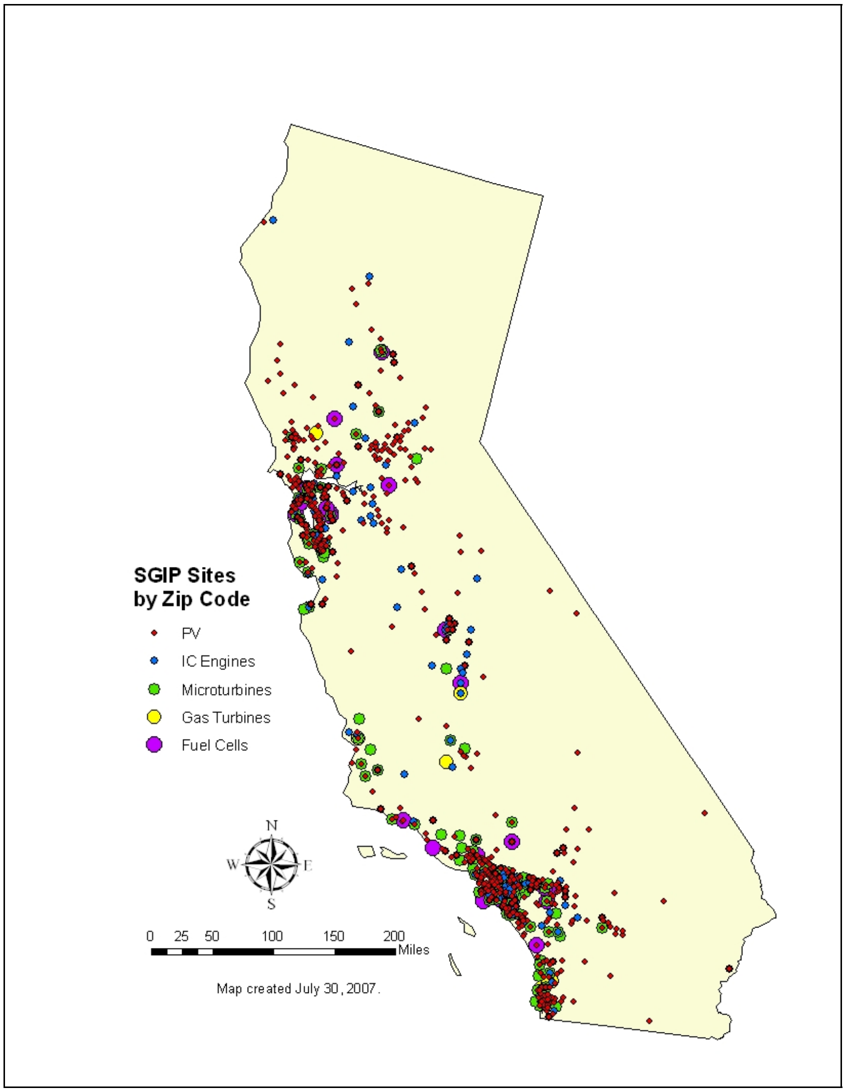
2 The 2005 Impacts Evaluation Report contained an update on compliance of projects using renewable fuels (e.g., biogas) to comply with renewable fuel use requirements set forth by the CPUC. However, based on direction from the Working Group and the Project Manager, renewable fuel use compliance will be reported only in the Renewable Fuel Use Reports filed semiannually with the CPUC.

Table 1-1: SGIP Eligible Technologies

Eligible Generation Technologies	
Photovoltaics (PV)	Wind Turbines (WD)
Nonrenewable-fueled microturbines (MT-N)	Non-renewable fuel cells (FC-N)
Renewable-fueled microturbines (MT-R)	Renewable fuel cells (FC-R)
Nonrenewable-fueled gas turbines (GT-N)	Nonrenewable-fueled internal combustion engines (ICE-N)
Renewable-fueled gas turbines (GT-R)	Renewable-fueled internal combustion engines (ICE-R)

The SGIP stretches over the service territories of the three major investor owned utilities (IOUs) in California as well as a number of municipal electric utilities. Figure 1-1 shows the distribution of SGIP facilities across California by type of technology.

Figure 1-1: Distribution of SGIP Facilities



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 2006, there were 948 projects on-line representing over 233 megawatts (MW) of rebated generating capacity. SGIP projects are distributed among SGIP PAs as shown in Table 1-2.

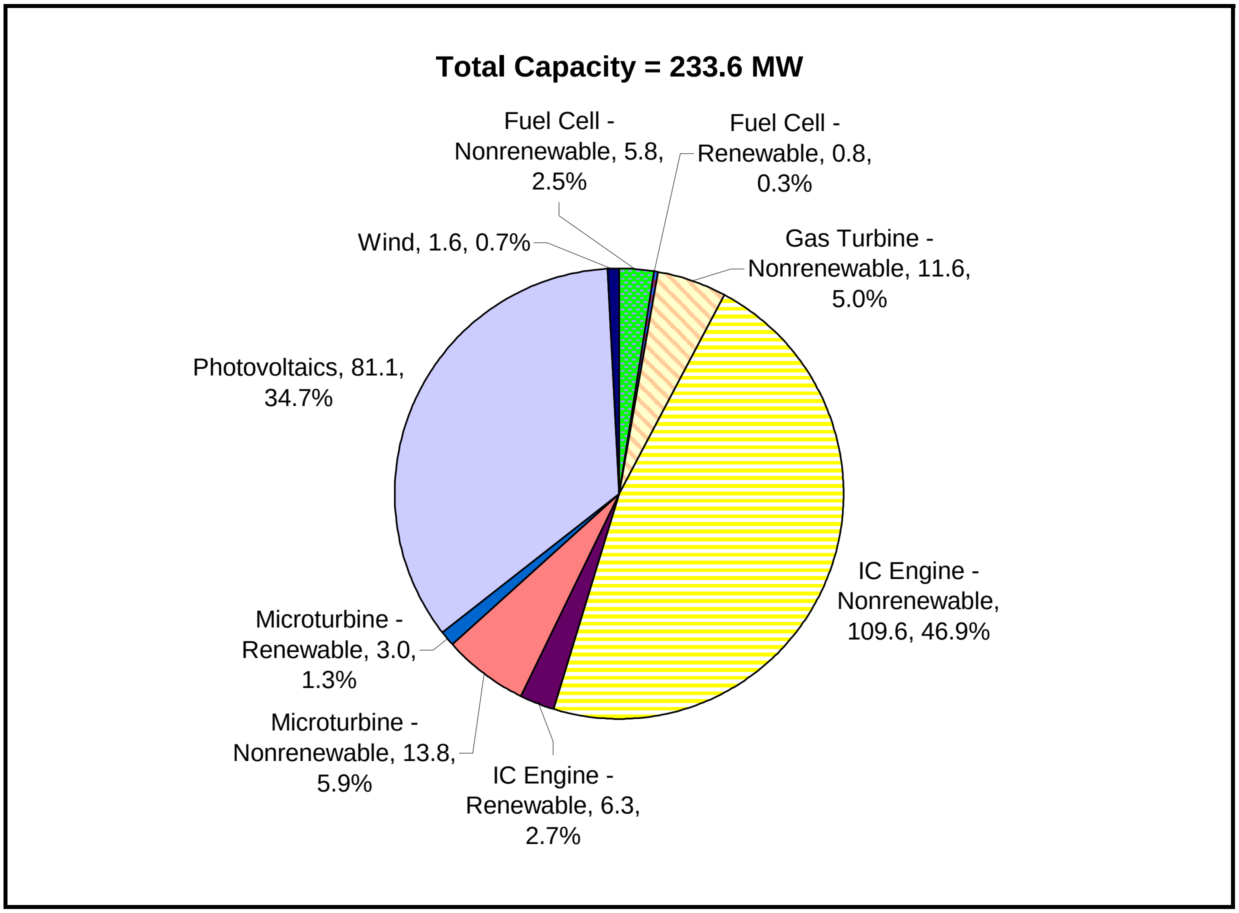
Table 1-2: Distribution of Projects and Rebated Capacity among PAs as of 12/31/06

PA	No. of Projects	Capacity (MW)	% of Total Capacity
PG&E	439	105.1	45
SCE	244	46.2	20
SoCalGas	146	55.5	24
CCSE	119	26.8	11
Totals	**948**	**223.6**	**100**

The capacity of Complete[3] projects increased 23 percent (56 MW) from 2005 to 2006. PV systems installed between 2005 to 2006 contributed 28 MW of capacity; or approximately half of the growth of the SGIP during this period. Most of the remaining growth in capacity from 2005 to 2006 came from microturbines and IC engines. Wind and fuel cell systems had little, if any, growth during this same period. Figure 1-2 shows the generating capacity distribution by technology and fuel at the end of 2006.

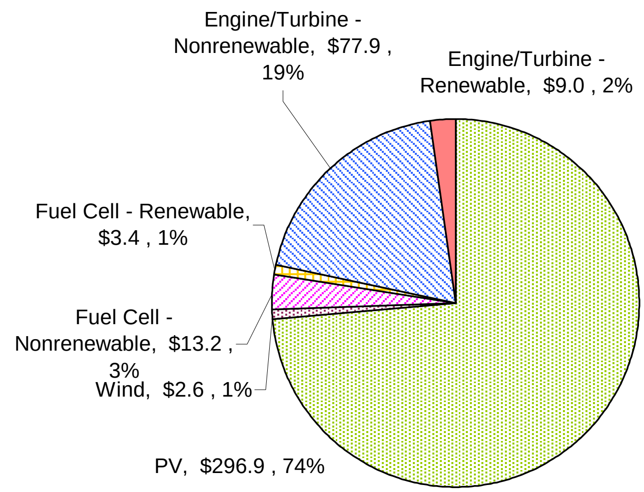
3 Complete projects are defined as those projects that are on-line and had received an SGIP incentive check

Figure 1-2: SGIP Capacity (MW) by Technology and Fuel Type as of 12/31/06



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 increased substantially between 2005 and 2006 (from $273 million to $403 million). Over 70 percent of incentives have been paid to PV projects. Figure 1-3 shows the distribution of incentives paid by incentive level as of the end of 2006. 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 exceeding $1 billion.

Figure 1-3: Incentive Payments by Technology and Fuel Type as of 12/31/06 ($Millions)



Energy and Demand Impacts

During PY06, SGIP projects delivered over 610,000 MWh of electricity to California's grid. SGIP projects are located at customer sites of the IOUs[4] to help meet on-site demand. Consequently, the 610,000 MWh of electricity provided by SGIP facilities represented electricity that did not have to be generated by central station power plants and delivered by the transmission and distribution system.

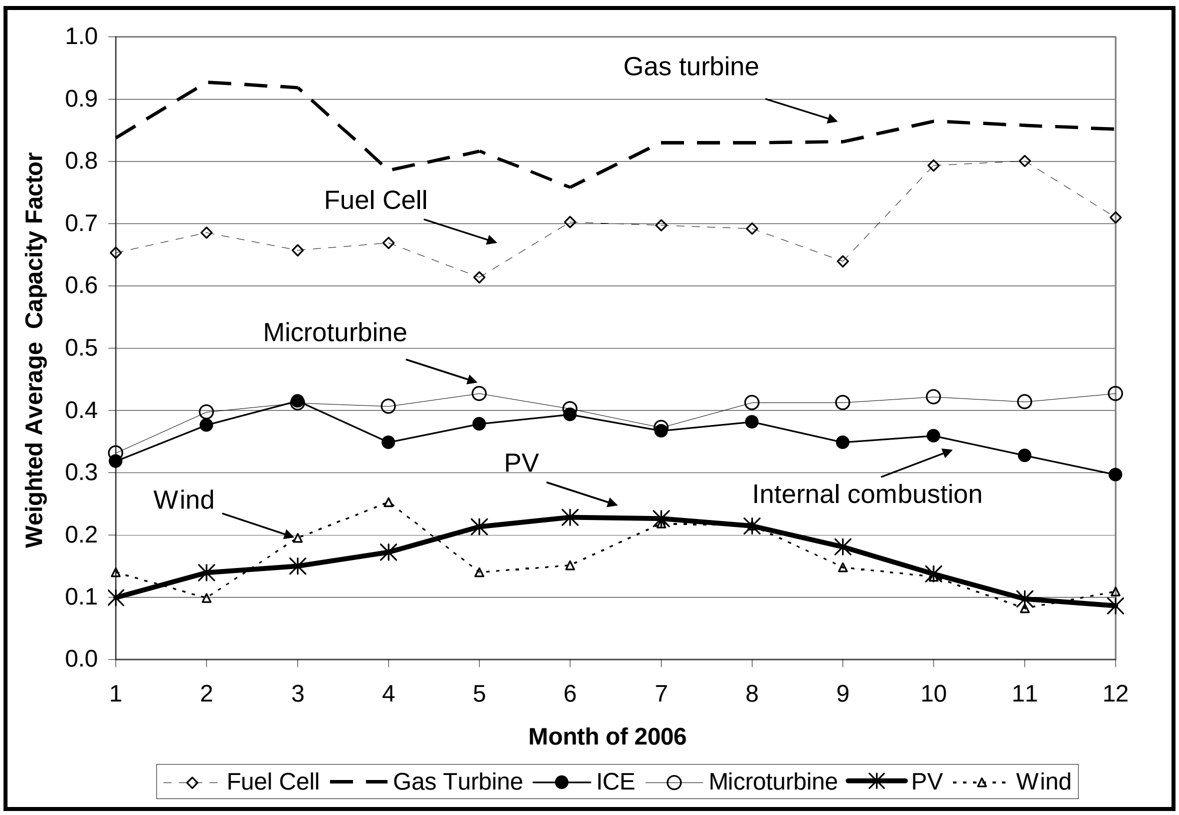
Thermal cogeneration systems (fuel cells, engines, and turbines) provided over 80 percent of the electricity delivered by SGIP facilities during 2006. PV projects supplied the next largest amount at approximately 17 percent of the total.

For purposes of this report, capacity factor is used as a measure of electricity deliverability. It represents the proportion of the rebated generating capacity which can be delivered by a

[4] Although rebated through the SGIP, approximately 9 percent of SGIP facilities are located at customer sites of municipal electric utilities.

project over a specific time period. For example, an 80 percent June average capacity factor for fuel cells would indicate that every 100 kW of rebated fuel cell capacity would, on average, provide 80 kW of generating capacity during June. Figure 1-4 shows monthly weighted average capacity factors of SGIP technologies throughout 2006 based on measured performance of SGIP technologies. Overall, natural gas turbines demonstrated the highest capacity factor, generally ranging from slightly below 0.8 to slightly above 0.9. Fuel cell capacity factors are lower than for gas turbines, but this is primarily an artifact of the lowering of capacity factor by fuel cells using biogas fuels.[5] As was observed in the 2005 Impacts Evaluation Report, microturbines and IC engines exhibited capacity factors ranging from 0.3 to 0.45; significantly lower than capacity factors for fuel cells and gas turbines. Due to the intermittent nature of their renewable resource supplies, wind and PV projects had monthly capacity factors ranging from slightly less than 0.10 to over 0.20.

Figure 1-4: Weighted Average Capacity Factor by Technology and Month (2006)



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5 Fuel cell capacity factor increases to approximately 0.8 when examining only natural gas powered fuel cells. Impacts of biogas use in fuel cells is discussed more thoroughly in section 5.

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 dispatch older and more expensive 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 PY06 were estimated by looking at SGIP contributions coincident with the California Independent System Operator (CAISO) 2006 system peak load. The system reached a peak of 50,198 MW on July 24, 2006, from 3:00 to 4:00 P.M. Total SGIP project capacity coincident with the peak was estimated at over 103 MW, representing an aggregate SGIP capacity factor of roughly 0.47 at CAISO system peak. Slightly less than half of this impact came from internal combustion engines. PV systems accounted for 37 percent. Figure 1-5 depicts the impact of SGIP projects on the 2006 system peak.

Figure 1-5: SGIP Project Impacts on 2006 System Peak Technology

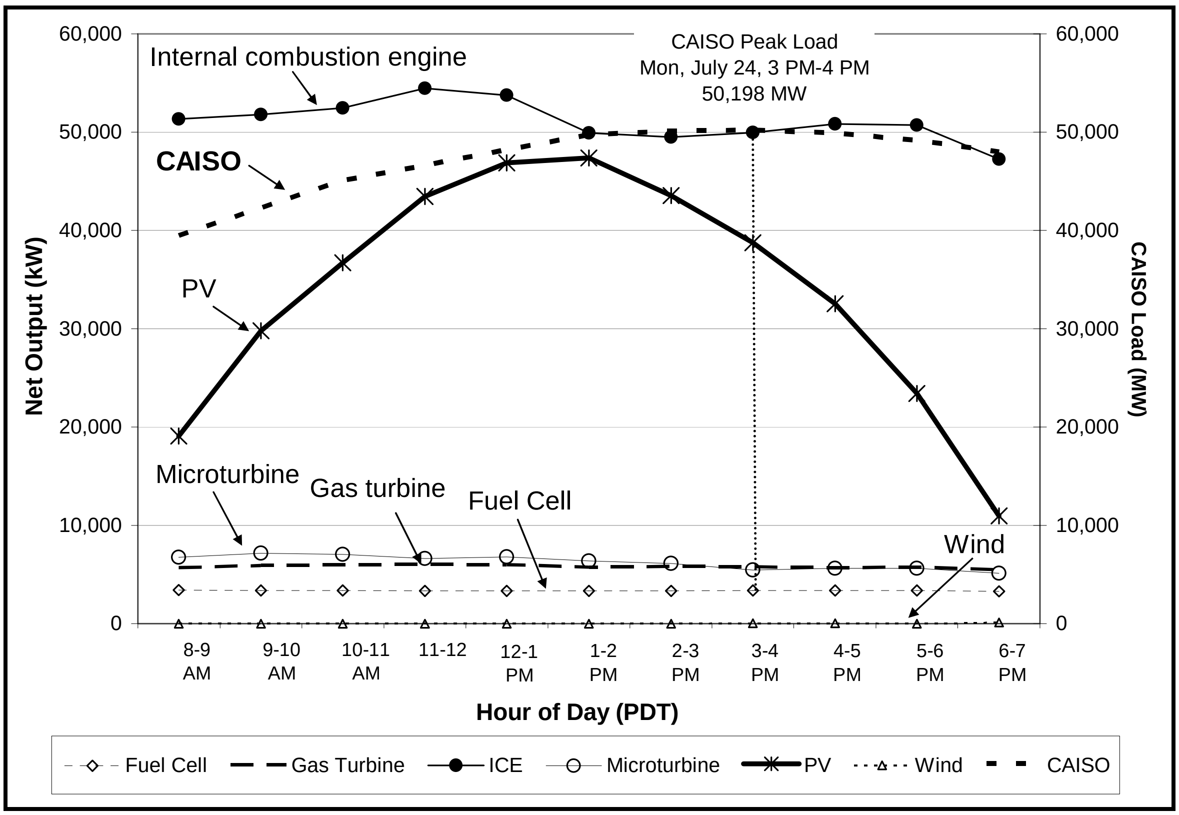


Table 1-3 provides a breakdown of SGIP impact on coincidence peak by technology type. The Impact column refers to the generating kW capacity at the peak hour. The Operational column refers to the total kW capacity potentially available at that time.[6] The Hourly Capacity Factor is the weighted average ratio of impact to operational capacity. The relatively low hourly capacity factor of 0.51 for PV is a result of the late afternoon timing of the CAISO system peak.

Table 1-3: Breakout of SGIP Project Impact on 2006 Coincident Peak

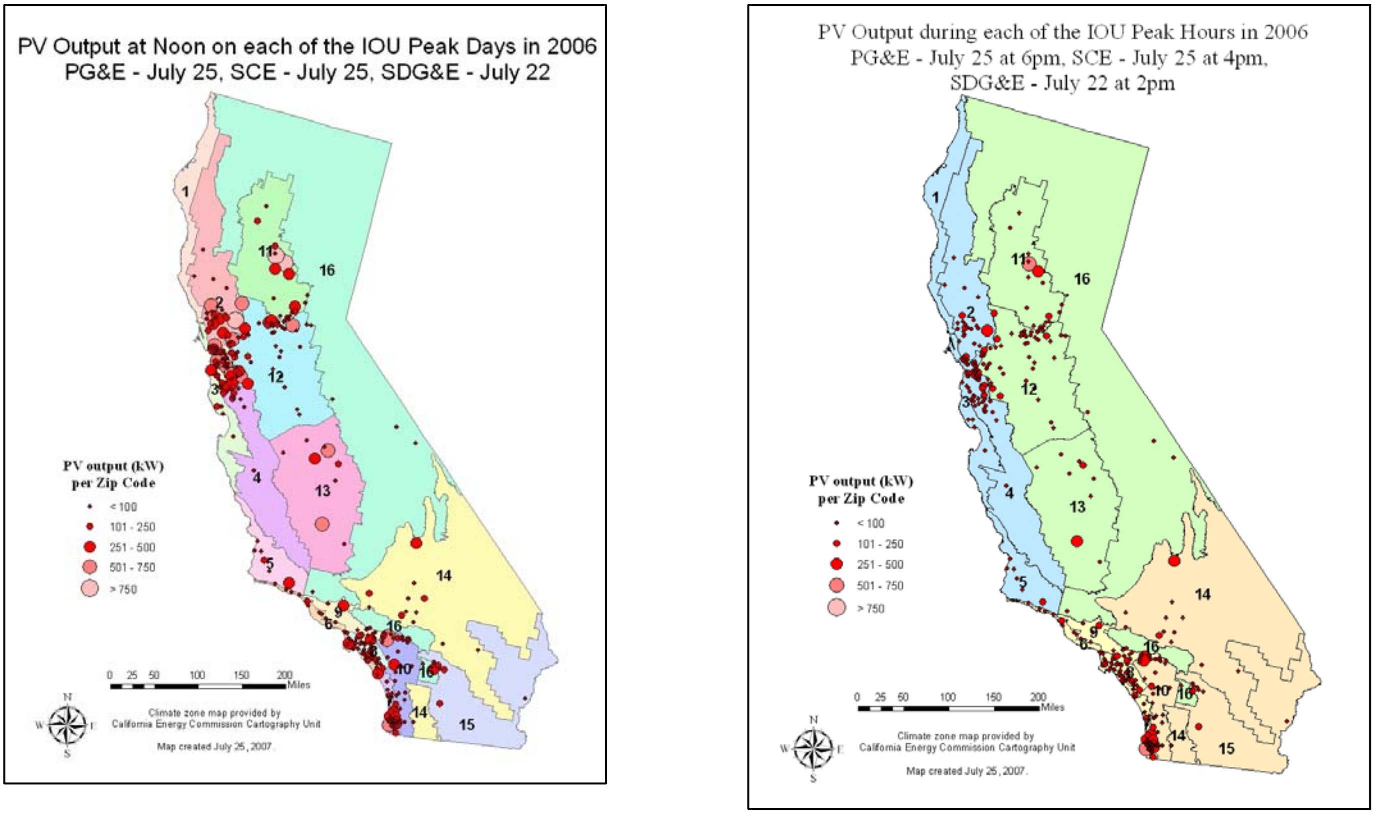
Technology	On-Line Systems (n)	Operational (kW)	Impact (kW)	Hourly Capacity Factor* (kWh/kWh)
FC	8	4,800	3,372	0.703 [a]
GT	3	7,093	5,789	0.816 †
ICE	185	116,184	49,942	0.430 [a]
MT	98	16,182	5,465	0.338 [a]
PV	609	75,808	38,744	0.511 [a]
WD	2	1,649	53	0.032
TOTAL	**905**	**221,715**	**103,365**	

* [a] indicates confidence is less than 70/30. † indicates confidence is better than 70/30. No symbol indicates confidence is better than 90/10.

As indicated earlier, nearly half of the growth in capacity in the SGIP in PY06 came from PV systems. The capacity factor for PV is strongly influenced by the amount of solar resource available at the time. PV output increases over the course of the morning, generally peaks around noon and then decreases as the sun sets. As a result, the contribution of PV to the utility peak demand is affected by the timing of the peak. Figure xx illustrates the impact of timing of peak demand on PV's ability to provide capacity. Larger circles represent a higher capacity of PV. The figure on the left shows PV capacity at noon. The figure on the right shows PV capacity at the time of peak demand during 2006 for each of the IOUs. As shown, PG&E's PV capacity at its 6 pm peak is significantly less than its PV capacity at noon. Conversely, there is little difference in PV capacity for SDG&E, which had its 2006 system peak at 2 pm.

6 This differs from the total installed capacity of 223.6 MW because at the time of system peak not all systems had been brought online.

Figure 1-6: Impact of Peak Demand Time of Day on PV Capacity



Transmission and Distribution Impacts

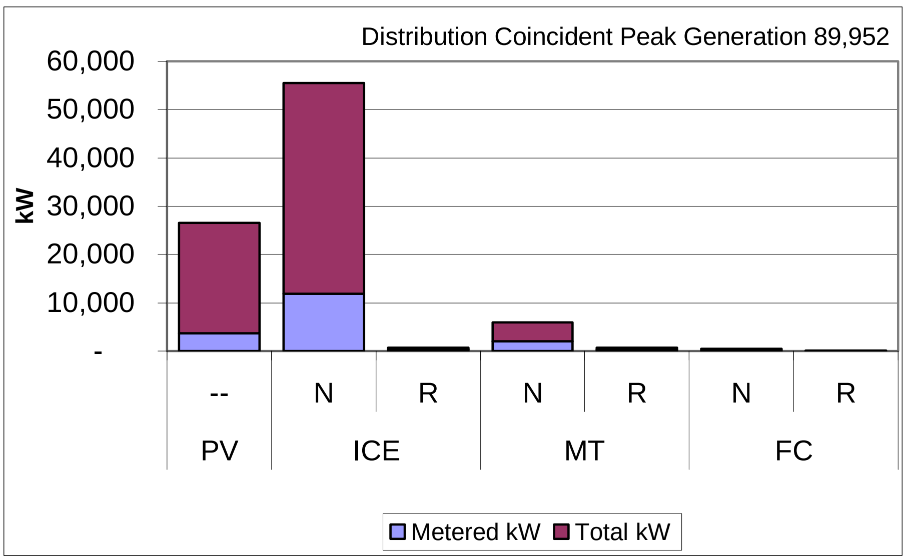
Peak hour capacity factors indicate the ability of a generation technology to provide electricity to the grid during times of peak demand, when that electricity is most needed. However, peak capacity factor cannot provide information on the ability of the generated electricity to actually enter the grid or defer generation from being delivered to a customer site. The ability of electricity to move along the transmission and distribution system depends largely on line loadings. If a distribution or transmission line is heavily loaded, there will be problems in moving additional electricity along the line. One of the anticipated benefits of DG technologies is their potential to reduce transmission and distribution line loadings by providing electricity directly at the demand source. This capability can be especially beneficial during times of peak demand when heavy electricity flow along the T&D system causes line congestion which can result in line overloading and outages.

Distribution System Impacts

Distribution system impacts were assessed by comparing SGIP facility hourly generation profiles against hourly distribution line loadings. Line loadings were limited to those distribution lines serving utility customers hosting SGIP DG facilities. In addition, line loadings used in the analysis represented the peak loading for the individual feeders occurring at the day and hour of the peak loading of that feeder. It is important to recognize that peak loading on feeder lines will often occur on different days and hours from the individual IOU system peaks and the CAISO system peak.

The estimated distribution peak load reduction associated with SGIP technologies in 2006 in the three utility service territories was 46.1 MW for PG&E; 37.1 MW for SCE; 6.8 MW for SDG&E; representing a statewide total of 90.0 MW. Figure 1-7 provides a summary of the measured and estimated impact of SGIP technologies on the distribution system in 2006.

Figure 1-7: Distribution System Peak Reduction by SGIP Technology (2006)



	PV --	ICE N	ICE R	MT N	MT R	FC N	FC R
Metered kW	3,636	11,914	360	2,024	203	0	0
Total kW	26,516	55,515	744	5,975	688	467	67
Metered #	78	55	3	28	4	1	1
Total #	569	165	9	81	16	9	2

The greatest distribution line reductions in 2006 were found to be associated with natural gas fueled IC engines; providing nearly 55 MW of peak distribution reduction. PV systems were found to provide the next largest distribution line reduction at nearly 26 MW; followed distantly by natural gas-fired microturbines at approximately 6 MW. Interestingly, fuel cells showed a negligible amount of distribution line peak reduction. However, that low reduction is likely due to the limited number of fuel cells operational during 2006 (less than 10 systems in the entire SGIP) and lack of distribution feeder loading data from the IOUs.

Distribution system planners investigating approaches to reduce distribution line peak loading from increased penetration of DG facilities will need a way to estimate the amount of peak reduction available from each DG technology. A "look-up" table that reports measured distribution coincident peak load reduction across the different SGIP technologies, utilities, feeder types and climate zones was developed for this purpose. Table 1-4 provides estimated peak coincident load reduction factors that can be used for distribution system planning. For example, afternoon peaking feeder lines (i.e., those feeder lines peaking before 4 pm) in the coastal zone of PG&E can expect to see a reduction factor of 0.56 for PV entering the distribution system. This means that, based on observed performance, every rebated kW of PV installed and operating in PG&E's coastal zone will effectively act to reduce the distribution line loading by 0.56 kW of peak loading. Similarly, when viewed statewide, PV technologies can be expected to provide 0.35 kW of peak reduction for every kW of rebated PV.

Table 1-4: Distribution Coincident Peak Reduction Factors

		PV	ICE		MT		FC	
		--	N	R	N	R	N	R
PG&E Coast	Afternoon	56%	85%					
	Evening	30%						
SCE Coast	Afternoon	46%	65%		44%			
	Evening	6%	48%		52%			
SDG&E Coast	Afternoon	42%	33%		40%			
	Evening	1%						
Inland	Afternoon	63%	29%					
	Evening	26%						
Total by Technology/Fuel		35%	50%	12%	50%	23%	16%	0%
Total by Technology		35%	48%		44%		9%	

Notes: Climate Zones

PG&E Coast (CEC Title 24 Climate Zones 2, 3, 4, 5)

SCE Coast (CEC Title 24 Climate Zones 6, 7, 8, 9, 10 in SCE service territory)

SDG&E Coast (CEC Title 24 Climate Zones 7, 8, 10 in SDG&E service territory)

Inland (CEC Title 24 Climate Zones 11, 12, 13, 14, 15 for all utilities)

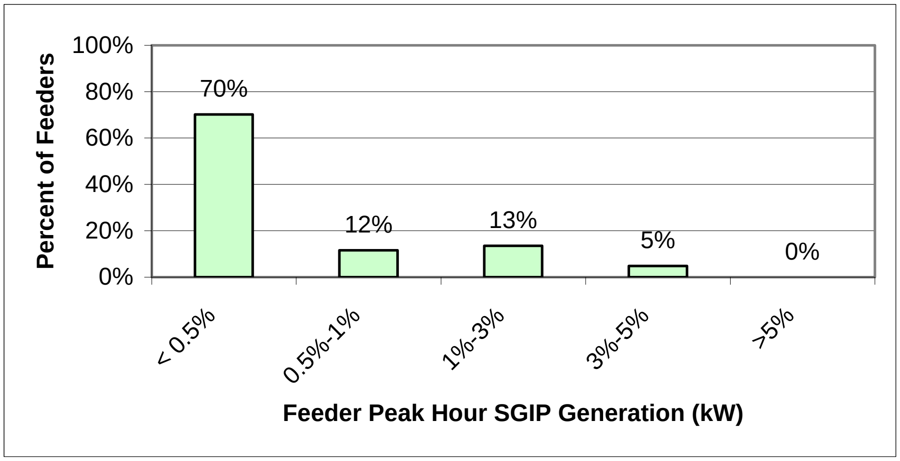
Distribution Peak Hour

Afternoon (Peak occurs on Hour Ending (HE) 16 or earlier)

Evening (Peak occurs after HE 16)

Based on the results in Table 1-4, SGIP technologies are seen to provide the potential for significant reduction in peak loading of the distribution system. However, high penetration of DG technologies will be needed to achieve significant overall reduction in peak loading across each IOU service territory. Table 1-5 provides a summary of the amount of peak reduction actually observed to occur in 2006 due to the impacts of SGIP technologies.

Table 1-5: Peak Reduction as Percentage of Feeders



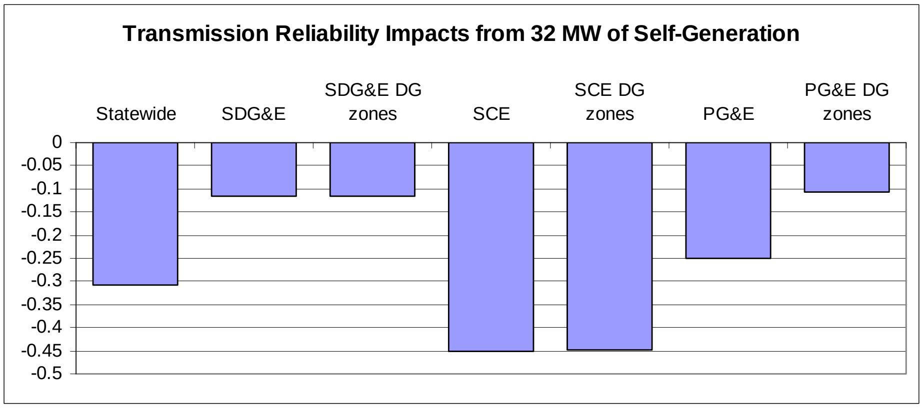
Overall, SGIP facilities had limited impact on reducing distribution system peak program-wide. No feeders or substations saw greater than five percent reduction of their peak loading. Approximately 70 percent of the feeders had peak loading impacts that were limited to less than 0.5 percent of the peak feeder loading. The low overall impact is attributable to the limited penetration of SGIP DG in the overall distribution system.

Transmission System Impacts

As load reduces due to self-generation on the distribution network, there is a corresponding reduction on distribution transformers, sub-transmission lines, transmission substations and ultimately on the high voltage lines. However, very high penetration of DG is generally considered necessary to provide significant benefits to the high voltage transmission lines.

Transmission system impacts were assessed by using measured SGIP generation and then modeling the aggregated capacity (MW) of SGIP DG facilities at each substation. Modeling of the transmission system focused on reliability impacts. In essence, the modeling simulated the impact on system reliability associated with removing SGIP generation out of the electricity system. A Distributed Generation Transmission Benefit Ratio (DGTBR) was calculated by the modeling approach and represents the net reliability impact. A negative DGTBR represents an improvement in system reliability. A positive DGTBR indicates a probable decrease in system reliability. Figure 1-8 is a summary of the reliability impacts associated with SGIP DG facilities during the summer 2006 peak.

Figure 1-8: Transmission Reliability Impacts for 2006 Peak



Overall, the power flow modeling results show that SGIP DG facilities improved system reliability at the transmission level. Statewide, each kW of rebated SGIP DG improved system reliability by 0.3 kW. Within each of the IOUs, SGIP facilities had the impact of improving system reliability from 0.1 to nearly 0.45 kW of increased reliability per kW of rebated SGIP capacity.

Even though the total aggregated capacity of the SGIP DG facilities represented only 32 MW out of the 42,000 MW of demand occurring under the 2006 summer peak conditions, the DG facilities were still found to provide overall DGTBR benefits to the system.

Efficiency and Waste Heat Utilization

Cogeneration facilities represent approximately two-thirds of the on-line generating capacity of the SGIP. Due to their large contribution to SGIP capacity, it is important that SGIP cogeneration facilities harness waste heat and realize high overall system and electricity efficiencies. In accordance with Public Utility Code (PUC) 216.6[7], fuel cells, IC engines, and turbine technologies powered by non-renewable fuels face certain minimum levels of thermal energy utilization and overall system efficiency. PUC 216.6(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 216.6(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

7 Public Utility Code 216.6 was previously PUC 218.5. The requirements have not changed.

useful thermal energy at projects on-line through the end of 2006 are summarized in Table 1-6.

Table 1-6: 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	182	69,935
Heating & Cooling	58	35,526
Cooling Only	28	20,673
To Be Determined	20	23,171
Total	288	149,305

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. The results are summarized in Table 1-7.

Table 1-7: Nonrenewable-Fueled Engine/Turbine Cogeneration System Efficiencies (n=288)

Technology	n	216.6 (a) proportion	216.6 (b) Efficiency	Overall Plant Efficiency
Fuel Cell	11	43%	55%	70%†
IC Engine	181	42%	39%	50%
Microturbine	96	50%	28%†	37%†

Metered and estimated data collected to date suggest that roughly 17 out of 288 cogeneration projects achieved the 216.6 (b) overall system efficiency target of 42.5%.

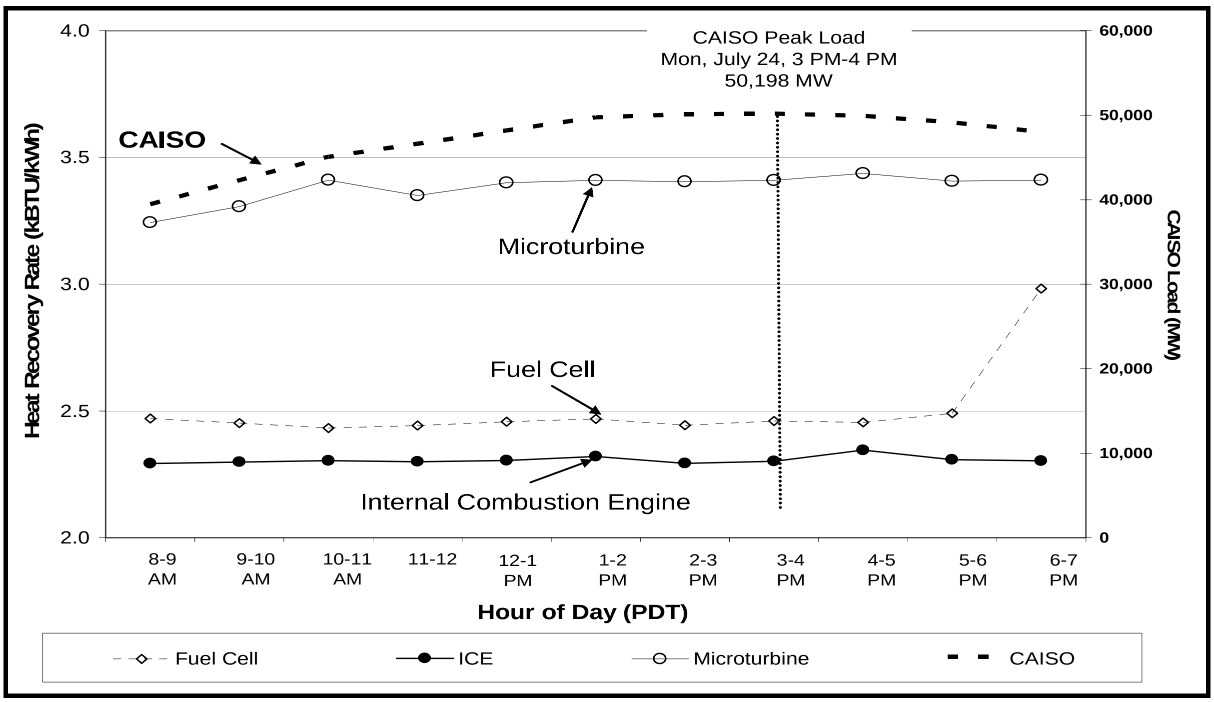
One possible explanation for the lower than expected efficiency results could be tied to low electricity efficiencies. Results of an analysis of SGIP cogeneration system electrical conversion efficiencies are presented in Table 1-8. In the case of reciprocating internal combustion engines (ICE), actual 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 1-8: Electrical Conversion Efficiency

Summary Statistic	Fuel Cells (FC)	Internal Combustion Engines (ICE)	Microturbines (MT)
n	11	181	96
Min	40%	0%	0%
Max	40%	35%	22%
Median	40%	29%	19%
Mean	40%	28%	18%
Std Dev	0%	4%	3%

The contribution of cogeneration systems during peak periods was developed for 2006. As the GHG and T&D portions of the analysis evolve hourly heat recovery results will become increasingly important. Figure 1-9 provides hourly heat recovery rates during the CAISO system peak day. As shown, the variability is relatively low during the day. Subsequent evaluations will attempt to incorporate additional metered points as well as an examination of base loading vs. load following facilities.

Figure 1-9: Heat Recovery Rate During CAISO Peak Day



Greenhouse Gas Emission Reduction Impacts

Greenhouse gas (GHG) emission reductions from SGIP facilities were investigated for the first time in the 2005 Impacts Evaluation Report. The approach used for calculating GHG reductions for PY06 remains essentially the same as used for PY05. However, GHG for PY06 are reported by technology type rather than by incentive level. This approach provides greater refinement of results and an increased understanding of the relationship between GHG reductions and fuel type. In addition, the focus on GHG emission reduction in the SGIP analysis has remained primarily on two gases: carbon dioxide (CO_2) and methane (CH_4) as these are the main contributors of GHG from SGIP facilities.

Table 1-9 is a summary of net reductions in GHG emissions attributable to SGIP facilities during PY06. The results are reported in tons of CO2 equivalent to allow comparison of contribution from the different SGIP technologies and with other GHG sources outside the SGIP.

Table 1-9: Net Reduction in GHG Emissions from SGIP Technologies (2006)

Technology	Tons of CO2 eq. Reduced	Annual Energy Impact (in MWh)	CO2 eq. Factor (Tons/MWhr)
Photovoltaics	62,253	103,306	0.60
Wind turbines	1,265	2,102	0.60
Non-renewable fuel cells	5,241	26,170	0.20
Non-renewable MT	-7,866	47,202	-0.17
Non-renewable fueled ICE	5,798	353,436	0.02
Non-renewable and waste gas fueled small gas turbines	4,333	55,287	0.08
Renewable fueled fuel cells	5,193	2,498	2.07
Renewable fueled MT	34,087	9,281	3.67
Renewable fueled IC Engines	9,020	10,233	0.88
TOTAL	**119,324**	**609,515**	**0.20**

PV systems accounted for over half of the GHG emission reductions from SGIP facilities in PY06. Biogas fueled SGIP facilities provided over 48,000 tons per year of CO_2 equivalent reductions; representing slightly over 40 percent of the total GHG reductions. Non-renewable cogeneration facilities combined provided a net reduction of approximately 7,500 tons of CO_2 equivalent reductions; or approximately six percent of the overall GHG reductions.

There are three major sources of GHG emission reductions from SGIP facilities:

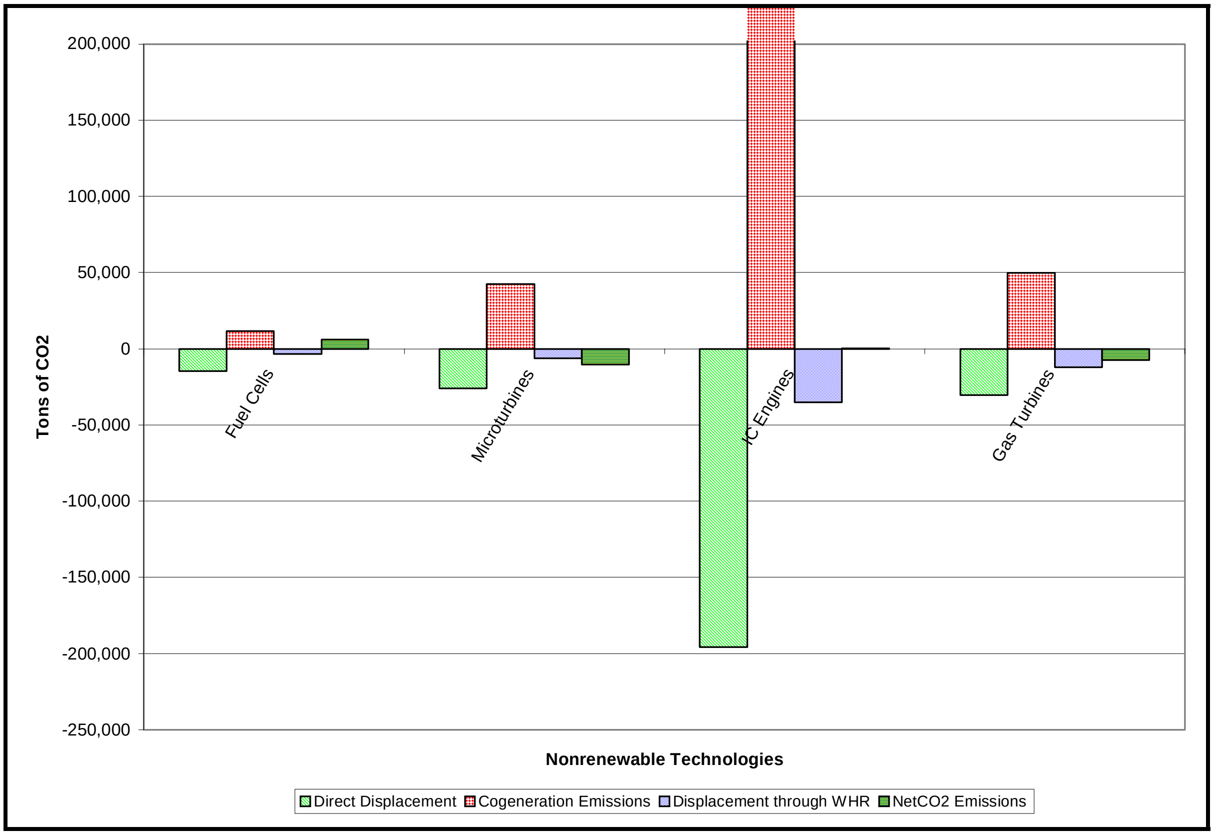
1. Net differences in CO_2 emissions resulting from electricity supplied to utility customers from central station generation facilities versus electricity supplied by the customer's own SGIP generator (i.e., "direct displacement");
2. Net CO_2 emission reductions due to waste heat recovery systems used at SGIP facilities and which either displaced natural gas otherwise used to produce process

heat or displaced electricity normally supplied from central station generation facilities to drive electrical chillers ("displacement through waste heat recovery"); and

3. Methane captured and used by biogas-fired SGIP facilities.

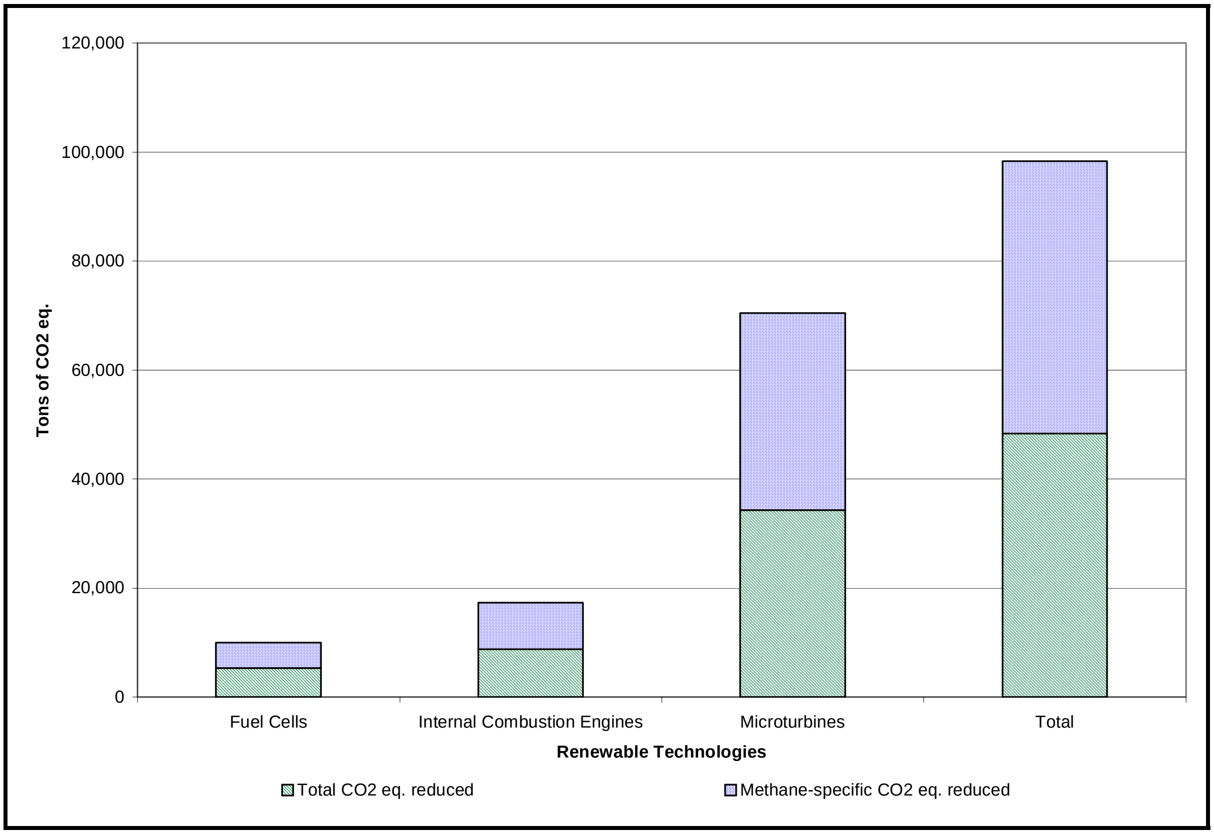
The importance of waste heat recovery on CO_2 reductions for non-renewable cogeneration facilities is illustrated in Figure 1-10. In general, CO_2 emissions from direct displacement of grid provided electricity are essentially zeroed out the CO_2 emissions from the SGIP generator. CO_2 emission reductions from waste heat recovery provide a net reduction in CO_2 emissions for non-renewably fueled microturbines, IC engines and gas turbines.

Figure 1-10: Breakdown of CO2 Sources for Non-Renewable Cogeneration Technologies in the SGIP (2006)



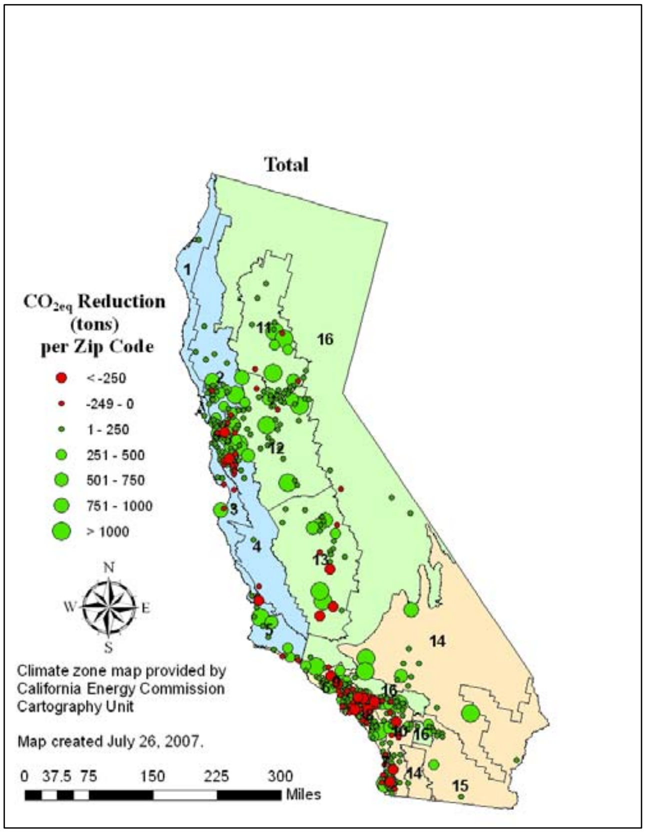
The contribution of captured and harnessed methane in biogas-fueled SGIP facilities is shown in Figure 1-11. Nearly half of the GHG reductions from biogas-fueled SGIP facilities in 2006 were due to the capture and use of methane derived from such biogas sources such as diaries and landfills.

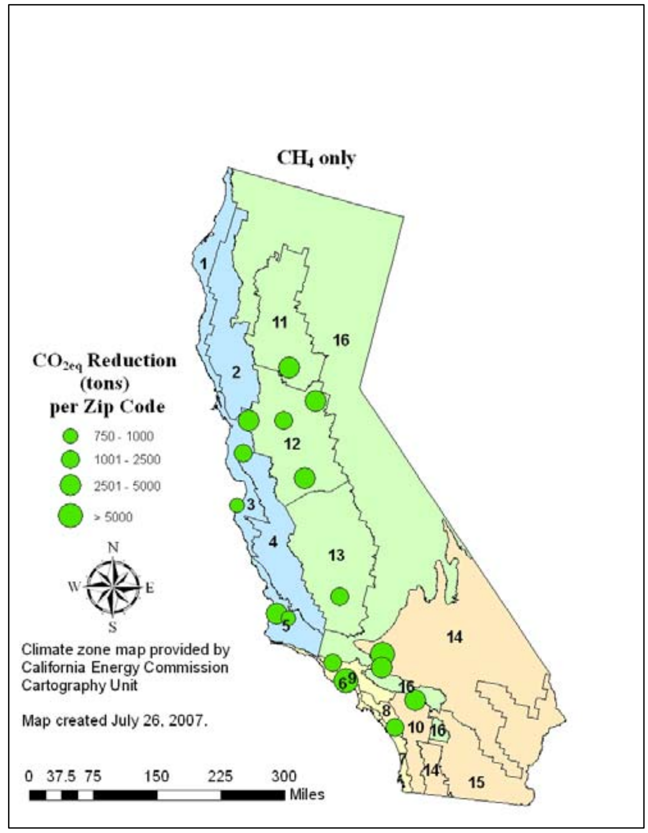
Figure 1-11: Contribution of Methane to Overall GHG Reductions in Biogas Fueled SGIP Technologies (2006)



Due to the increasing role of GHG emission reductions, it is also important to identify the distribution of GHG reductions within the SGIP. Figure 1-1 shows the distribution of GHG emission reductions due to SGIP facilities throughout California. The figure on the left depicts the total GHG reductions from all sources within the SGIP facilities. The figure on the right shows only the locations of those biogas fueled SGIP facilities providing methane based GHG reductions.

Figure 1-12: Distribution of GHG Emission Reductions Among SGIP Facilities (2006)



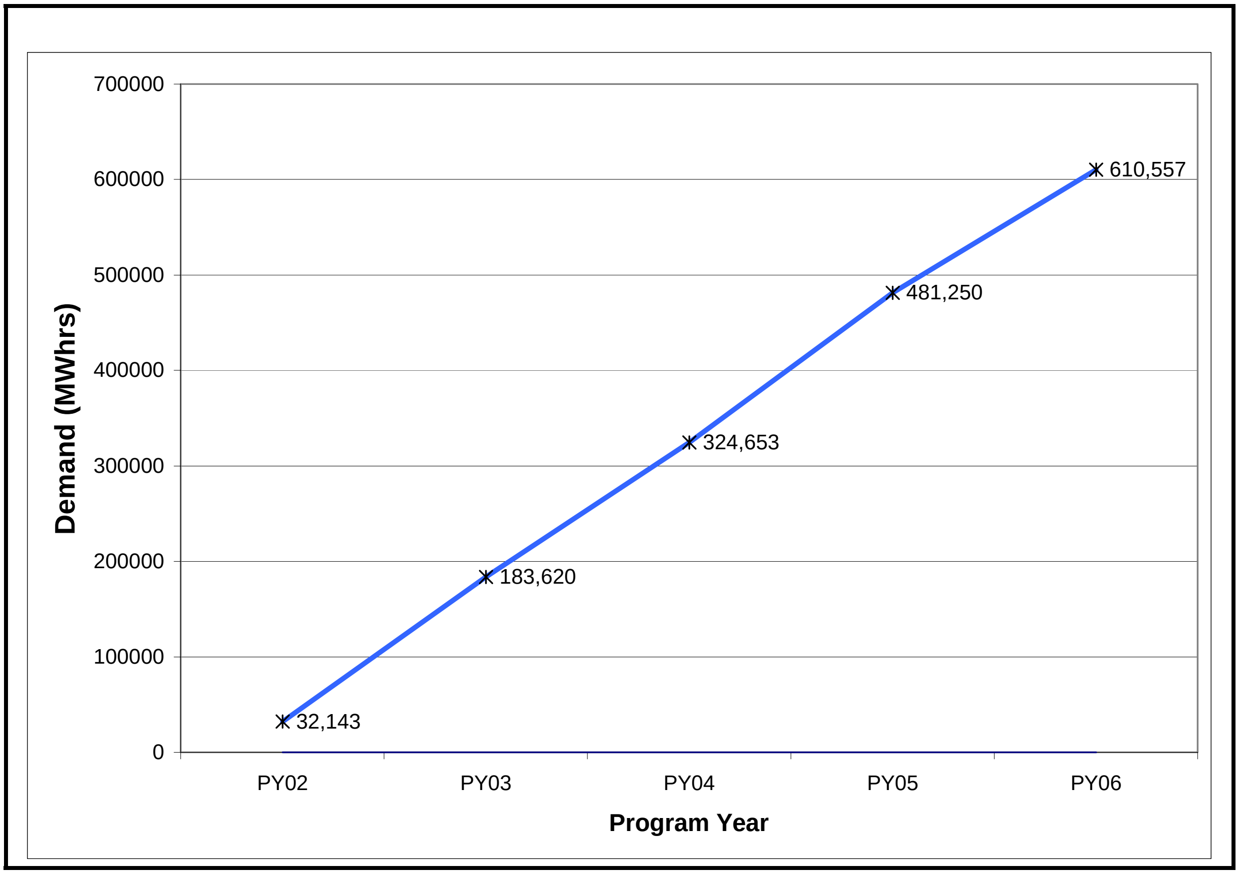


1.3 Trends on Program Impacts

Energy

The ability of the SGIP to deliver energy has steadily increased since inception of the program. Figure 1-13 shows the increase in the amount of electricity delivered by SGIP projects annually from 2002 through the end of 2006. From 2003 on, annual electricity delivered by the SGIP has increased by over 125 percent each year.

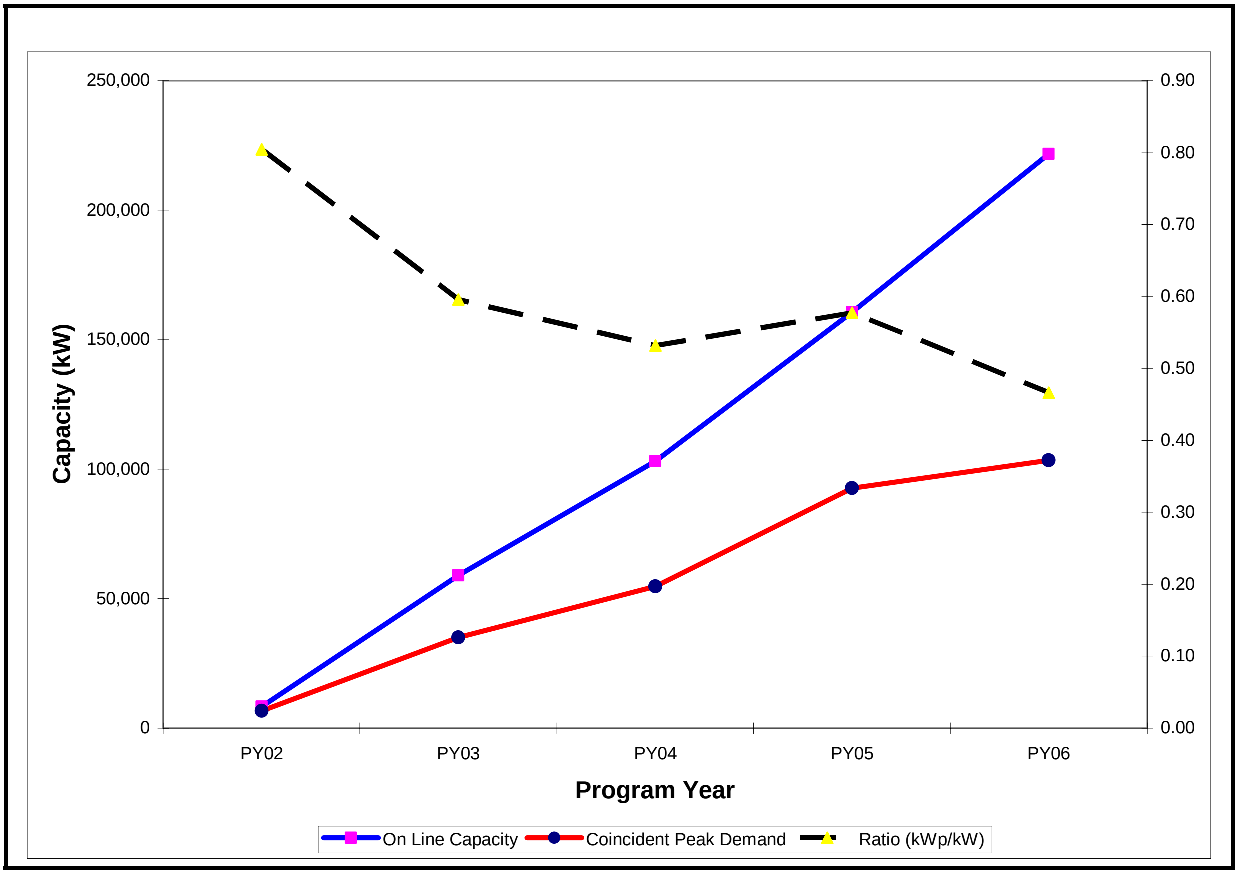
Figure 1-13: Trend in SGIP Energy Delivery from 2002 to 2006



Coincident Peak Demand

Figure 1-14 shows the change in coincident peak demand that has occurred from PY02 through the end of PY06. 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 0.3 to 0.4 for the last two years. 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 1-14: Trend on Coincident Peak Demand from PY02 to PY06

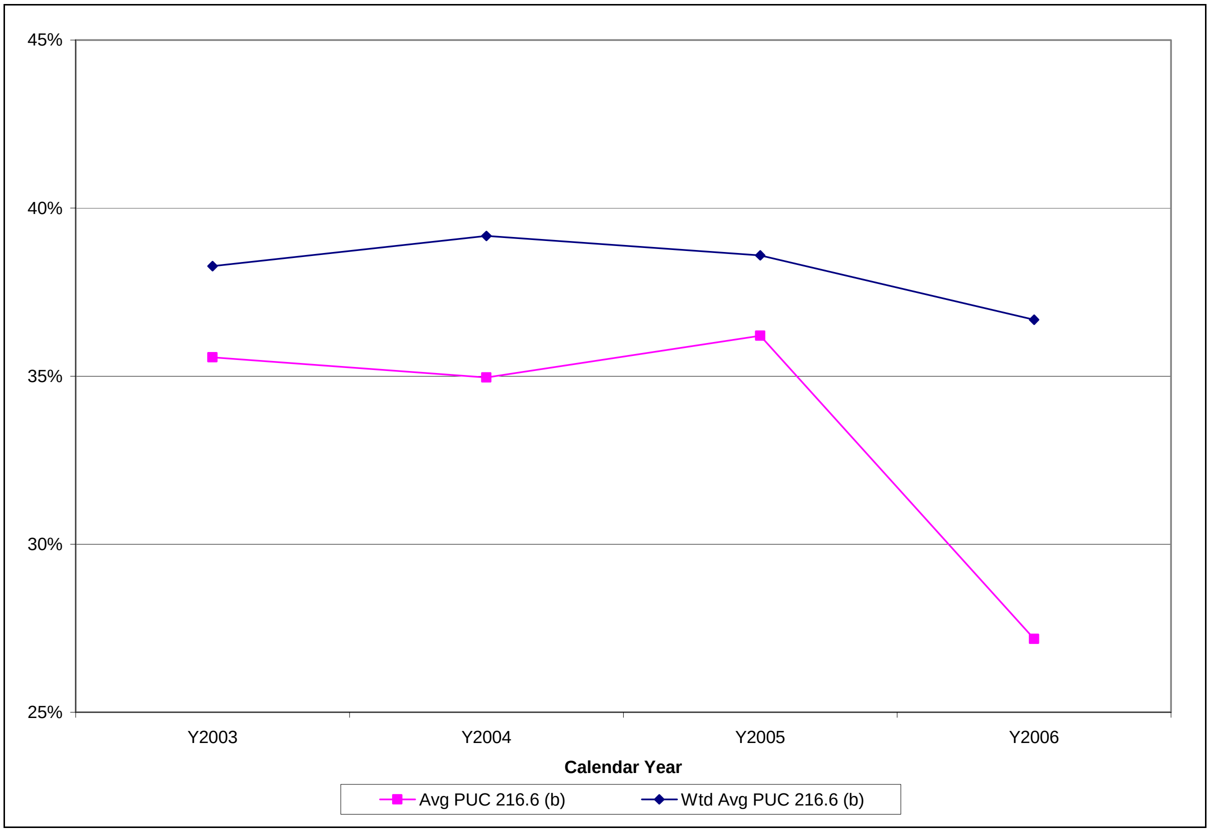


System Efficiency

Cogeneration facilities have been monitored for several years under this evaluation. Although the number of facilities monitored is relatively small, the resulting efficiencies are representative of many other systems. Figure 1-15 provides a trend of PUC 216.6 (b) efficiency from 2003 through 2006. The noticeable dip in efficiency in 2006 may be explained by several possible issues. First, the 2006 analysis includes all completed systems since program inception. Some of these systems are reaching the end of their life and are being decommissioned. Others are operating at part load and are experiencing efficiency issues as a result. Finally, some systems are experiencing heat recovery issues, such as failed heat exchangers, but continue to operate the generating equipment.

The difference between average and weighted average PUC 216.6 (b) efficiencies is a result of larger systems generally operating better than smaller systems. This is due to any number of reasons including dedicated O&M staff, more thoughtful engineering design, a preventive maintenance program, or a more reliable and consistent use for the waste heat.

Figure 1-15: Trend of PUC 216.6 (b) (2003-2006)



1.4 Looking Forward: Opportunities and Challenges

The SGIP represents tremendous opportunities for California and California's utilities. It represents a wealth of experience and knowledge about the deployment and operation of DG facilities in a utility environment. California, like many other states, is poised to move forward into an era of potentially rapid growth in DG. Although DG facilities currently represent less than 2.5 percent of California's peak demand, the California Energy Commission anticipates that by 2020, DG facilities will provide enough electricity to meet nearly 25 percent of California's peak demand.[8] The knowledge gained by the SGIP can be critical in helping California meet this goal.

California is also looking at making significant strides in reducing GHG emissions. In accordance with the Global Warming Solutions Act of 2006 and Executive Order S-3-05 from the Governor, California is to reduce GHG emissions to 1990 levels by 2020. Insights gained from the SGIP on the role of DG facilities will help California not only move forward in meeting the GHG targets but will concurrently help address the role to be played by increased penetration of DG technologies.

Several important challenges face the SGIP as it moves into the future. Under Assembly Bill 2778, approved in September of 2006, eligibility of SGIP technologies may be limited to "ultra-clean and low emission distributed generation" technologies, such as wind and fuel cells. Currently, nearly 65 percent of the SGIP's capacity is based on cogeneration technologies; with the remaining 35 percent based on PV systems. PV technologies have already moved out of the SGIP into the California Solar Initiative Program. The cogeneration portion of the SGIP is dominated by IC engines and microturbines. IC engines and microturbines make up nearly 97 percent of the number of cogeneration facilities and 95 percent of the capacity of cogeneration systems installed under the SGIP. However, both IC engines and microturbines have experienced difficulties in achieving compliance with prescribed NO_x requirements and PUC 216.6 energy efficiency requirements. Due to the higher cost of fuel cell technologies and issues facing wind integration, replacement of cogeneration technologies with wind and fuel cell technologies could take time and pose additional problems. For example, the GHG reduction findings and an earlier cost-effectiveness study[9] conducted on the SGIP indicates that it may be beneficial for the program to focus more effort on deploying biogas powered cogeneration facilities. However, a number of technical and cost issues will need to be resolved for fuel cells to use biogas fuels competitively against IC engines and microturbines. For these reasons, there will need

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8 California Energy Commission, "Distributed Generation and Cogeneration Roadmap for California," CEC-500-2007-021, March 2007

9 Itron for the CPUC, "CPUC Self-Generation Incentive Program Preliminary Cost-Effectiveness Evaluation Report," September 8, 2005

to be a greater understanding of the relationships between NO_x emissions, GHG reductions and the efficiencies of DG cogeneration technologies that may participate in the SGIP in the future.

As California expands use of DG technologies, they will play a larger role in meeting peak demand. This 2006 Impacts Evaluation Report begins to shed light on the interplay between DG technologies, peak loading on distribution feeders, higher voltage transmission lines and overall system peak. However, making a smooth and cost-effective increased deployment of DG technologies into California's grid requires additional understanding of the T&D impacts.

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, microturbines, 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 California Energy Commission (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 were made in 2004 and 2007. For example, with the funding of the California Solar Initiative (CSI), the SGIP no longer offered incentives to photovoltaic (PV) systems after 2006. Similarly, AB 2778, approved in September of 2006, continues the SGIP through 2012, but limits eligibility to "ultra-clean and low emission distributed generation" technologies, such as wind and fuel cells. It is uncertain what role, if any, other renewable energy technologies, such as biogas-fueled or micro-hydropower systems will play in the SGIP after 2007. Moreover, cogeneration systems were no longer funded beyond 2007 under AB 2778. 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.

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

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 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, 2006, over $822 million in incentives had been paid out through the SGIP, resulting in the installation of nearly 947 DG projects representing approximately 233 megawatts (MW) of rebated capacity.

2.2 Impact Evaluation Requirements

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 2006.

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
2005[6]	March 1, 2007

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.

6 California Self-Generation Incentive Program: Fifth Year Impact Evaluation Report. Submitted to Pacific Gas & Electric. Prepared by Itron, Inc., March 1, 2007.

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 impact evaluation reports through 2008. Table 2-2 identifies the schedule for filing of the 2006 through 2008 impact evaluation reports.

Table 2-2: Post-2006 SGIP Impact Evaluation Reports

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

This report provides the findings of an impact evaluation of the sixth program year of the SGIP covering the 2006 calendar year.

2.3 Scope of the Report

The 2006 Impact Evaluation Report represents the sixth 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 2006 report examines the effects of SGIP technologies on electricity production and demand reduction at different times, on system reliability and operation, and on compliance with renewable fuel use and thermal energy efficiency requirements. In addition, the 2006 report also examines greenhouse gas emission reductions associated with each SGIP technology category and impacts on transmission and distribution (T&D) system operation and reliability.

Table 2-3 summarizes the impact evaluation objectives contained in the 2006 report.

Table 2-3: Impact Evaluation Objectives in 2006 Report

Impact Evaluation Objectives Addressed in 2006 Impact 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 across technologies and by individual technology category
Compliance of fuel cell, internal combustion engine, microturbine, and gas turbine technologies will be assessed against PUC 216.6[7] requirements ■ PUC 216.6 (a): useful recovered waste heat requirements ■ PUC 216.6 (b): system efficiency requirements
Transmission and distribution impacts ■ Distribution system impacts at the PA and program-wide level ■ Transmission system impacts at the PA and program-wide level
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 - 2006

[7] Public Utilities Code 216.6 was previously Public Utilities Code 218.5. The requirements have not changed.

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 sixth year impact evaluation of the SGIP through the end of 2006.
- **Section 2** is this introduction.
- **Section 3** presents a summary of the program status of the SGIP through the end of 2006.
- **Section 4** describes the sources of data used in this report for the different technologies.
- **Section 5** discusses the 2006 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; transmission and distribution impacts; efficiency and waste heat utilization requirements; and greenhouse gas emission reductions.
- **Appendix A** gives more detailed information on costs, annual energy produced, peak demand, and capacity factors by technology and fuel type.
- **Appendix B** discusses the transmission and distribution methodology, describes the data used, and presents more detailed results.
- **Appendix C** describes the methodology used for developing estimates of SGIP greenhouse gas emission impacts.
- **Appendix D** describes the data collection and processing methodology, including the uncertainty analysis of the program level impacts. The attachment to this appendix contains the performance distributions used in the uncertainty analysis.
- **Appendix E** gives an overview of the metering systems employed under the SGIP for metering electric generation, fuel consumption, and heat recovery.

3

Program Status

3.1 Introduction

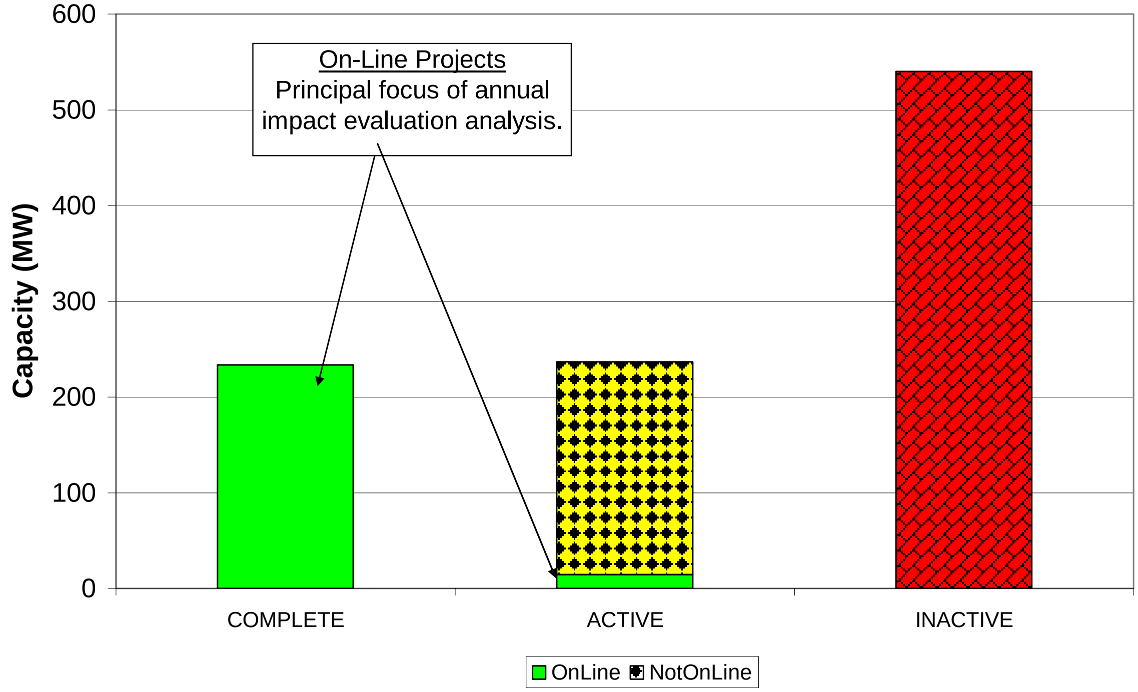
This section provides information on the status of the Self-Generation Incentive Program (SGIP) relative to all applications extending from Program Year 2001 (PY01) through the end of PY06 based on PA tracking data available through December 31, 2006. Information in this section includes the status of 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-PY06 SGIP Project Status as of 12/31/2006



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 2006, 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, projects that are withdrawn or rejected are 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. The number of projects is represented by an "n." The capacity (MW) refers to the total rebated capacity for those "n" projects.

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

Technology & Fuel	Complete		Active (All)		Total		
	(n)	(MW)	(n)	(MW)	(n)	(MW)	Avg Size (kW)
PV	638	81.1	605	154.2	1243	235.3	189
Wind	2	1.6	4	2.8	6	4.5	744
Fuel Cell - Nonrenewable	10	5.8	6	3.1	16	8.8	550
Fuel Cell - Renewable	2	0.8	10	8.0	12	8.7	725
Engine/Turbine - Nonrenewable	270	135.0	94	62.3	364	197.4	542
Engine/Turbine - Renewable	26	9.3	14	6.5	40	15.8	395
All	**948**	**233.6**	**733**	**236.9**	**1681**	**470.4**	**280**

There were nearly 1700 Complete and Active projects, representing over 470 MW of capacity in the SGIP by December 31, 2006. The principal focus of the 2006 impact evaluation is the subset of projects "on-line" by December 31, 2006. These projects, being connected to the grid and operational, are the ones that had an impact during PY06.

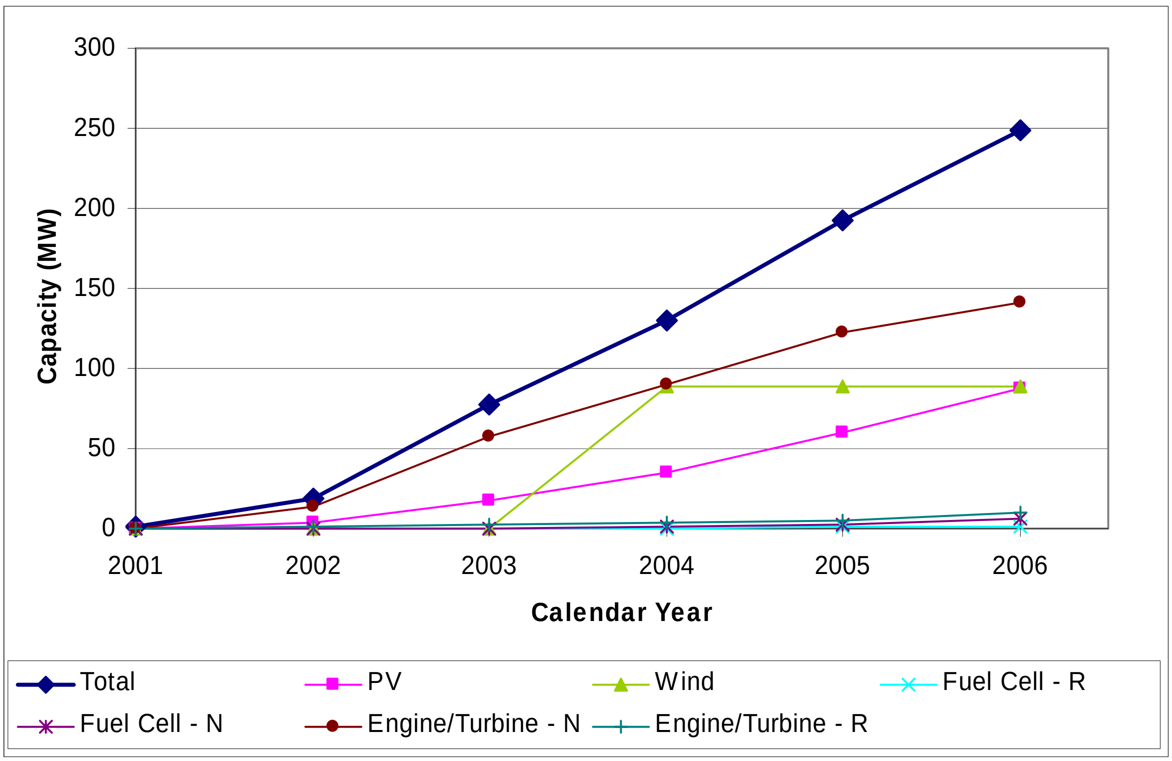
Table 3-2 provides information on the number and capacity of projects that are “on-line” even if they have not received incentive checks. The information is broken down by incentive level, technology type, and stage of implementation in the SGIP. By the end of 2006, “on-line” projects represented almost 1,000 projects and approximately 250 MW of rebated capacity.

Table 3-2: Quantity and Capacity of Projects On-Line as of 12/31/2006

Technology & Fuel	Complete		Active (On-Line)		Total On-Line Projects		
	(n)	(MW)	(n)	(MW)	(n)	(MW)	Avg Size (kW)
PV	637	81.0	34	6.7	671	87.7	131
Wind	2	1.6	0	0.0	2	1.6	824
Fuel Cell - Nonrenewable	10	5.8	1	1.0	11	6.8	614
Fuel Cell - Renewable	2	0.8	0	0.0	2	0.8	375
Engine/Turbine - Nonrenewable	270	135.0	12	5.7	282	140.8	499
Engine/Turbine - Renewable	26	9.3	2	1.3	28	10.6	377
All	**947**	**233.5**	**49**	**14.7**	**996**	**248.2**	**249**

Figure 3-2 shows the increase in rebated capacity of complete projects extending from 2001 through the end of 2006 by technology and fuel type. The capacity of all Complete projects more than tripled between the end of 2003 and the end of 2006 and the capacity of Complete[3] projects increased 23 percent (56 MW) from 2005 to 2006. PV systems installed between 2005 to 2006 contributed 28 MW of capacity, or approximately half of the growth of the SGIP during this period. Most of the remaining growth in capacity from 2005 to 2006 came from microturbines and IC engines. Wind and fuel cell systems had little, if any, growth during this same period.

Figure 3-2: Growth in On-Line Project Capacity from 2001-2006



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

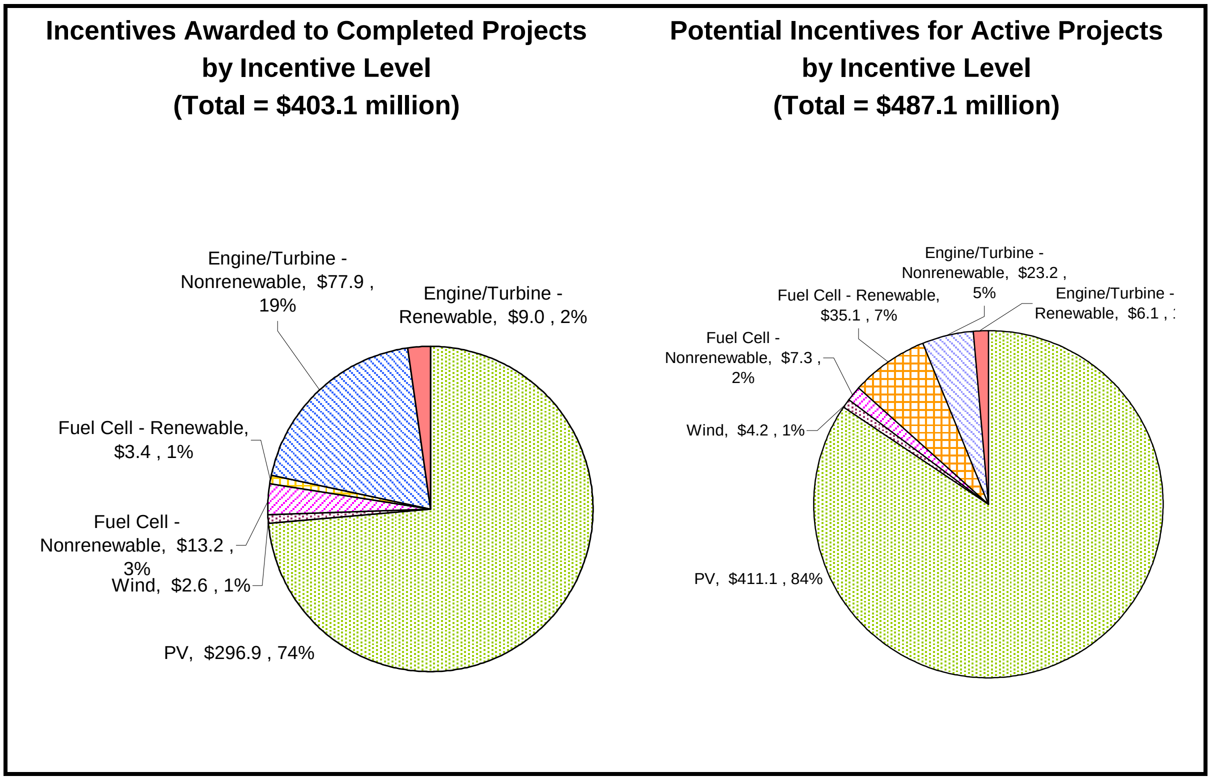
Table 3-3 shows the number of SGIP projects where the host site is an electric customer of an IOU or municipal utility. Generally, the largest project capacity overlap between IOU and municipal utilities occurs with PV systems. At the end of 2006, approximately 11 percent of the rebated PV capacity in the SGIP represented systems installed by sites that were also customers of municipal utilities. Approximately 2 percent of cogeneration (Engine/Turbine - Nonrenewable) capacity was dual-utility customers. Sixty-two of the 85 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 12/31/2006

Technology & Fuel	IOU		Municipal		Total On-Line	
	(n)	(MW)	(n)	(MW)	(n)	(MW)
Photovoltaics	586	77.7	85	10.0	671	87.7
Wind	1	1.0	1	0.7	2	1.6
Fuel Cell - Nonrenewable	10	5.8	1	1.0	11	6.8
Fuel Cell - Renewable	2	0.8	0	0.0	2	0.8
Engine/Turbine - Nonrenewable	269	136.7	13	4.0	282	140.8
Engine/Turbine - Renewable	28	10.6	0	0.0	28	10.6
All	**896**	**232.5**	**100**	**15.7**	**996**	**248.2**

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, 2006. By the end of PY06, over $403.1 million in incentive payments had been paid to Complete projects. The reserved backlog totals nearly $487.1 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 using nonrenewable fuel exceeded 1 MW, with average sizes of approximately 630 kW and 2.9 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, 2006 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 PY06 were medium-sized facilities with capacities of less than 1 MW.

Table 3-4: Installed Capacities of PY01-PY06 Projects Completed by 12/31/2006

Technology & Fuel	System Size (kW)				
	n	Mean	Minimum	Median	Maximum
Photovoltaic	638	127	28	62	1,050
Wind Turbine	2	824	699	824	950
Fuel Cell - Nonrenewable	10	575	200	500	1,000
Fuel Cell - Renewable	2	375	250	375	500
Internal Combustion Engine – Nonrenewable	174	630	60	500	4,110
Internal Combustion Engine – Renewable	10	626	160	602	991
Gas Turbine – Nonrenewable	4	2,905	1,210	2,942	4,527
Microturbine – Nonrenewable	92	150	28	106	928
Microturbine - Renewable	16	189	60	165	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. This was also the case at the end of 2005, and the mean system size of photovoltaic systems increased in 2006 from 115 to 127 kW, the mean size of gas turbines increased from 1297 kW to 2905 kW, and the mean size of microturbines increased from 147 kW to 156 kW.

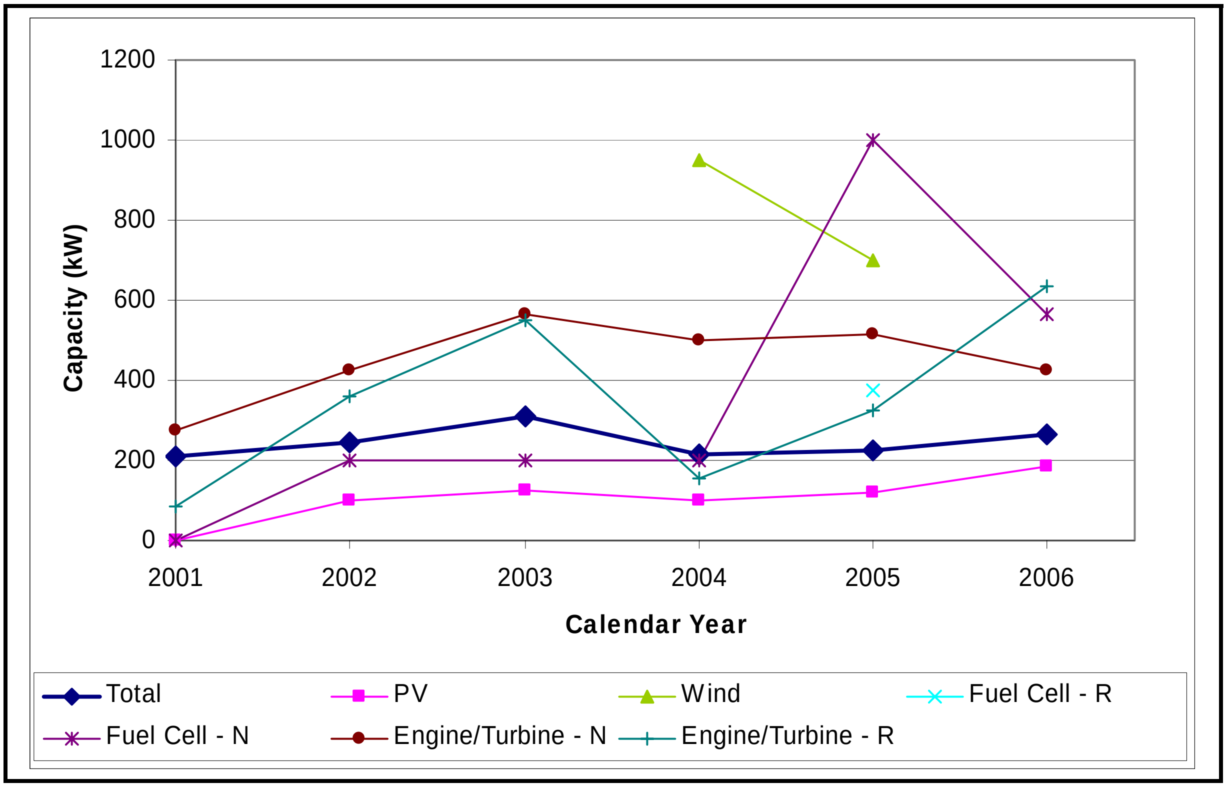
Table 3-5 summarizes the system capacity characteristics of Active projects by technology and incentive level. In general, the rated capacities of Active projects tend to be greater than their Complete project technology counterparts; therefore, the capacity of SGIP projects overall can be expected to increase again in 2007 as these larger, Active projects migrate to the Completed status.

Table 3-5: Rated Capacities of PY01-PY06 Projects Active as of 12/31/2006

Technology & Fuel	System Size (kW)				
	n	Mean	Minimum	Median	Maximum
Photovoltaic	605	255	30	132	2,495
Wind Turbine	4	704	250	783	1,000
Fuel Cell - Nonrenewable	6	508	250	400	1,000
Fuel Cell - Renewable	10	795	200	950	1,000
Internal Combustion Engine – Nonrenewable	62	682	75	425	3,992
Internal Combustion Engine – Renewable	8	714	36	765	1,516
Gas Turbine – Nonrenewable	4	2,754	1,000	2,744	4,527
Microturbine – Nonrenewable	28	322	56	170	2,253
Microturbine - Renewable	6	135	30	140	240

Figure 3-4 shows the trend of capacity for Complete projects from 2001 through the end of 2006. Largest increases in capacities in 2006 occurred with renewable-fueled engines/turbines, however, there were no new renewable-fueled fuel cell projects. There were also no new wind projects in 2006. Nonrenewable-fueled engines/turbines showed a decrease in capacity from 2003 to 2004, rose slightly from 2004 to 2005 but then decreased again in 2006. Average capacities of PV technologies ranged between 110 to 130 kW from 2002 through the end of 2005, but in 2006 increased to almost 200 kW. The net result has been that the average overall capacity of SGIP projects increased slightly from 2002 to 2003, but decreased back down in 2004 and 2005, but in 2006 the average capacity increased again to approximately 260 kW.

Figure 3-4: Trend of Capacity of Complete Projects from PY01-PY06



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 PY06. Average per-Watt eligible project costs represent capacity-weighted averages.

By the end of PY06, total eligible project costs (private investment plus the potential SGIP incentive) corresponding to Complete projects exceeded one billion dollars. PV projects account for the vast majority (63 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 35 percent of the total Complete project capacity installed through PY06. The combined costs of renewable and nonrenewable fueled engines and turbines account for the second highest total Complete project costs at $334 million (approximately 32 percent of the total eligible project costs), and correspond to 62 percent of the total Complete project installed capacity.

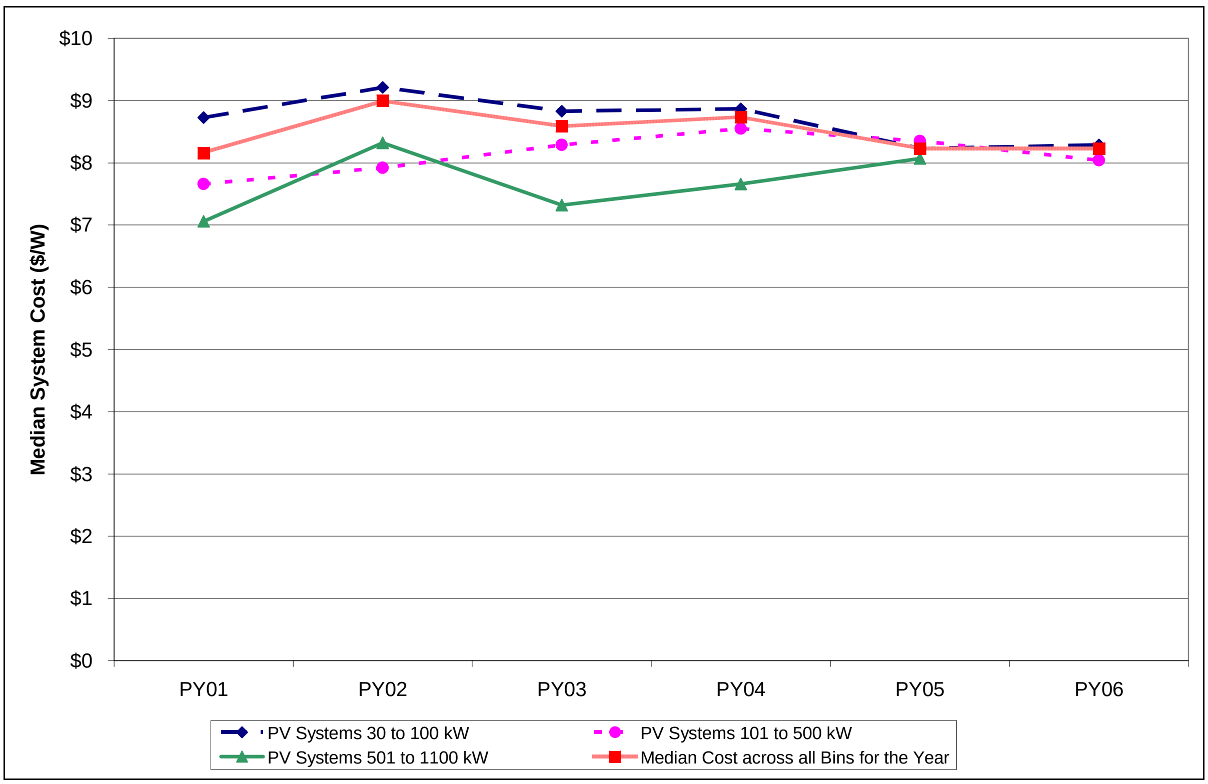
On an average cost-per-installed-Watt ($/Watt)-basis, fuel cell and PV projects are more costly than engine and microturbine projects. However, any comparison of these project costs must take into consideration the fundamentally different characteristics of the technologies. In the case of cogeneration 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–PY06 Projects

Technology & Fuel	Complete			Active		
	Total (MW)	Wt.Avg. ($/W)	Total ($ MM)	Total (MW)	Wt.Avg. ($/W)	Total ($ MM)
Photovoltaic	81.1	$8.19	$664	154.2	$8.51	$1,312
Wind Turbine	1.6	$3.26	$5	2.8	$2.87	$8
Fuel Cell - Nonrenewable	5.8	$7.22	$41	3.1	$6.56	$20
Fuel Cell - Renewable	0.8	$9.70	$7	8.0	$6.35	$50
Internal Combustion Engine – Nonrenewable	109.6	$2.22	$243	42.3	$3.81	$161
Internal Combustion Engine – Renewable	6.3	$2.65	$17	5.7	$3.72	$21
Gas Turbine – Nonrenewable	11.6	$1.87	$22	11.0	$2.42	$27
Microturbine – Nonrenewable	13.8	$3.06	$42	9.0	$3.24	$29
Microturbine - Renewable	3.0	$3.23	$10	0.8	$4.09	$3
Total	**233.6**	**$4.50**	**$1,052**	**236.9**	**$6.89**	**$1,633**

Cost trends for Complete PV projects between PY01 through PY06 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 PY06. Second, the smallest-sized PV systems (i.e., those between 30 to 100 kW) had the least change in cost over the first 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 $8.07 per Watt). Fourth, the medium-sized systems (i.e., those between 101 to 500 kW) had the lowest installed costs at the end of 2006 (at $8.04 per Watt). As of December 31, 2006, there were not yet any completed large PV projects that applied in 2006.

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, then the medium-sized engines median cost decreased by almost $0.60 per Watt in 2005. 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. It appears that costs decreased in 2005, but the median of each group is only based on a few (no more than 4) systems. It is expected that the PY07 median system cost will increase relative to the previous years due to the addition of NO_x control technologies that may be required to meet the NO_x standard of 0.07 lbs/MW-hr for distributed generation.

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

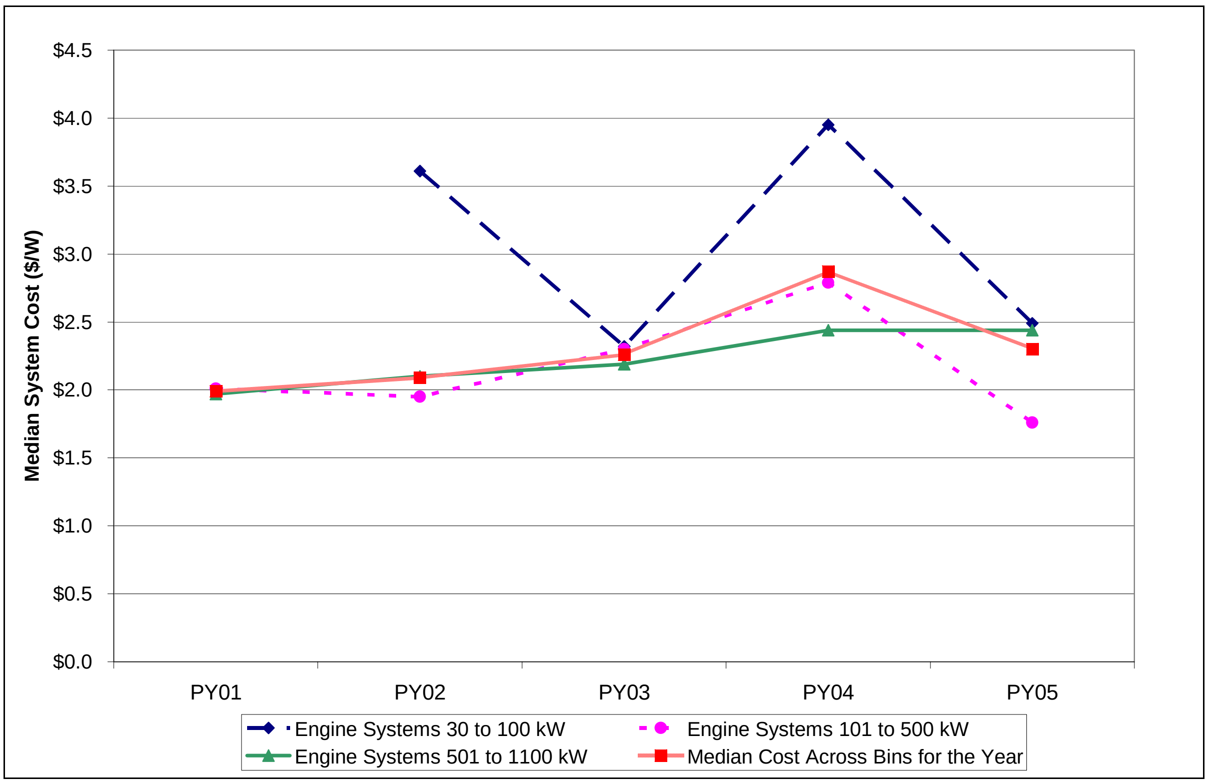
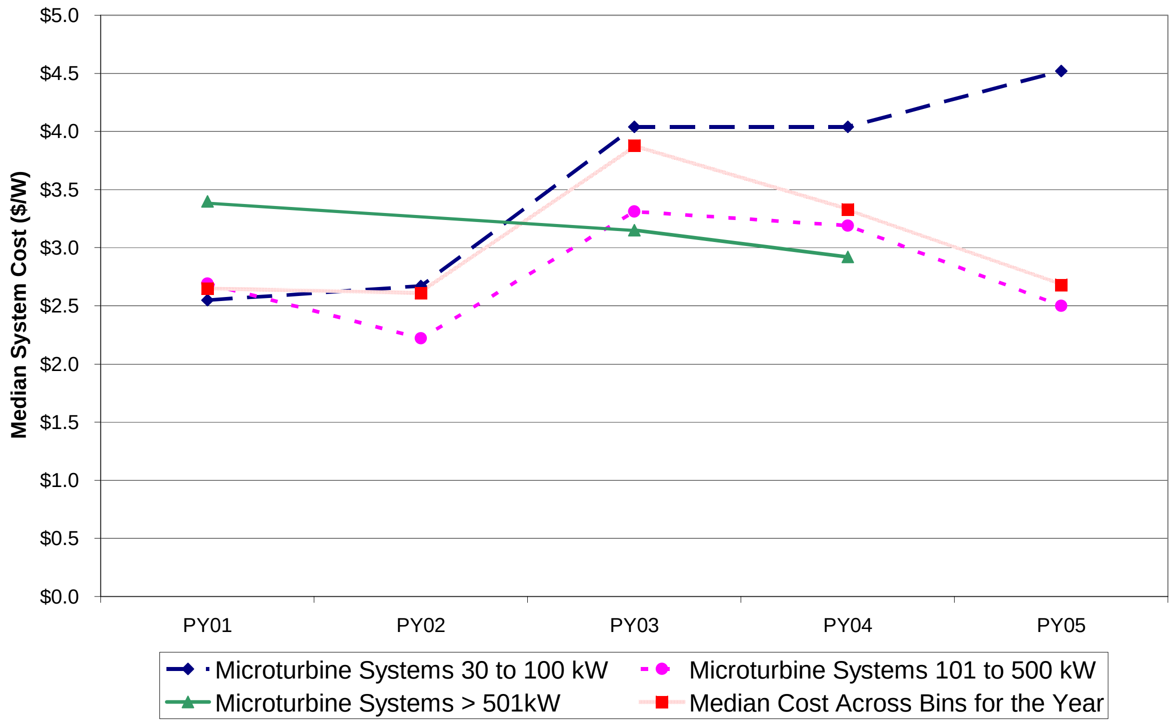


Figure 3-7 is a cost trend for natural gas-fired microturbines in the Complete project category. Generally, small to medium-sized microturbines demonstrated moderate increases in median costs from PY02 through PY04, with the costs of the 30 to 100 kW range rising more rapidly than the medium-sized microturbines.

The median of costs of systems less than 501 kW increased substantially during PY03. In 2005, the price of medium sized systems (101 to 500 kW) decreased back to the 2002 level, while the price of small systems (30 to 100 kW) increased again. However, the 2005 median price of the all size groups is based on no more than three projects each.

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 83 percent of the incentives reserved for Active projects.

Table 3-7: Incentives Paid and Reserved

	Complete Incentives Paid			Active Incentives Reserved		
Technology & Fuel	**Total (MW)**	**Avg. ($/W)**	**Total ($ MM)**	**Total (MW)**	**Avg. ($/W)**	**Total ($ MM)**
Photovoltaic	81.1	3.7	296.9	154.2	2.7	411.1
Wind Turbine	1.6	1.6	2.6	2.8	1.5	4.2
Fuel Cell - Nonrenewable	5.8	2.3	13.2	3.1	2.4	7.3
Fuel Cell - Renewable	0.8	4.5	3.4	8.0	4.4	35.1
Internal Combustion Engine – Nonrenewable	109.6	0.6	63.6	42.3	0.5	20.8
Internal Combustion Engine – Renewable	6.3	0.9	5.7	5.7	0.9	5.1
Gas Turbine – Nonrenewable	11.6	0.2	2.9	11.0	0.2	2.4
Microturbine – Nonrenewable	13.8	0.8	11.5	9.0	0.6	5.1
Microturbine - Renewable	3.0	1.1	3.4	0.8	1.3	1.1
Total	**233.6**	**$1.73**	**$403.1**	**236.9**	**$2.08**	**$492.1**

[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, renewable- and nonrenewable-fueled fuel cells have the highest cost, followed by PV. The higher first cost of 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 the renewable-fueled fuel cells 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 nonrenewable-fueled microturbines and renewable-fueled microturbines, respectively.

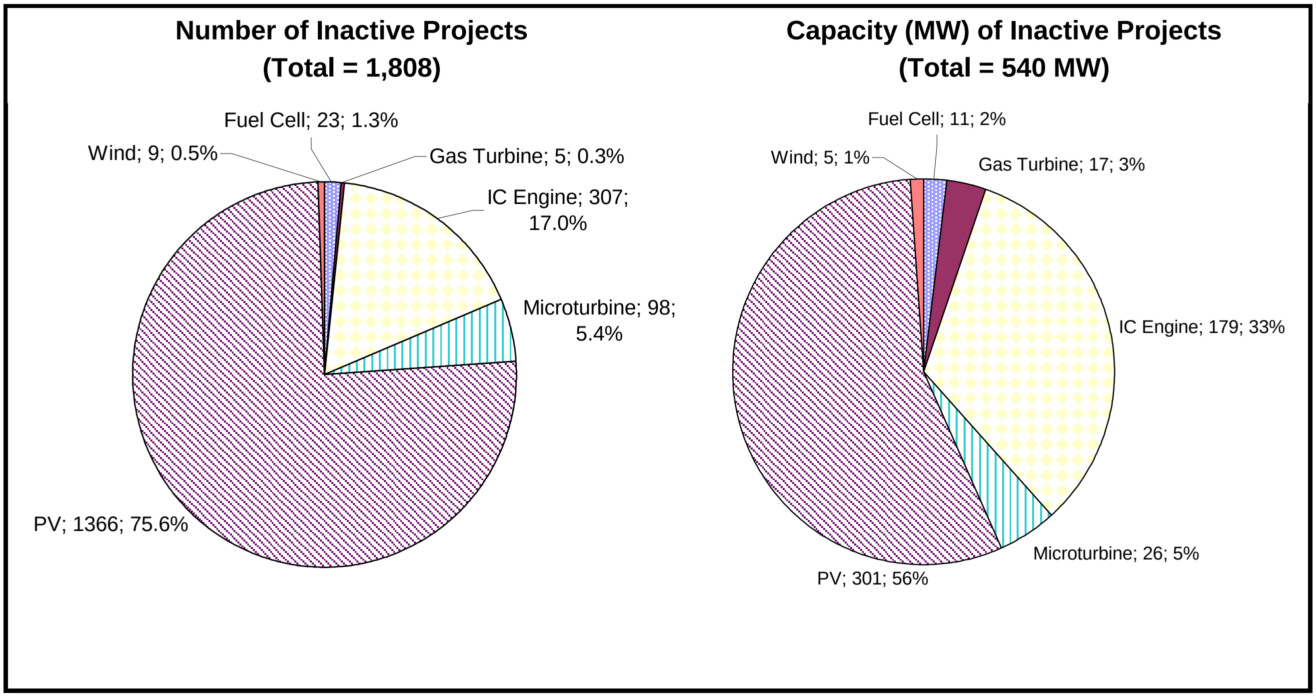
Table 3-8: SGIP Participants' Out-of-Pocket Costs after Incentive

	Complete			Active		
Technology & Fuel	**Total (MW)**	**Avg. ($/W)**	**Total ($ MM)**	**Total (MW)**	**Avg. ($/W)**	**Total ($ MM)**
Photovoltaic	81.1	$4.05	$328	154.2	$5.83	$898
Wind Turbine	1.6	$1.63	$3	2.8	$1.37	$4
Fuel Cell - Nonrenewable	5.8	$4.49	$26	3.1	$3.99	$12
Fuel Cell - Renewable	0.8	$5.20	$4	8.0	$1.87	$15
Internal Combustion Engine – Nonrenewable	11.6	$1.62	$19	11.0	$2.20	$24
Internal Combustion Engine – Renewable	109.6	$1.63	$179	42.3	$3.32	$140
Gas Turbine – Nonrenewable	6.3	$1.67	$10	5.7	$2.84	$16
Microturbine – Nonrenewable	13.8	$2.20	$30	9.0	$2.62	$24
Microturbine - Renewable	3.0	$2.05	$6	0.8	$2.79	$2
Total	**233.6**	**$2.78**	**$649**	**236.9**	**$4.81**	**$1,141**

3.4 Characteristics of Inactive Projects

As of December 31, 2006, there were 1,808 Inactive projects (those either withdrawn or rejected), representing 540 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:

- PV projects constitute the largest share of number of Inactive projects (1,366 or 75.6 percent) and the largest share of total Inactive capacity (301 MW or 56 percent).
- IC Engines (fueled by either nonrenewable or renewable fuel) account for the second largest share of number of Inactive projects (307 or 17 percent) and the second largest share of total Inactive capacity (179 MW or 33 percent).
- The 98 Inactive Microturbine (fueled by either nonrenewable or renewable fuel) projects account for 26 MW of total Inactive capacity (5 percent).
- Five Inactive Gas Turbine projects account for 17 MW of total Inactive capacity (3 percent).
- Nine Inactive Wind projects account for 5 MW of total Inactive capacity (1 percent) and 23 Inactive Fuel Cell (fueled by either nonrenewable or renewable fuel) projects represent 11 MW of total Inactive capacity (2 percent).

4

Sources of Data for the Impact Evaluation

Data collection activities supporting the sixth-year impact 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.

4.1 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, necessary facility information is collected 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 available operations data, as required. Information collected for Program M&E purposes augmented that developed by the Program

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[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.

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 sixth-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. This was encountered with some cogeneration systems installed in schools, as well as with some renewable-fueled engine/turbine projects 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 early 2006.

As the data collection effort grew it became clear that the team could no longer rely on data from third-party or host customer metering. In numerous instances agreements and plans concerning these data did not translate into validated data records available for analysis. Uninterrupted collection and validation of reliable metered performance data 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 had led to this initial strategy.

In mid-2006 the evaluation contractor responded to these issues from several fronts. Costs were escalating rapidly. The time spent collecting data from Hosts, Applicants, and third parties was increasing. System owners were increasingly reluctant to shut down their cogeneration systems for installation of invasive metering equipment, requiring expensive hot tapping. Communication efforts were failing at an unacceptable rate. As a result of these issues, the evaluation contractor moved to noninvasive metering equipment such as ultrasonic flow meters, clamp-on temperature sensors, and wireless, cellular-based communications. The increase in equipment costs was offset by a decrease in installation time and a potential decrease in maintenance problems. Appendix E provides detailed information on the new metering equipment.

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 renewable-fueled fuel cell and engine/turbine projects. Prior to 2005 all such on-line projects had utilized only 100% renewable fuel. During 2005 and 2006 four 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.

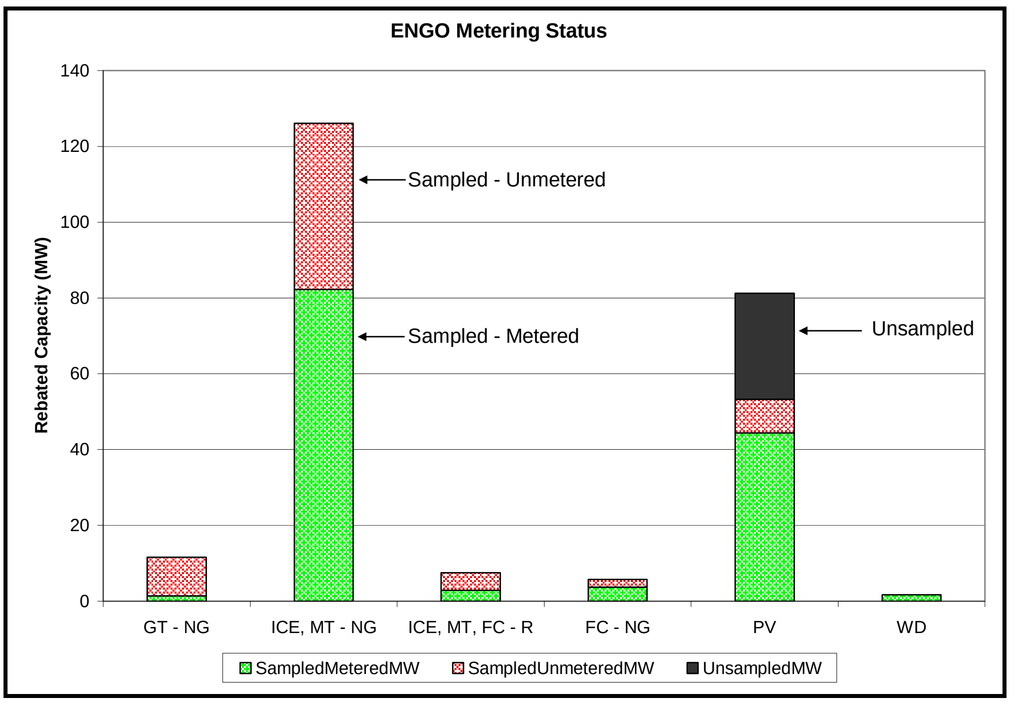
The natural gas usage data used in the sixth-year impacts evaluation were obtained from natural gas utilities, SGIP participants, and natural gas metering installed by the program evaluation contractor. The data were reviewed and their bases were documented prior to processing into a data warehouse. 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.

4.2 Metered Performance Data Collection Status Summary

As of the end of 2006, 996 PY01-PY06 SGIP projects were determined to be on-line. These projects correspond to 248 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 2006. Data collection status by PA is discussed in Appendix D.

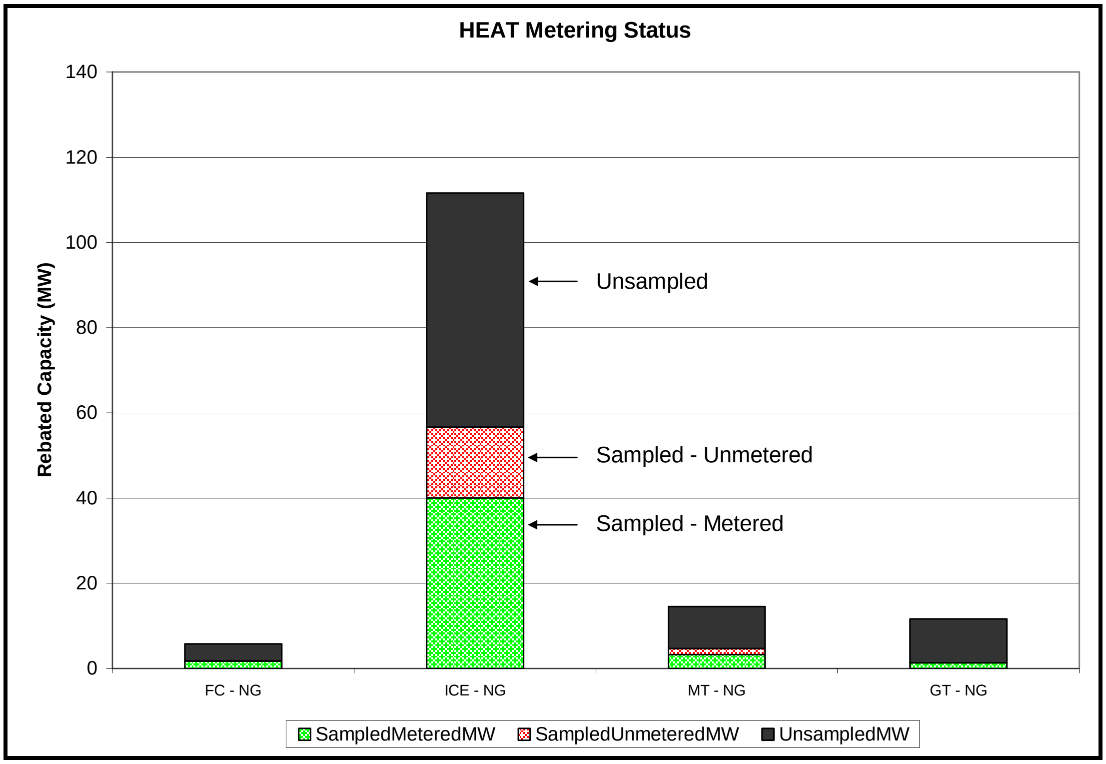
The status of ENGO data collection is summarized in Figure 4-1. A substantial quantity of ENGO metering installation activity remains to be completed. This activity is ongoing and is being carried out by the Program Administrators and the SGIP evaluation contractor. To date PV is the only technology for which some on-line capacity is unsampled. This group of projects includes PY03-PY06 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 2006 that called for electric metering for all nonrenewable-fueled engine/turbine 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 2007 is installation of additional ENGO metering for nonrenewable-fueled gas turbines and renewable-fueled engines/turbines.

Figure 4-1: ENGO Data Collection as of 12/31/2006



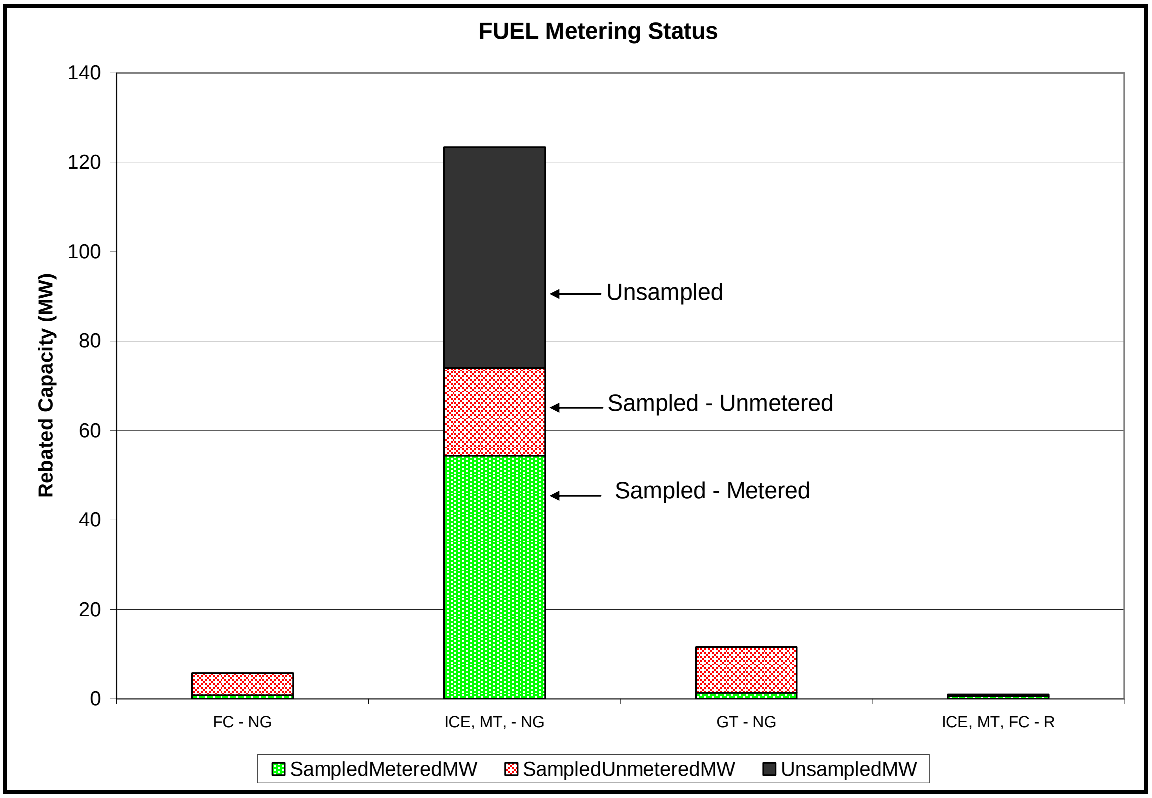
The status of HEAT data collection is summarized in Figure 4-2. Overall, more HEAT metering is needed for all technologies; however, the most important area for improvement for 2007 is nonrenewable-fueled Gas Turbines. These systems are relatively larger capacity and it is more likely that HEAT metering will be available from the Applicant. The evaluation contractor will install HEAT metering in situations where data are unavailable or of insufficient quality for the purposes of impacts evaluations.

Figure 4-2: HEAT Data Collection as of 12/31/2006



The status of FUEL data collection is summarized in Figure 4-3. 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 4-3: FUEL Data Collection as of 12/31/2006



5

Program Impacts

This section presents impacts from SGIP projects that were on-line through the end of PY06. Impacts examined include affects on energy delivery; peak demand; waste heat utilization and efficiency requirements; and greenhouse gas emission reductions.[1] Impacts of SGIP technologies are examined at a program-wide level and at PA-specific levels.

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, 2006. 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. A description of the methods used for estimating performance of non-metered facilities is contained in Appendix D. Data availability and corresponding analytic methodologies vary by program level and technology.

This section is composed of the following five subsections:

5.1. Energy and Non-coincident Demand Impacts
5.2. Peak Demand Impacts
5.3. Transmission and Distribution Impacts
5.4. Efficiency and Waste Heat Utilization
5.5. Greenhouse Gas Emission Reductions

[1] Renewable fuel use compliance had been discussed in the 2005 Impacts Evaluation Report. Per direction from the Working Group, this topic has been dropped from the impacts evaluation report and will instead be discussed in the Renewable Fuel Use Reports.

5.1 Energy and Non-Coincident Demand Impacts

Overall Program Impacts

Electrical energy and demand impacts were calculated for Complete and Active projects that began normal operations prior to December 31, 2006. Impacts were estimated using available metered data for 2006, system characteristics information from program tracking systems maintained by the PAs, and augmented with information obtained over time by Itron.

By the end of 2006, 996 SGIP facilities were on-line representing over 248 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 2006. Energy delivery is described by technology and fuel.

Table 5-1: Statewide Energy Impact in 2006 by Quarter (MWh)

Technology	Fuel	Q1-2006 (MWh)	Q2-2006 (MWh)	Q3-2006 (MWh)	Q4-2006 (MWh)	Total (MWh)
FC	**N**	4,573	4,874	6,932	9,792	26,170
FC	**R**	646	614	520	718	2,498
GT	**N**	13,686	12,189	13,009	16,403	55,287
ICE	**N**	85,833	91,147	92,170	84,286	353,436
ICE	**R**	1,484	2,547	3,161	3,218	10,409
MT	**N**	10,463	12,027	12,193	12,508	47,191
MT	**R**	1,697	2,331	2,032	3,221	9,281
PV		17,586	31,507	35,199	19,718	104,010
WD		521	651	707	394	2,274
	TOTAL	**136,489**	**157,886**	**165,923**	**150,259**	**610,557**

Overall, natural gas fueled technologies provided nearly 80 percent of the electricity generated by SGIP systems during 2006. Natural gas fueled ICE, a technology composing almost half of the total program generating capacity, contributed the single largest share (58 percent) of the total annual delivered energy. PV, comprising just under 40 percent of total program capacity, followed in a distant second, providing 17 percent of the total annual delivered energy.

Capacity factor represents the fraction of rebated capacity that is actually generating over a specific time period. Consequently, capacity factor is useful in providing insight into the capability of a generating technology to provide power during a particular time period. For example, annual capacity factors indicate the fraction of rebated capacity that could, on average be expected from that technology over the course of a year. Annual weighted average capacity factors for SGIP technologies were developed by comparing annual generation against rebated capacity. Table 5-2 lists these annual capacity factors by technology. Appendix A provides further discussion of annual capacity factors by both technology and basis.

Table 5-2: Annual Capacity Factors by Technology

Technology	Annual Capacity Factor* (kWyear/kWyear)
FC	0.700 †
GT	0.843 [a]
ICE	0.359 †
MT	0.404 [a]
PV	0.162
WD	0.157 †

* [a] indicates confidence is less than 70/30. † indicates confidence is better than 70/30. No symbol indicates confidence is better than 90/10.

Some of the technologies listed in Table 5-2 are fueled by natural gas or renewable fuels (e.g., biogas). In those instances, the capacity factors represent an average over both fuel types. Table 5-3 provides a fuel specific weighted average annual capacity factors for those technologies that might use natural gas or renewable methane gas.

Table 5-3: Annual Capacity Factors by Technology and Fuel

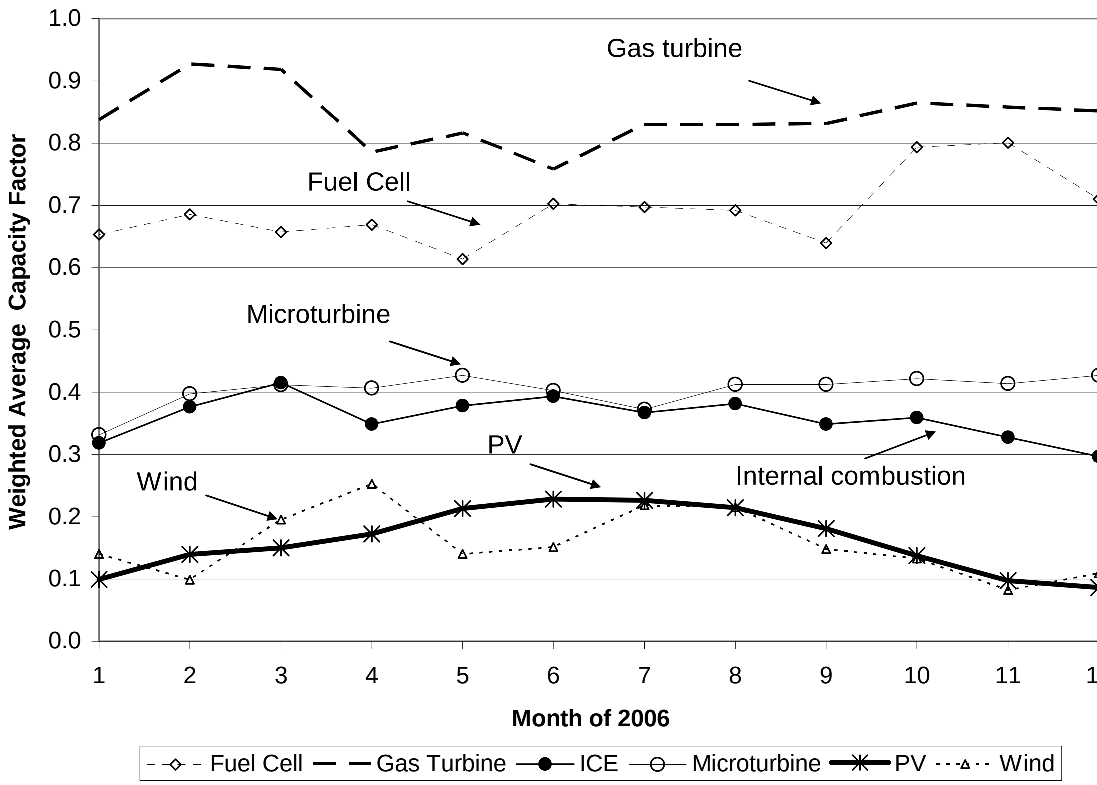
	Annual Capacity Factor* (kWyear/kWyear)	
Technology	**Natural Gas**	**Renewable Fuel**
FC	0.762 †	0.380 †
GT	0.843 †	
ICE	0.366	0.218
MT	0.414	0.358 †

* [a] indicates confidence is less than 70/30. † indicates confidence is better than 70/30. No symbol indicates confidence is better than 90/10.

Not unexpectedly, natural gas fueled gas turbines and fuel cells showed the highest average annual capacity factors; staying at or above 0.7. Both of these technologies are known to be efficient and tend to operate as base load capacity, which drives up their average capacity factor. Conversely, technologies with intermittent energy resources, such as wind and PV, tend to show lower average annual capacity factors. Similarly, the emerging status of using biogas resources in fuel cells is reflected in its significantly lower capacity factor, when compared to its natural gas fueled counterpart.

The average annual capacity factor provides a single point in time view of the generating capability of a technology. A more useful view is provided by examining how the capacity factor varies throughout the year. Figure 5-1 shows monthly weighted average capacity factors for SGIP technologies through 2006. As expected, natural gas turbines in the program maintained the highest monthly capacity factors throughout the year, seldom falling below 0.8. Fuel cells maintained monthly capacity factors above 0.6. However, the monthly capacity factors shown in Figure 5-1 for fuel cells represents a mix of fuel cells; some powered by natural gas and some powered by biogas. Fuel cells are extremely sensitive to fuel quality. As a result of the lower fuel quality of biogas, biogas powered fuel cells encounter additional operational issues that reduce their capacity factors. Monthly capacity factors for natural gas powered fuel cells would be significantly higher than the combined natural gas/biogas capacity factors shown here for fuel cells. Appendix A provides similar capacity factor charts but that distinguish technologies by fuel type. Another interesting observation from Figure 5-1 is that both IC engines and microturbines have monthly capacity factors that tend to run consistently between 0.3 and 0.4 throughout the year.

Figure 5-1: Weighted Average Capacity Factor by Technology and Month (2006)



PA-specific Program Impacts

Aggregating projects by PA, Table 5-4 provides annual energy impacts for SGIP technologies deployed within each PA service territory. Again, energy delivery is described by system type. Appendix A provides similar tables of annual energy impacts that distinguish technologies by fuel type.

Table 5-4: Energy Impacts in 2006 by PA (MWh)

Technology	PG&E (MWh)	SCE (MWh)	SCG (MWh)	SDREO (MWh)	Total (MWh)
FC	14,893	2,991	1,921	8,863	28,668
GT	17,944	0	34,692	2,650	55,287
ICE	161,048	44,067	130,897	27,833	363,845
MT	18,798	17,175	17,211	3,289	56,473
PV	56,509	20,372	13,093	14,036	104,010
WD	0	2,274	0	0	2,274
Total	**269,193**	**86,879**	**197,815**	**56,671**	**610,557**

SGIP systems operating in PG&E's service territory accounted for over 40 percent of the total electricity delivered by the program during 2006; with nearly 60 percent of PG&E's contribution stemming from IC engines. A similar association is seen with SGIP systems in Southern California Gas (SCG) service territory, which delivered over 30 percent of the total electricity delivered by the program; with over 65 percent of that derived from IC engines. However, because SCG does not provide electricity services, PV system contribution to annual electricity delivery is less than 10 percent. In all the other PA areas, PV contributes at least 20 percent of the annual electricity delivery.

Table 5-5 presents annual weighted average capacity factors for each technology and PA for the year 2006. Where entries are blank the PA had no on-line systems of that technology. Additional tables in Appendix A differentiate annual capacity factors by fuel type.

Table 5-5: Annual Capacity Factors by Technology and PA

Technology	PG&E	SCE	SCG	SDREO
	Annual Capacity Factor* (kWyear/kWyear)			
FC	0.687 †	0.420 †	0.894	0.889
GT	0.790 [a]	0.000	0.880	0.762
ICE	0.396 [a]	0.236 †	0.386 [a]	0.344
MT	0.387 [a]	0.455 †	0.439 †	0.231
PV	0.167	0.141	0.165	0.175
WD		0.157 [a]		

*For rows with basis of Total only: * [a] indicates confidence is less than 70/30. † indicates confidence is better than 70/30. No symbol indicates confidence is better than 90/10.

Capacity factors in Table 5-5 mimic the program-wide capacity factors shown earlier with the exception of the fuel cell capacity factor for SCE. The 0.42 capacity factor for fuel cells in SCE reflects the influence of biogas fuel. As noted earlier, additional operational issues are encountered when using biogas in fuel cells, which can significantly impact rating and overall availability. During 2006, SCE was the only IOU that had biogas powered fuel cells. This substantially lowered the overall fuel cell capacity factor for SCE.

5.2 Peak Demand Impacts

Overall Peak Demand Impacts

The ability of SGIP projects to supply electricity during times of peak demand represents a critical impact. Table 5-6 summarizes the overall SGIP program impact on electricity demand coincident with the 2006 CAISO system peak load. The table shows the number of facilities on line at the time of the peak; the operating capacity at peak; the demand impacts; and the hourly capacity factor. In 2006, the CAISO system peak reached a maximum value of 50,198 MW on July 24 during the hour from 3:00 to 4:00 p.m. (PDT). This was substantially above the peak load of 45,380 MW that occurred at the same hour of day on July 20 of 2005. There were 905 SGIP projects known to be on-line when the CAISO experienced the 2006 summer peak, but generator electric interval-metered data were available for only 568 of them. While the total capacity of these on-line projects exceeded 221 MW, the total impact of the SGIP projects coincident with the CAISO peak load is estimated at slightly above 103 MW. Tables in Appendix A differentiate peak demand impacts by natural gas versus renewable methane fuel.

Table 5-6: Demand Impact Coincident with 2006 CAISO System Peak Load

Technology	On-Line Systems (n)	Operational (kW)	Impact (kW)	Hourly Capacity Factor* (kWh/kWh)
FC	8	4,800	3,372	0.703 [a]
GT	3	7,093	5,789	0.816 †
ICE	185	116,184	49,942	0.430 [a]
MT	98	16,182	5,465	0.338 [a]
PV	609	75,808	38,744	0.511 [a]
WD	2	1,649	53	0.032
TOTAL	**905**	**221,715**	**103,365**	

* [a] indicates confidence is less than 70/30. † indicates confidence is better than 70/30. No symbol indicates confidence is better than 90/10.

Average annual and average monthly capacity factors are indicators of the capability of a technology to provide power over the course of a year or seasonally within a year. The hourly capacity factor at peak measures the capability of a technology to provide power when electricity demand is highest and the additional generation is most needed in the electricity system. For the summer peak in 2006, gas turbines and fuel cells operating in the SGIP demonstrated very high peak capacity factors; both above 70 percent. Microturbines and IC engines had average peak capacity factors well below 70 percent; typically falling below 45 percent. Under the 2006 summer peak conditions, PV systems demonstrated an average peak capacity factor exceeding 50 percent. The average peak capacity factor for wind was very low; falling below 5 percent. However, as there were only two wind systems operating in the

SGIP during 2006, this hourly peak capacity factor should not be considered representative of wind performance in general.[2]

Timing of peak demand is an important factor in the hourly peak capacity factor for intermittent technologies, such as wind or solar. Figure 5-2 profiles the hourly weighted average capacity factor for each technology from morning to early evening during the 2006 peak day. The plot also indicates the hour and value of the CAISO peak load. The influence of timing of peak demand is readily apparent with PV. If the CAISO peak hour had occurred at 1-2 pm on July 24th, the hourly peak capacity factor for PV would have exceeded 60 percent. Appendix A provides similar charts that differentiate by natural gas versus renewable methane fuel.

Figure 5-2: CAISO Peak Day Capacity Factors by Technology

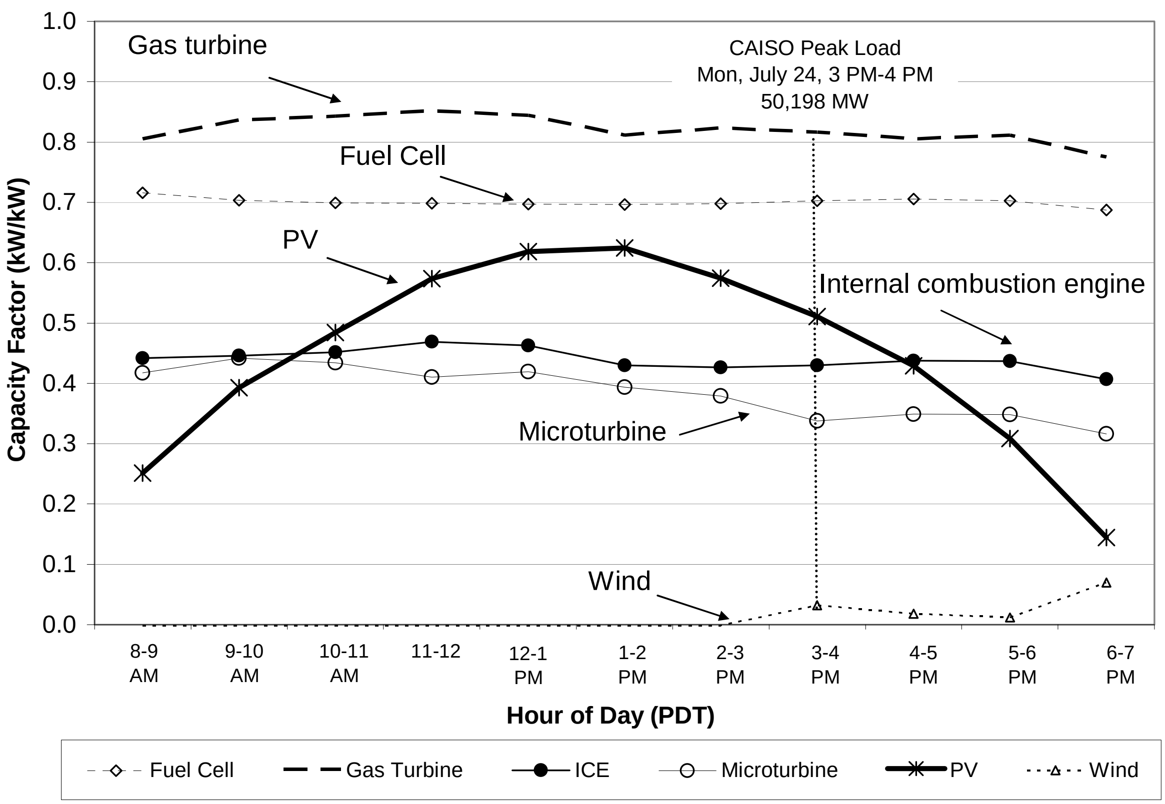
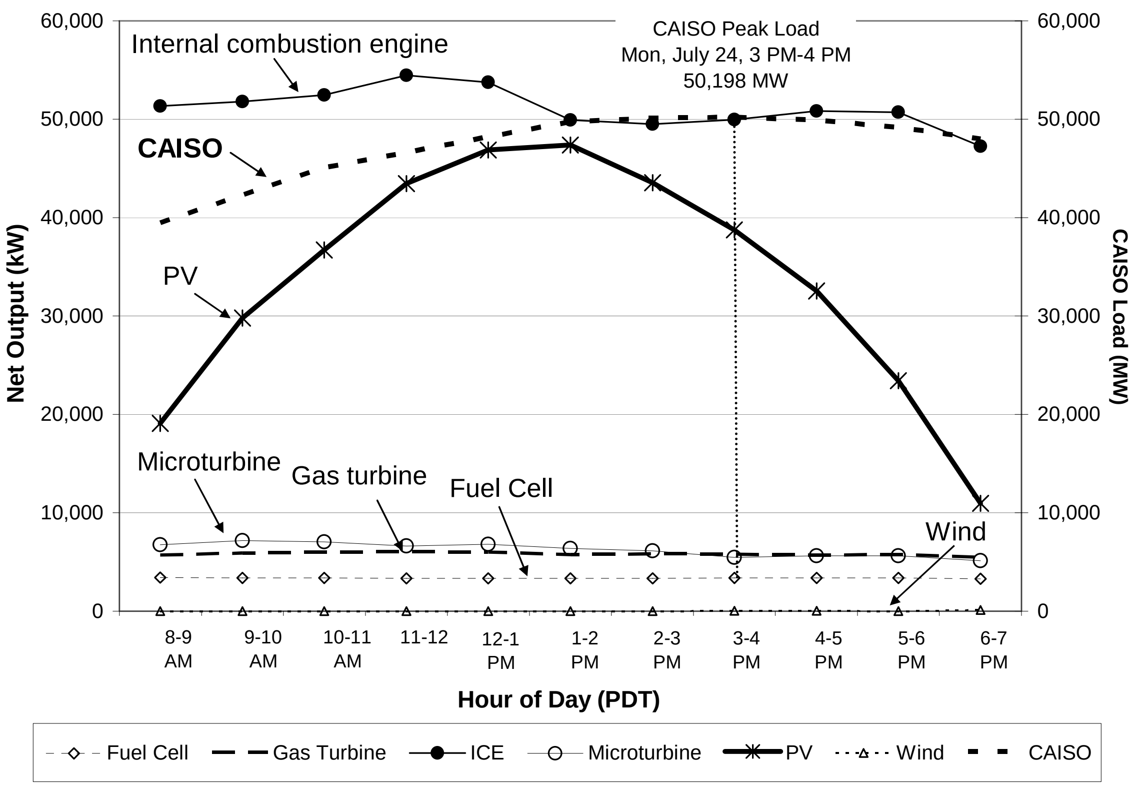


Figure 5-3 plots the hourly total net electrical contribution for each SGIP technology from morning to early evening during the 2006 peak day. This figure is useful in assessing the potential impact of increasing amounts of a particular SGIP technology on meeting peak hour energy delivery. For example, SGIP's 609 PV systems provided approximately 40,000 kW

2 The California Energy Commission has collected and reported wind capacity factors for wind energy systems operating in the state over a number of years. Average annual wind capacity factors range from 14 to 26 percent. Peak hour capacity factors range from 30 to as high as 60 percent at 6 pm (California Energy Commission, "Wind Power Generation Trends at Multiple California Sites," CEC-500-2005-185, December 2005)

of power to the grid during the peak hour. These 609 PV systems represented approximately 76 MW of operational PV capacity. In comparison to the CAISO peak hourly demand for 2006 of nearly 40,000 MW, SGIP's PV contribution is 0.1 percent of the total. However, if these results are translated to 3000 MW (i.e., the amount targeted in the California Solar Initiative) of solar PV, this means PV could have potentially contributed over 1,500 MW-hr of electricity during the peak hour; or nearly 4 percent of the required peak demand. However, because PV's contribution occurs primarily at the distribution system level, this 4 percent could prove to be a very valuable contribution to the grid. In addition, California's electricity mix relies on approximately 3000 MW of older, more polluting and costly peaking units to help meet peak summer demand.[3] Consequently, 3000 MW would represent sufficient peaking capability to displace nearly half the capacity of the peaking units. Moreover, it should be noted that the performance results shown in Figure 5-3 represent PV systems with predominately a southern exposure. PV systems with a southwestern orientation would have a significantly higher contribution to peak.[4]

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



3 California Energy Commission, "2007 Data based of California Power Plants," from http://www.energy.ca.gov/database/index.html#powerplants

4 A southwestern orientation could increase peak hour electricity delivery by as much as 30 percent, depending on location. See "PV Solar Costs and Incentive Factors," Itron report to the CPUC Self-Generation Incentive Program, February 2007

PA-Specific Peak Demand Impacts

Table 5-7 through Table 5-9 present the total net electrical output during the respective peak hours of the three large, investor-owned electric utilities. The top portions of each table list the date, hour, and load of the utility's peak hour day. The tables also show the number of SGIP type facilities on line at the time of the peak; the operating capacity at peak; and the demand impact. Tables in Appendix A differentiate electric utility peak demand impacts by natural gas versus renewable methane fuel.

Results presented for the peak days of the three individual electric utility do not strictly include all systems or only systems administered by the PA associated with the electric utility. About half of systems administered by SCG feed SCE's distribution grid, while a small number feed PG&E or SDG&E and the remainder feed small electric utilities. A small number of PG&E's systems feed directly into distribution grids for small electric utilities.

Table 5-7: Electric Utility Peak Hours Demand Impacts – PG&E

Elec PA	Peak (MW)	Date	Hour (PDT)
PG&E	**22,544**	**25-Jul-06**	**6 PM**

Technology	On-Line Systems (n)	Operational (kW)	Impact (kW)	Hourly Capacity Factor (kWh/kWh)
FC	6	3,250	2,295	0.706
GT	2	2,593	1,930	0.744
ICE	78	48,267	21,534	0.446
MT	33	5,868	2,431	0.414
PV	276	38,039	7,759	0.204
WD	0	0	0	
TOTAL	**395**	**98,017**	**35,949**	**0.367**

PG&E's peak demand occurred at 6 pm on July 25th. Gas turbines and fuel cells that were operating under the SGIP at that time reflected high hourly capacity factors; both exceeding 70 percent. IC engines and microturbines operating under the SGIP showed capacity factors in the 40 to 45 percent range. PV systems, due to the limited amount of insolation available at 6 pm had an average peak capacity factor of 20 percent. The combined SGIP contribution to peak generation provided an overall SGIP peak capacity factor of 37 percent. Note also that the electricity contribution from the combined SGIP facilities operating in PG&E's service territory during the 2006 summer peak provided 0.4 percent of the required demand.

Table 5-8: Electric Utility Peak Hours Demand Impacts – SCE

Elec PA	Peak (MW)	Date	Hour (PDT)
SCE	23,148	25-Jul-06	4 PM

Technology	On-Line Systems (n)	Operational (kW)	Impact (kW)	Hourly Capacity Factor (kWh/kWh)
FC	2	750	171	0.228
GT	1	4,500	3,920	0.871
ICE	82	54,176	26,553	0.490
MT	45	7,722	3,748	0.485
PV	177	19,179	6,372	0.332
WD	2	1,649	310	0.188
TOTAL	**309**	**87,976**	**41,074**	**0.467**

SCE's peak demand occurred at 2 pm, slightly earlier than PG&E's peak. Like PG&E, the gas turbine operating under the SGIP showed a very high peak capacity factor. Unlike PG&E, the SGIP fuel cells operating in SCE's service territory demonstrated a low peak capacity factor. As explained earlier, one of the fuel cells is powered with biogas, which resulted in an overall lower capacity factor. IC engines and microturbines operating under the SGIP showed very similar peak capacity factor for SCE as for PG&E. This observation is significant in that it strongly suggests that the majority of the IC engine and microturbine capacity operating under the SGIP in both PG&E and SCE do not load follow.[5] The SGIP PV facilities had a better peak capacity in SCE than in PG&E for 2006; primarily due to the peak demand occurring earlier in the afternoon. Lastly, wind peak capacity factor for SCE was close to 20 percent, but should be recognized as representing only two wind systems.

5 Another possibility is that ratings of IC engines and microturbines are significantly lower than their rebated capacities.

Table 5-9: Electric Utility Peak Hours Demand Impacts – SDG&E

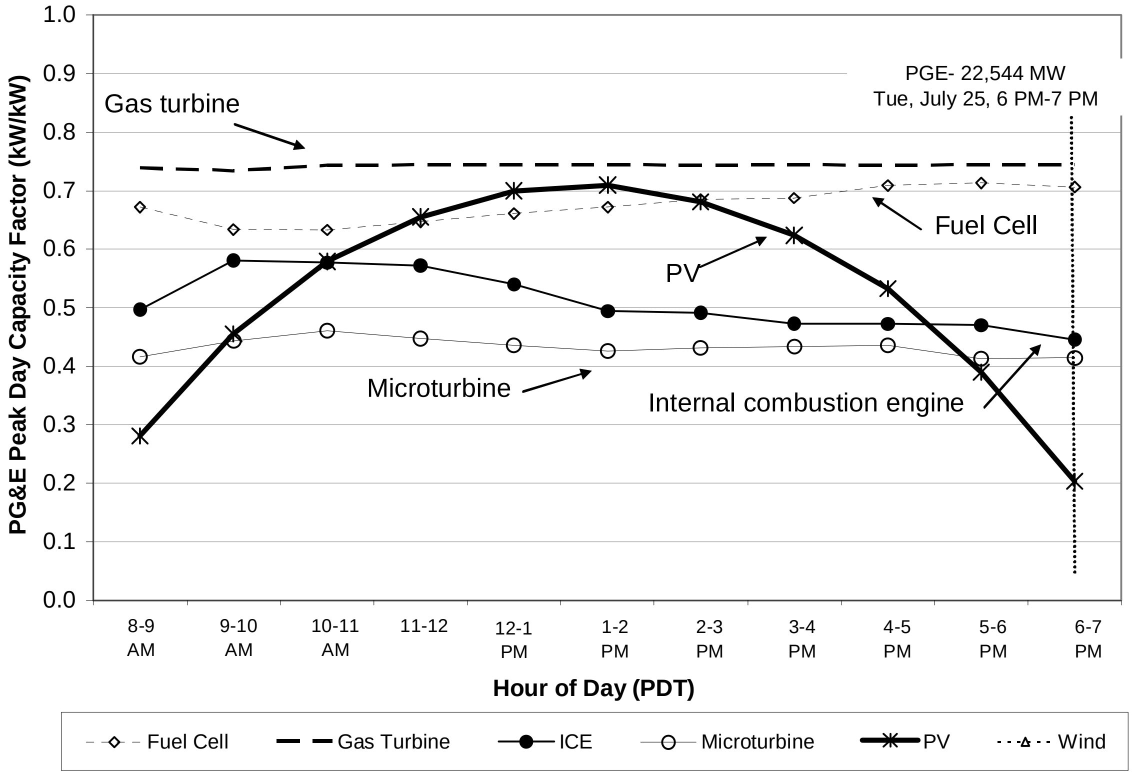
Elec PA	Peak (MW)	Date	Hour (PDT)
SDG&E	4,502	22-Jul-06	2 PM

Technology	On-Line Systems (n)	Operational (kW)	Impact (kW)	Hourly Capacity Factor (kWh/kWh)
FC	1	1,000	392	0.392
GT	0	0	0	
ICE	19	12,225	2,157	0.176
MT	15	1,622	322	0.199
PV	76	8,848	5,987	0.677
WD	0	0	0	
TOTAL	**111**	**23,696**	**8,858**	**0.374**

Of the three IOUs with SGIP facilities operating during the 2006 peak, SDG&E had the earliest peak, occurring at 2 pm on, Saturday, July 22, 2006. As a result of the earlier timing of SDG&E's peak demand, the PV peak capacity factor was 67 percent. However, the peak capacity factor for the single fuel cell operating in SDG&E during its peak was 39 percent. Similarly, IC engines and microturbines showed significantly lower peak capacity factors than their counterparts in PG&E and SCE; at 20 percent, nearly half the value. The unusual timing of SDG&E's peak hour on a weekend day may explain these low capacity factors. Onsite operators may have had reduced demand for both power and heat on a Saturday.

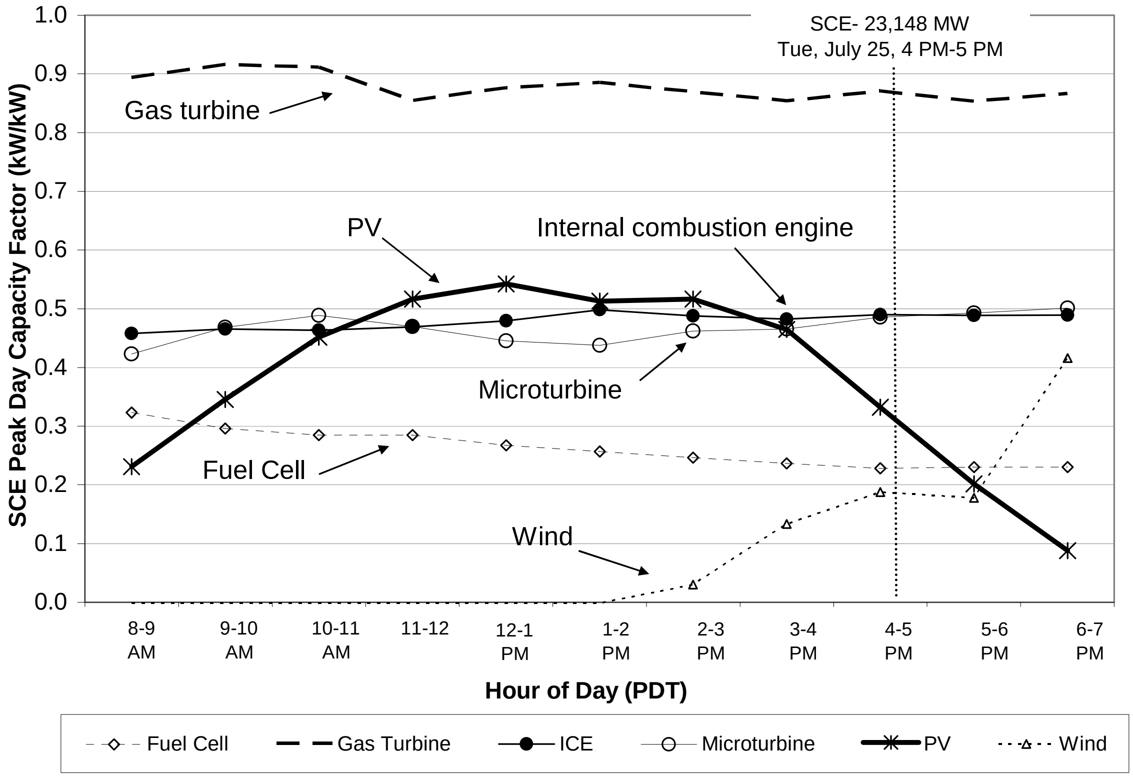
Figure 5-4 through Figure 5-6 plot profiles of hourly weighted average capacity factors by technology for the SGIP systems directly feeding the utilities on the dates of their respective peak demand. The plots also indicate the date and hour and value of the peak load for the electric utility. Note that the plots include only those technologies that were operational for the electric utility, so not all technologies appear for all electric utilities. Again, results presented for the peak days of the three individual electric utility do not strictly include all systems or only systems administered by the PA associated with the electric utility. Appendix A plots separately those technologies that can use natural gas versus renewable fuel.

Figure 5-4: Electric Utility Peak Day Capacity Factors by Technology – PG&E



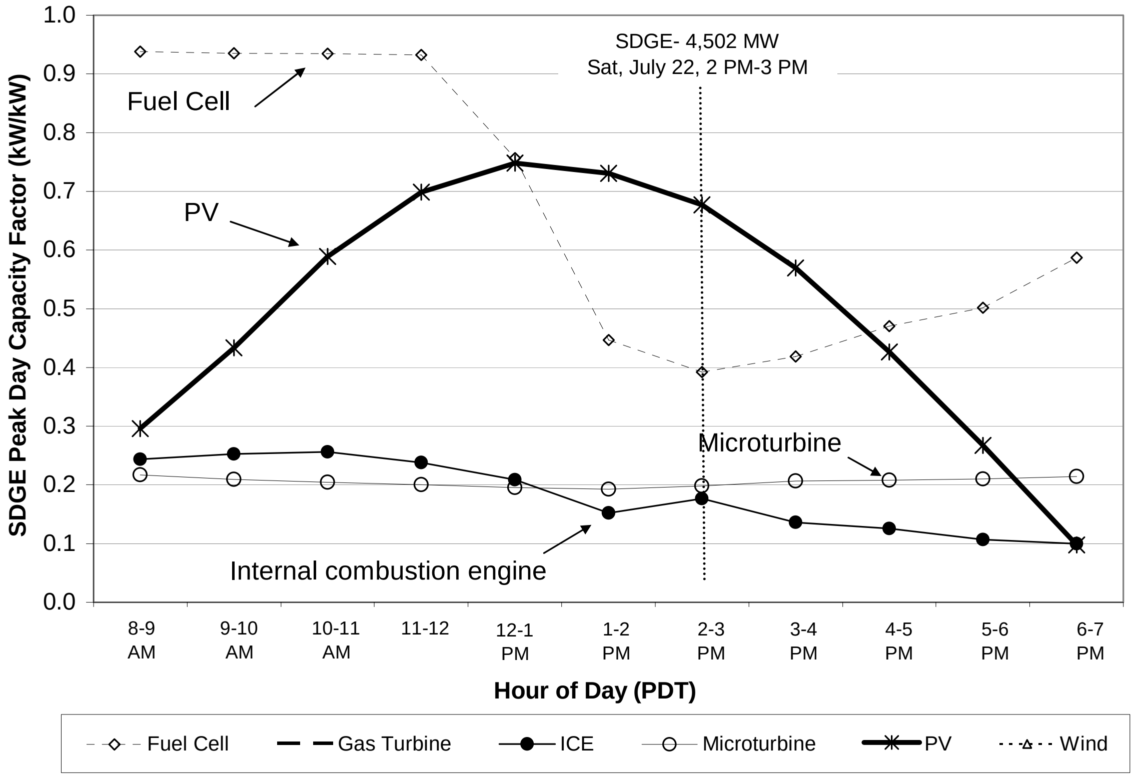
The hour by hour peak day capacity factor plot for PG&E reflects the almost flat generation profiles exhibited on average from natural gas-fired cogeneration facilities operating under the SGIP. For fuel cells and gas turbines, which operated at high capacity factors during the peak hour, this profile provided benefit to PG&E. However, the 40-45 percent capacity factors exhibited by microturbines and IC engines during the peak hour meant that as much as 60 percent of the rebated capacity of these technologies was not available when most needed. In the case of IC engines, the capacity factor decreased in the morning from a high of nearly 60 percent to a low of almost 40 percent by 6 pm. Because these results represent a capacity-weighted average, it is unclear what role individual cogeneration systems played in displacing peak demand at their respective customer sites.

Figure 5-5: Electric Utility Peak Day Capacity Factors by Technology – SCE



The hour by hour peak day capacity factor plot for SCE shows similar trends to that seen with PG&E. In particular, gas turbines exhibited a very high and flat capacity factor across the day, including the peak hour at 2 pm. IC engines and microturbines also showed a flat profile; staying consistently in the 40-50 percent range. The wind capacity factor picks up from essentially zero at 1 pm to nearly 20 percent by 4 pm, which is consistent with the diurnal wind patterns found with wind resource in the particular area of the wind systems located in that specific region of the SCE service territory.

Figure 5-6: Electric Utility Peak Day Capacity Factors by Technology – SDG&E



As indicated earlier, SDG&E's peak occurred on a Saturday. This may explain the unusually low hourly capacity factors observed for IC engines and microturbines. The high hourly capacity factor seen for PV at the 2 pm peak reflects the increased insolation available at that time of the day.

5.3 Transmission and Distribution Impacts

In addition to providing electricity over the course of the year and during times of peak demand, distributed generation (DG) technologies being deployed under the SGIP impact the distribution and transmission sections of California's electricity system. If DG facilities successfully displace electricity that would otherwise have to be provided to electricity customers during peak demand, they can reduce loading on the distribution and transmission lines. That reduced loading can potentially result in a decreased need to expand or build new transmission and distribution infrastructure, thereby saving utility and ratepayer monies. Moreover, by providing multiple pathways for electricity to be delivered to the grid, DG facilities can potentially lower risk of transmission outages, thereby increasing overall system reliability.

This section presents the impacts of SGIP facilities on the IOU transmission and distribution system during 2006. Data sources, methodology and detailed results of the transmission and distribution impacts analyses are presented in Appendix B. Distribution system impacts are discussed first, followed by transmission system impacts.

Distribution System Impacts

SGIP facilities are located at a utility customer's site with the intention of displacing all or a portion of the customer's electricity demand. As such, SGIP facilities are distributed generation (DG) systems that connect directly to the distribution side of the electricity system. Impacts to the overall transmission and distribution system are encountered first at the lower voltage distribution system. A number of DG facilities can be connected to a single distribution feeder. Impacts to the distribution feeder will increase as the cumulative capacity of DG facilities connected to a single distribution feeder increases.

Distribution Systems Analysis Approach

Distribution system impacts were assessed by comparing SGIP hourly generation profiles against hourly distribution line loadings. Line loadings were limited to those distribution lines serving utility customers hosting SGIP DG facilities. Metered electrical net generator output (ENGO) interval data collected for 313 metered SGIP DG facilities were isolated to the specific date and hour of the 2006 and 2005 summer peak conditions for each IOU participating in the SGIP.[6] Similarly, distribution line loadings corresponding to the same peak day and hour were isolated to enable identification of SGIP output coincident with peak loading at each substation. The coincident SGIP peak load was then summarized by feeder type, IOU, and climate zone. This allowed extrapolation of the observed coincident peak load from interval-metered SGIP facilities to the entire SGIP DG population.

[6] Although 2006 impacts are the focus of this study, both 2006 and 2005 transmission and distribution impacts were evaluated.

Table 5-10 shows the breakdown of metered SGIP DG facilities and distribution feeders by climate zone and IOU service territory. The PG&E Coast group includes 31 generators in climate zones 2-5. The SCE Coast group includes 128 generators in climate zones 6-10 while the SDG&E Coast group includes 112 generators in the same zones. Due to a limited number of generators, it was not possible to separate the inland climate zones by utility. The inland climate group includes a total of 42 generators in climate zones 11-15. Since we do not expect significant differences by utility in the central valley we do not expect this to affect the robustness of the analysis.

Table 5-10: Number of Metered Observations by Climate Zone and IOU (2005/2006)

	Climate Zone	PG&E	SCE	SDG&E	Total
North Coast	2	6			6
	3	22			22
	4	2			2
	5	1			1
	Sub Total	*31*			*31*
South Coast	6		23		23
	7			90	90
	8		42	1	43
	9		33		33
	10		30	21	51
	Sub Total		*128*	*112*	*240*
Inland	11	8			8
	12	15			15
	13		12		12
	14		4	1	5
	15			2	2
	Sub Total	*23*	*16*	*3*	*42*
	Total	31	128	112	313

In addition to climate zone, the analysis also grouped installations by the type of customers served by the distribution system. However, even with a threshold as low as 50% of energy sales to a specific class, a large number of feeders in the system could only be categorized as mixed. The distribution of the feeder peak hours by feeder type across all of the utilities is shown in Figure 5-7. The commercial and industrial feeders tend to peak earlier in the day, with hour ending (HE) 13 being the most common peak hour. Residential and mixed feeders tended to peak in the evening (HE 17 & 18) or at night (HE 22).

Figure 5-7: Distribution of Feeder Peak Hour by Customer Types

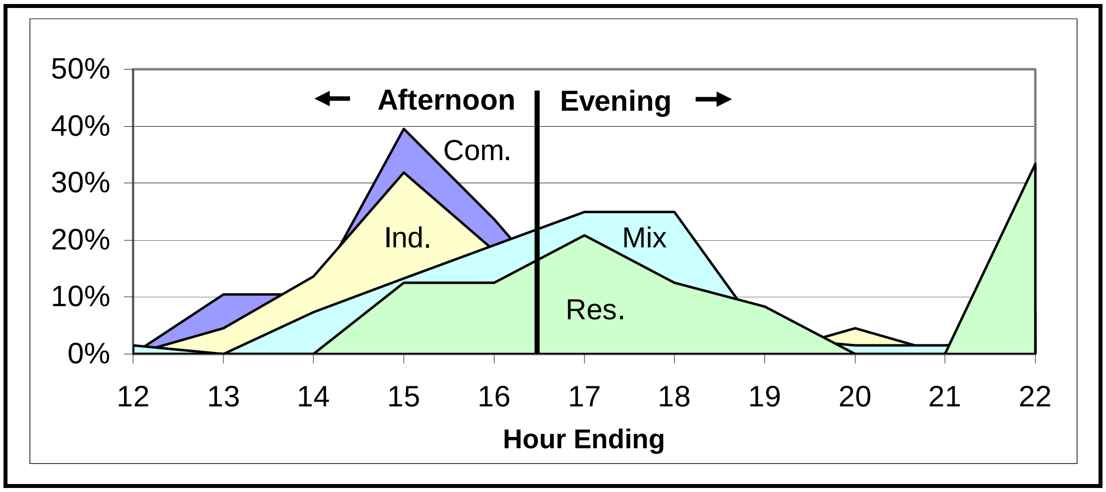
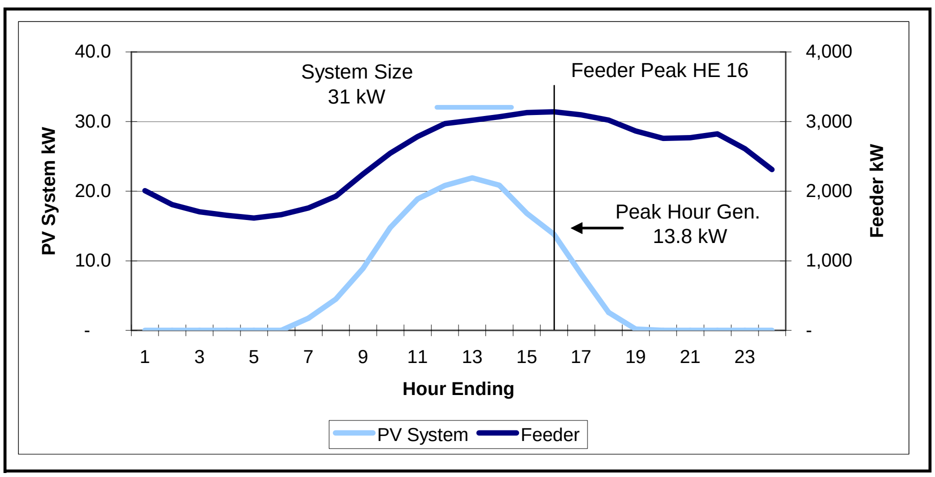


Figure 5-8 illustrates the concept of comparing SGIP DG generation to peak loading on a single distribution feeder. In this example, the feeder has a load shape typical of residential loads, peaking at a demand slightly above 3,000 kW at Hour Ending (HE) 16. In this example, the SGIP generator is a 31 kW PV system with peak generation of 21 kW at HE 13. During the feeder peak at HE16, however, the PV system is only producing 13.8 kW. Consequently, the 13.8 kW of PV generation coincident with the peak loading at HE 16 is used in this analysis of distribution impacts.

Figure 5-8: Example of Feeder Peak Hour Generation for a PV System



Distribution System Analysis Results

In her May 18, 2006 ruling, the Administrative Law Judge (ALJ) asked for an assessment of the "impacts of distributed generation investments on utility grid and transmission planning".[7] This distribution analysis provides an impact assessment for 2005 and 2006.

[7] CPUC Ruling R06-03-004

The distribution analysis also provides a "look-up" table of distribution peak load coincidence factors to help facilitate integration of DG in utility planning. In addition, the analysis provides an approach to evaluate the level of certainty that the SGIP output will provide distribution peak load relief. This information is based on the measurements of the SGIP installations in place, and should facilitate the integration of SGIP in utility system planning as the SGIP continues to expand and penetration of distributed generation increases in California.

The distribution analysis was designed to answer three main questions:

1. **Measured Impact**: What was the measured distribution system impact in 2005 and 2006 for each utility?
2. **System Planning Impact**: How can we incorporate the impacts of distributed generation on distribution system planning?
3. **Cost Savings**: Have there been any distribution system cost savings associated with SGIP?

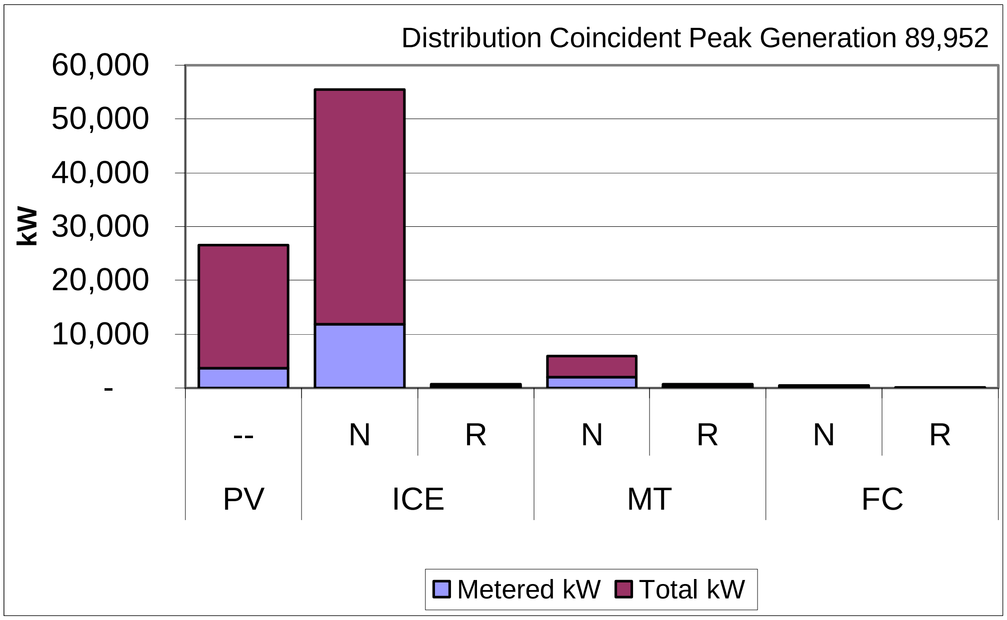
<u>1. What was the measured distribution system impact for each utility?</u>

The estimated distribution peak load reduction associated with SGIP facilities in 2006 in the three IOU service territories was 46.1 MW, 37.1 MW and 6.8 MW for PG&E, SCE and SDG&E respectively, totaling 90.0 MW for California.[8] These results include only the 313 systems which had sufficient metered data available during the peak day and hour of the corresponding feeder or substation.

Figure 5-9 shows the coincident peak load reduction by SGIP technology program-wide in 2006. As described earlier, the metered kW is based on a direct comparison of metered SGIP output and the measured loadings on the distribution feeder or substation serving the customers with the SGIP installation. Not all SGIP installations have interval metering and distribution loading information. Therefore, a set of distribution peak load factors was developed (see Table 5-11, below) and used to estimate the total coincident distribution peak load reduction.

[8] Section 5.2 refers to a coincident peak generation for SGIP facilities at the 2006 peak of 103 MW. The 90 MW of coincident peak reduction referred to here represents coincident peak for the family of distribution feeders. As distribution feeders can have a peak loading at a different day and hour from the IOU peaks, this can lead to a difference in peak loading definitions. In addition, differences can also be due to lack of distribution feeder loading data.

Figure 5-9: Distribution Coincident Peak Load Reduction by Technology – California 2006



Metered kW	3,636	11,914	360	2,024	203	0	0
Total kW	26,516	55,515	744	5,975	688	467	67
Metered #	78	55	3	28	4	1	1
Total #	569	165	9	81	16	9	2

Notes: 'metered kW' is the distribution peak load reduction directly metered, 'total kW' is the estimated total distribution peak load reduction, 'Metered #'is the number of SGIP installations metered, 'Total #' is the total number of SGIP installations

<u>2. How can the impacts of distributed generation be integrated in distribution system planning?</u>

The most important factor for achieving distribution savings from distributed generation is being able to anticipate the peak load reductions resulting from the DG generation, and then integrating this information in utility planning and operation decisions. This requires knowledge of the location of SGIP DG installations, the expected load reductions, and the level of certainty associated with the expected peak load reductions. We have developed a "look-up table" that shows the relationships between the measured distribution coincident peak load reduction across different SGIP technologies, utilities, feeder types and climate zones based on measured data in 2005 and 2006. The "look-up table" should provide utility planners with additional insights into DG impacts on distribution lines which they can begin to incorporate in their distribution planning decisions.

Table 5-11 is the "look-up table" that reports the distribution peak load coincident factors based on measured SGIP installations in 2005 and 2006. The peak load reduction factor represents the effective peak load reduction that can be expected on a particular type of feeder from the various types of DG technologies. For example, PV SGIP installations located in SCE coastal climate zones on feeders that peak in the afternoon (prior to HE 16) demonstrated average peak reduction effectiveness equal to 46 percent of the rebated PV capacity. This means that for each kW of rebated PV capacity in the SCE coastal zone, it will provide 0.46 kW of peak reduction in the distribution system. Program-wide peak reduction effectiveness factors were also developed for each technology. The overall coincident peak load impacts measured across the SGIP are 35% (PV), 48% (ICE), 44% (MT), and 9% (FC). The categories developed to report the coincidence factors are a balance between what is the most useful and having enough observations to have confidence in the results. Further investigation of PV SGIP installations by tilt and climate zone are reported in Appendix B.

Table 5-11: Distribution Coincident Peak Load Reduction as a Percent of Rebated Capacity – California 2005 & 2006

		PV	ICE		MT		FC	
		--	N	R	N	R	N	R
PG&E Coast	Afternoon	56%	85%					
	Evening	30%						
SCE Coast	Afternoon	46%	65%		44%			
	Evening	6%	48%		52%			
SDG&E Coast	Afternoon	42%	33%		40%			
	Evening	1%						
Inland	Afternoon	63%	29%					
	Evening	26%						
Total by Technology/Fuel		35%	50%	12%	50%	23%	16%	0%
Total by Technology		35%	48%		44%		9%	

Notes: Climate Zones

PG&E Coast (CEC Title 24 Climate Zones 2, 3, 4, 5)

SCE Coast (CEC Title 24 Climate Zones 6, 7, 8, 9, 10 in SCE service territory)

SDG&E Coast (CEC Title 24 Climate Zones 7, 8, 10 in SDG&E service territory)

Inland (CEC Title 24 Climate Zones 11, 12, 13, 14, 15 for all utilities)

Distribution Peak Hour

Afternoon (Peak occurs on Hour Ending (HE) 16 or earlier)

Evening (Peak occurs after HE 16)

<u>3. Have there been any distribution system cost savings associated with SGIP?</u>

The May 18, 2006 ALJ Ruling requests an evaluation of cost savings associated with performance, reliability, and operations. The results of this analysis were completed in two steps: (1) identifying the potential areas of cost reductions associated with SGIP installations, and (2) estimating the potential magnitude of any savings.

There have been numerous studies completed that list and quantify the benefits of distributed generation and distributed resources, but these are typically planning studies[9]. Very few M&E studies quantify distribution system benefits based on measured savings.

Distribution system benefits are typically due to three types of distribution improvements: (1) performance improvements; (2) reliability improvements; and (3) operations improvements. Performance improvement benefits can be quantified as a reduction in losses, improvement in voltage profile, and improvement of power quality. Reliability improvement can be quantified as the reduced capital investment necessary to meet the established distribution reliability criteria with SGIP in place. Operations improvement can be quantified in terms of reduced crew time and maintenance costs.

Given the available data, this study focused on the two categories of benefits that represent the largest benefit categories: performance improvements based on reduced distribution system losses; and reliability improvements based on reduced distribution capital expenditures. Information to evaluate other potential sources of benefits such as improvement in voltage profiles, power quality, reduced crew time, and maintenance costs was not readily available. In addition, these potential benefits are difficult to attribute specifically to SGIP facilities and in some cases may be very small.

Table 5-12 shows the estimated value of distribution loss savings from SGIP facilities in 2005 and 2006 by IOU service territory. At over $2 million per year, the total value is similar for 2005 and 2006, with a slight decrease in 2006 due to less generation identified overall in 2006 than 2005. While we are not certain, this reduction is likely due to higher natural gas prices for natural gas powered CHP units. The calculation is simply the energy generated times the distribution loss factor for each utility times the estimated wholesale value of energy.

[9] For comprehensive assessment of the value of distributed generation, see Energy and Environmental Economics, Inc and Distributed Utility Associates, Joe Iannucci.

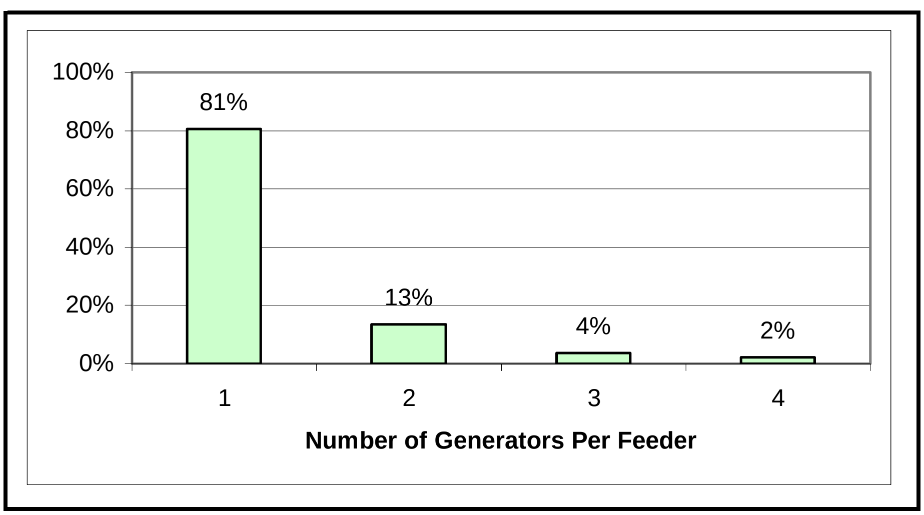
Table 5-12: Estimated Value of Distribution System Loss Savings

Year	Utility	SGIP Generation (MWh)	Distribution Loss Savings (MWh)	Loss Savings ($/year)	Total Savings ($/year)
2005	PG&E	432,451	15,003	$ 864,512	
	SCE	625,546	14,707	$ 861,491	
	SDG&E	249,062	10,669	$ 624,948	$ 2,350,951
2006	PG&E	460,797	15,986	$ 921,177	
	SCE	478,397	11,247	$ 658,840	
	SDG&E	247,761	10,613	$ 621,682	$ 2,201,699

A potentially larger benefit is the distribution capacity value associated with the SGIP installations. A key driver for providing distribution capacity value is achieving sufficient peak load reductions to defer planned capital additions without exceeding the N-1 peak load ratings on distribution system equipment. This requires enough distribution coincident peak load reduction to defer investments.

To evaluate the potential for capital investment deferrals, the project team tabulated the penetration of SGIP installations per feeder, and then the total amount of measured load reduction. The percentage of feeders serving one or more SGIP generators is shown in Figure 5-10.

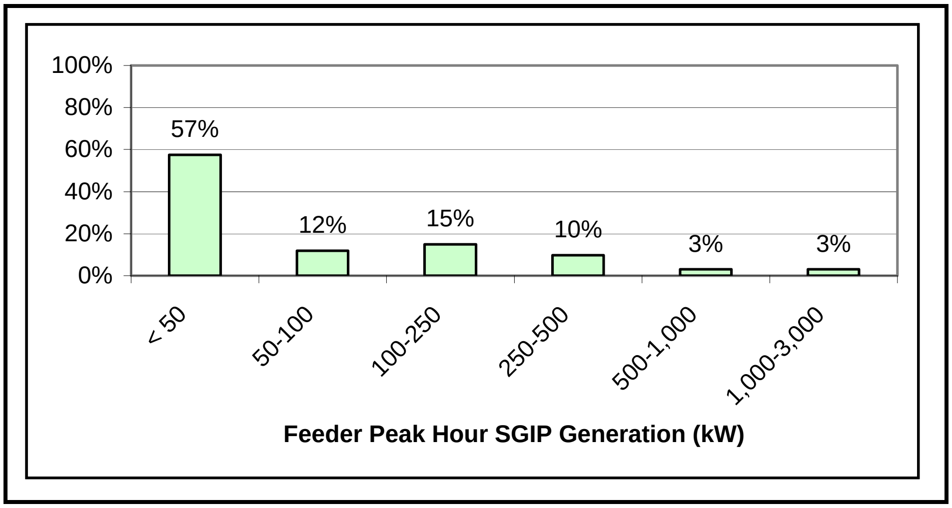
Figure 5-10: Number of SGIP Generators per Distribution Feeder



Based on the available data, 81% of distribution feeders serving a customer with a SGIP generator have a single SGIP installation. Approximately 2% of feeders serving an SGIP generator have four SGIP generators.[10]

The amount of peak load reduction per substation or feeder is also critical for evaluating the potential for distribution capacity savings. The percentage of substations or feeders with varying amounts of observed distribution peak load reduction is shown in Figure 5-11. Of the feeders evaluated, 57% of those with SGIP installations had a peak load reduction of less than 50kW. Only 3% of substations or feeders had load reductions from 1MW to 3MW.

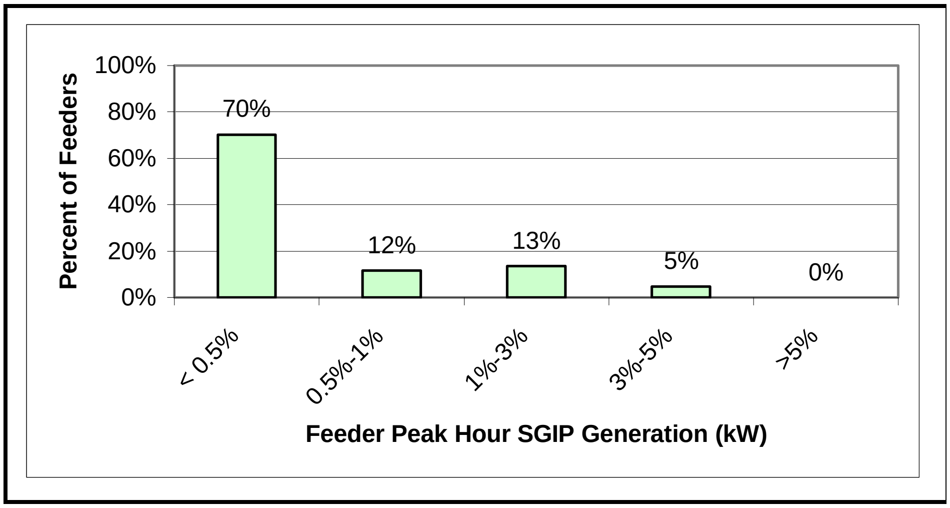
Figure 5-11: Feeder Peak Reduction as Percentage of All Measured Feeders



The amount of distribution load reduction achieved with SGIP reduction can also be expressed as the percentage of feeders that have achieved 'significant' peak load reductions. The frequency of different levels of peak load reduction achieved in 2006 is shown in Figure 5-12. In 2006, no feeder or substation had a measured peak load reduction of greater than 5%. The results from 2006 suggest that SGIP generators were not running during the distribution peak hour in 2006. The reason for the generation was not running is not known, but could be due to high natural gas prices, a forced outage, or something else.

[10] Note that one utility submitted data for substations rather than feeders and that some of the substations with multiple SGIP generators will likely have numerous feeders. Therefore, even if there are four distributed generators, they may not be connected to the same feeder or substation transformer.

Figure 5-12: Distribution of SGIP Generation as Percent of Feeder Peak – 2006



Taken together, the results of the distribution capacity evaluation indicate that there is not a sufficient penetration of SGIP distributed generators to provide distribution capacity value. With greater penetration overall, or targeted penetration on a specific distribution system in danger of an overload, it would be possible to capture distribution capacity savings.

In addition to limited penetration of SGIP facilities within the distribution system, a number of other factors contribute to a lack of distribution capital savings. One of these is that the SGIP generators operate independently of the distribution system. Therefore, the SGIP owner does not know when the distribution peak is, nor do they have any incentive to operate during the peak even if they did know. In fact, the current SGIP rules prohibit an additional incentive to operate during the local capacity peak. Similarly, the distribution utility planners do not necessarily know which SGIP generators are being served by overloaded equipment, likely because the penetration of SGIP generators is not currently high enough to warrant close attention for capacity planning at the distribution level. In addition, SGIP owners choose where to install their systems, not the utility; therefore they are not a concentrated number of installations in a single area of need that could provide significant load relief on a particular overloaded feeder or substation.

Transmission System Impacts

Customer self-generation can potentially improve transmission and distribution system reliability. The transmission reliability benefits depend on the location and size of self-generation; penetration potential; capacity availability at time of system peak and other attributes. As load reduces due to self-generation on the distribution network, there is a corresponding reduction on the distribution transformers, sub-transmission lines, transmission substations and the ultimately the high voltage lines. However, the system needs very high penetrations to provide significant benefits to the high voltage transmission lines. The major benefit is a reduction in the loading of substation equipment (including transformers) and the sub-transmission lines (line voltages below 230 kV). Any delays or elimination of upgrades in the transmission system due to self-generation saves electric customers money.

Due to the relatively small capacities of DG systems, impacts are more easily observed at the distribution level than at the transmission level. However, as the number of DG facilities increases, the cumulative capacity increases the likelihood for significant impact at the transmission level. For this reason, the approach was taken to model the aggregated capacity (MW) of SGIP DG facilities at each substation. The assumption was made that SGIP DG facilities act to reduce loading on distribution and transmission lines. Consequently, if generation from DG facilities is not available, then total load at the substations is higher by the otherwise contributed capacity of the aggregated DG facilities. The transmission substation configuration includes both the SGIP DG facility capacity and a corresponding load equal to the SGIP DG capacity. When a DG facility is considered out of service under a contingency analysis case, then the load at the substation increases because the DG facility is not available to offset the load. This representation simulates the benefits provided by DG facilities acting to reduce loading on substations and transmission lines.

<u>Transmission System Analysis Approach</u>

The methodology for evaluating the transmission benefits of DG facilities located at different locations is termed the Aggregated MegaWatt Contingency Overload (AMWCO). Power flow simulations are completed under first contingency (N-1) conditions. One at a time, each power flow element (e.g., a transmission line, transformer, or generator) is temporarily removed from service and a power flow simulation is completed. This process is repeated for each element in the power flow case. For an N-1 simulation of the California transmission system, this can represent up to 7,000 simulations completed. One or more of these individual simulations may cause an overload on one or more elements. The percent overload of the element is weighted by the number of outage occurrences and the percent overload. The summation of the weighted overloads is the AMWCO. The difference between the AMWCO for the base case and each DG facility case divided by the capacity of the installed DG is the Distributed Generation Transmission Benefit Ratio (DGTBR). For the cases with and without the DG modeled, the AMWCO is calculated. The difference between the two AMWCO values divided by the DG capacity determines the DGTBR. A negative DGTBR represents an improvement in system reliability. A positive DGTBR indicates a probable decrease in system reliability. This approach is based on a similar approach used for assessing transmission impacts due to integration of renewable energy facilities[11].

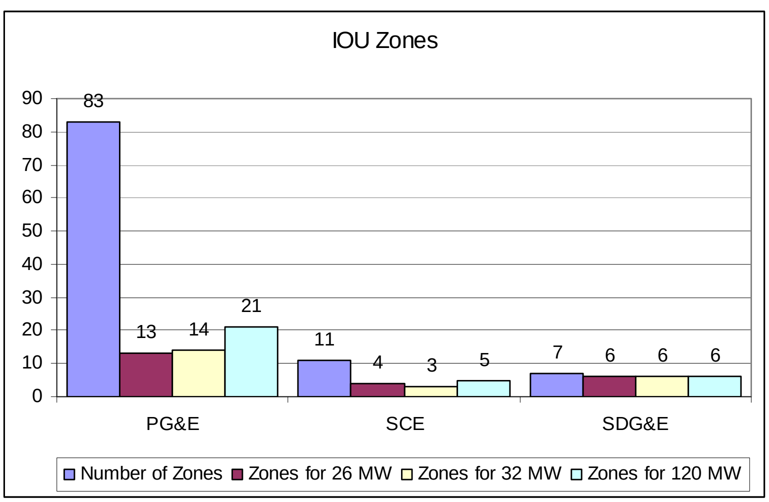
[11] California Energy Commission, "Strategic Value Analysis for Integrating Renewable Technologies in Meeting Renewable Penetration Targets," CEC-500-2005-106, June 2005

Three power flow scenarios were conducted to assess transmission impacts of aggregated DG capacities. The first scenario assessed the impact of all of the SGIP DG resources on a state-wide basis. The first power flow simulation excludes all of the DG facilities. A power flow simulation was completed for approximately 7,000 first contingency (N-1) conditions. The first contingency condition represents an outage of one transmission line or one generator. To model every line and transformer outage requires 7,000 different simulations. The second case included the SGIP DG resources. The number of simulations was slightly larger than the first simulation due to the increase in generators represented by the SGIP DG resources. The DGTBR value was determined by subtracting the AMWCO value from the first case from the AMWCO from the second case and dividing by the aggregated DG value. A negative value indicates that the aggregated DG provides a transmission reliability value to the statewide electricity system.

The second scenario assessed the impacts to each IOU. The same two simulations were completed as described above except that instead of a state-wide study, the studies concentrated on each utility system. The DGTBR was calculated using the same method employed for the state level scenario.

Each IOU divides its service area into transmission zones. Consequently, the third scenario examined the transmission impact to IOU transmission zones containing SGIP DG resources. Figure 5-13 shows the total number of zones for each IOU and the number of zones that includes at least one DG facility.

Figure 5-13: IOU Transmission Zones in California



Transmission System Analysis Results

There was approximately 32 MW of SGIP DG resources with peak generated metered during the 2006 peak day and hour. The distribution of SGIP DG resources examined in the transmission analysis is shown in Figure 5-14. The location of these resources is approximated since their exact GIS locations are unknown. Instead, locations on the map reflect the approximate location of the connection point of the SGIP DG facilities to their associated transmission bus.

Figure 5-14: Locations of SGIP Facilities Analyzed for 2006 Transmission Impacts

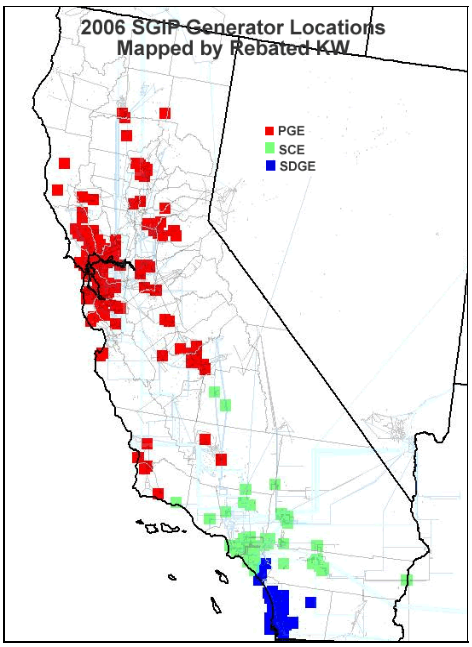


Figure 5-15 shows the distribution of the 32 MW of peak coincident capacity of the SGIP DG for the three IOUs during the 2006 peak. The number of SGIP DG facilities for the IOU and for the IOU transmission zones should be the same as the utility assigned the DG facilities to specific zones. As seen, the majority of the SGIP DG facilities showing generation coincident to the summer 2006 peak are located in SCE service area.

Figure 5-15: Distribution of SGIP DG during 2006 Peak

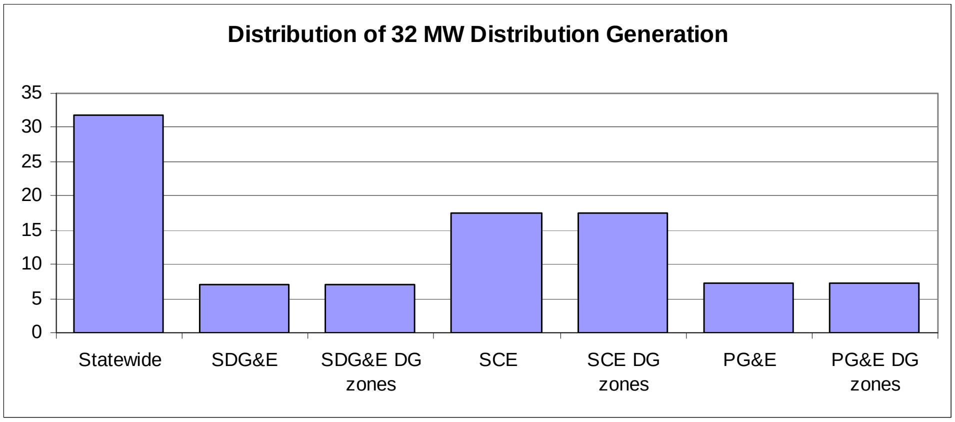
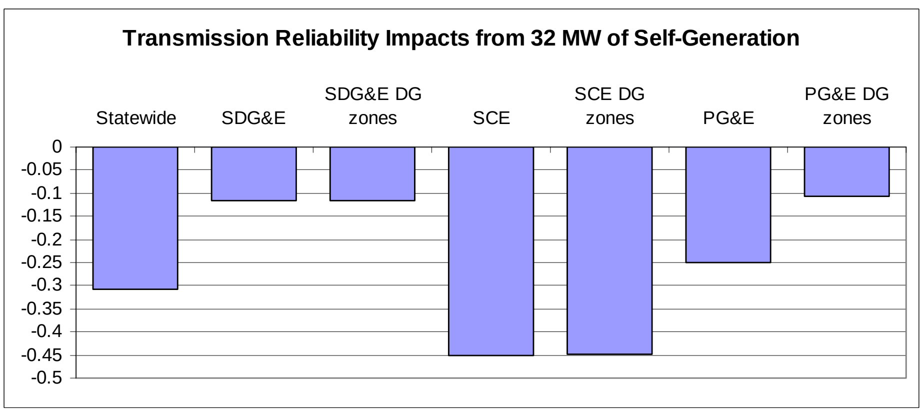


Figure 5-16 shows the results of the DGTBR analysis for the 2006 summer peak. Because DG facilities act to reduce load at the load centers, they should show some degree of transmission benefit. As expected, the DGTBR values are negative across all scenarios for the summer 2006 peak.

Figure 5-16: Transmission Reliability Impacts for 2006 Peak



The magnitude and distribution of the DGTBR values reveals several observations. SCE has the largest number of DG facilities that contributed generation during peak demand. As a result, the DGTBR benefit is expected to be higher for SCE than for other utilities; and in fact is nearly twice the value for any other IOU. As there is not a large difference between the total number of zones and the number of zones with DG facilities, the DGTBR is expected to be the about the same in the SCE transmission zones.

Almost every zone in the SDG&E service area contains DG facilities. As such, the DGTBR is expected to be the same in the SDG&E transmission zones. The DGTBR values are negative and provide a transmission benefit to SDG&E even though the self-generation is only 7 MW. For 2006, the SDG&E DGTBR value means that for every MW of SGIP DG on line during the peak, it provided 1.1 MW of increased system reliability.

PG&E's results may be the most interesting of the group. As shown in Figure 5-13, PG&E is divided into 83 transmission zones but only 14 contain DG facilities. The DGTBR values should therefore be different for PG&E as compared to the zones having equal DG resources. The bar charts shown in Figure 5-16 confirm that the DGTBR values are significantly different in PG&E. The concentration of DG facilities across fewer zones results in the DGTBR being lower within the zones as compared to the total PG&E system. This result occurs because there is less load in the zone and fewer transmission lines to impact the DGTBR under contingency analysis. By inadvertently compressing DG facilities into fewer zones, the DGTBR may not always produce consistent results.

The total state-wide DGTBR is also shown in Figure 5-16. Even though the total aggregated capacity of the SGIP DG facilities is only 32 MW out of the 42,000 MW of demand occurring under the 2006 summer peak conditions, these DG facilities were still found to provide overall DGTBR benefits to the system.

For sensitivity purposes, DGTBR analyses were conducted for three different penetration levels of DG. One case represented the amount of SGIP DG (26 MW) that was metered for the 2005 peak conditions. Another case involved the amount of SGIP DG (32 MW) that was metered for the 2006 peak conditions. The last case assumed that all 120 MW of SGIP available in 2006, even though not actually available, was available for peak conditions.

Figure 5-17 shows the distribution of SGIP DG for the three DG penetration cases. The distribution of SGIP DG resources under the 120 MW case is based on actual IOU distributions in 2006.

Figure 5-17: Distribution of SGIP DG under Different Penetration Cases

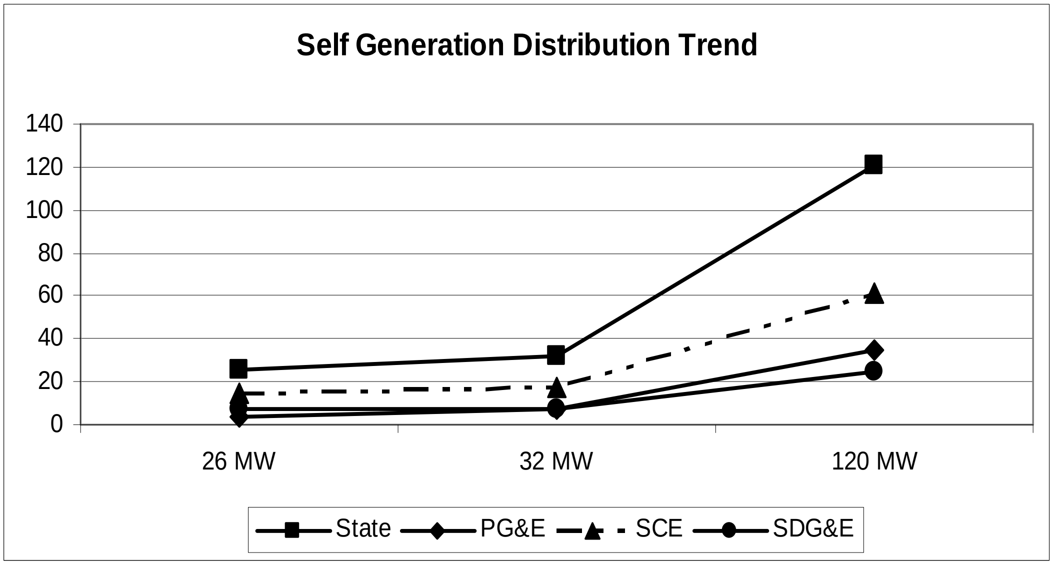
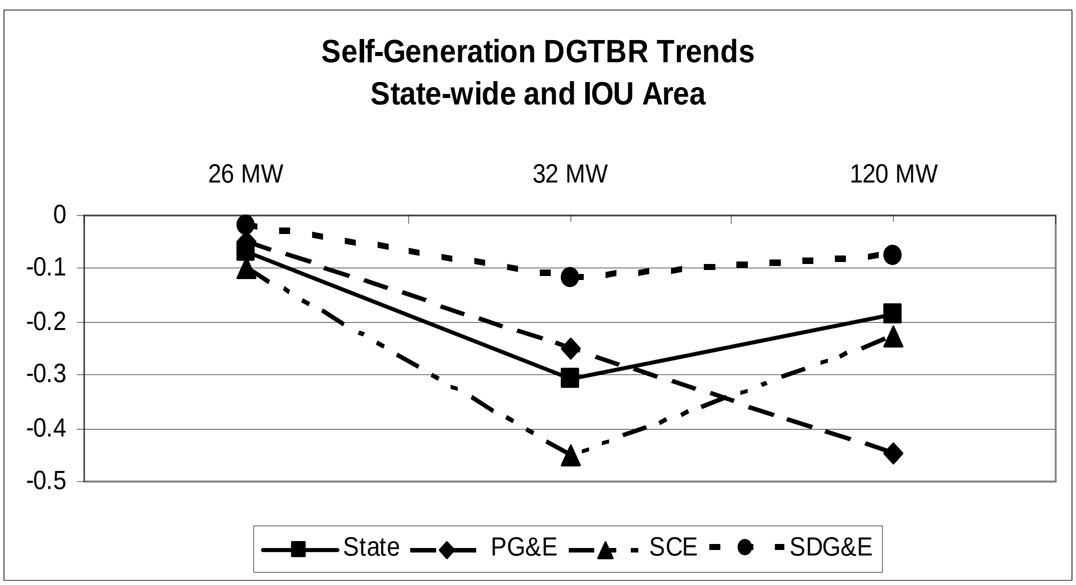


Figure 5-18 shows the DGTBR values by IOU area for the three penetration cases on one graph. There is a drop in the DGTBR from the 26 MW DG penetration to the 32 MW DG penetration for all three IOUs and for the state-wide scenario. What is interesting and the most confusing is the decline in the DGTBR from the 32 MW scenario to the 120 MW scenario for the state-wide, SCE and SDG&E. There is consistency in the slope of the DGTBR lines for the state-wide, SCE and SDG&E results. Since the DG penetration levels are so low compared to the IOU loads, the changes in the DGTBR are almost undetectable.

Figure 5-18: Results of DGTBR Impacts under Different Penetration Cases



The PG&E results for the three penetration cases are more consistent with what would have been expected. The DGTBR continues to increase in the negative direction indicating that the higher DG penetrations continue to improve system reliability.

From a transmission perspective, the SGIP DG facilities were found to provide direct benefits to the sub-transmission and transmission networks by reducing load at the load centers. Even on a transmission system that has a total connected load of over 40,000 MW, the methodology used in this analysis can calculate the transmission benefits for only 32 MW of self-generation. The IOU representation of their transmission system into zones allows for detailed power flow analysis into sub-regions. Because of the small penetration of DG capacity in the system, the DGTBR value is relatively small. However, the results seem to indicate that higher penetrations of DG capacity coincident with peak demand would result in higher DGTBR values.

Given the uncertainties associated with modeling of aggregated DG capacity at low penetration levels, the actual impacts cannot be accurately determined until a higher penetration of DG capacity is achieved along with a better understanding of the availability of DG facilities at time of peak. The analysis described in this study concentrates on the summer peak time period only. To improve the analytical results and conclusions, additional seasons such as spring and fall should be considered along with a time step analysis of self generation over a pre-determined time period.

5.4 Efficiency and Waste Heat Utilization

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) 216.6[12] requires that participating nonrenewable-fueled fuel cells and engines/turbines meet minimum levels of thermal energy utilization and overall system efficiency.

PUC 216.6(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 216.6(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 5-13.

Table 5-13: Program Required PUC 216.6 Minimum Performance

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

SGIP facilities use a variety of means to recover heat for useful purposes, and 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 5-14, which includes all projects on-line through December 2006.

Table 5-14: End-Uses Served by Recovered Useful Thermal Energy (Total n and kW as of 12/31/2006)

End Use Application	On-Line Systems (n)	On-Line Capacity (kW)
Heating Only	182	69,935
Heating & Cooling	58	35,526
Cooling Only	28	20,673
To Be Determined	20	23,171
Total	288	149,305

PY 2005/06 PUC 216.6 Compliance

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

12 PUC 216.6 has replaced PUC 218.5; however the requirements remain the same.

the useful recovered heat. Actual operating efficiencies from these metered systems were used to estimate heat recovery from unmetered systems where electricity production data were available. Results are summarized in Table 5-15.

Table 5-15: Cogeneration System Efficiencies (n=288)

Technology	n	216.6 (a) proportion	216.6 (b) Efficiency	Overall Plant Efficiency
Fuel Cell	11	43%	55%	70%†
IC Engine	181	42%	39%	50%
Microturbine	96	50%	28%†	37%†

* [a] indicates confidence is less than 70/30. † indicates confidence is better than 70/30. No symbol indicates confidence is better than 90/10.

At least 10 months of operating data were available for 21 systems. In over 50 other cases less than 10 months of data were available for 2006. Because the basis of the PUC 216.6 proportions and efficiencies are annual, when at least nine 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 and estimated data collected to date suggest that roughly 17 out of 288 cogeneration projects achieved the 216.6 (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 or estimated for 11 fuel cell projects, all of which satisfied the requirements of PUC 216.6 (a) and PUC 216.6 (b) system efficiency

One of the fundamental objectives of the SGIP is to provide power at times of peak demand. Electrical production results were provided earlier in this section. Heat recovery results were produced specific to each of the pertinent peak days. Figure 5-19 provides normalized heat recovery by technology during the CAISO peak day. Results for each electric IOU are provided in Figure 5-20 through Figure 5-22.

Figure 5-19: Heat Recovery Rate during CAISO Peak Day

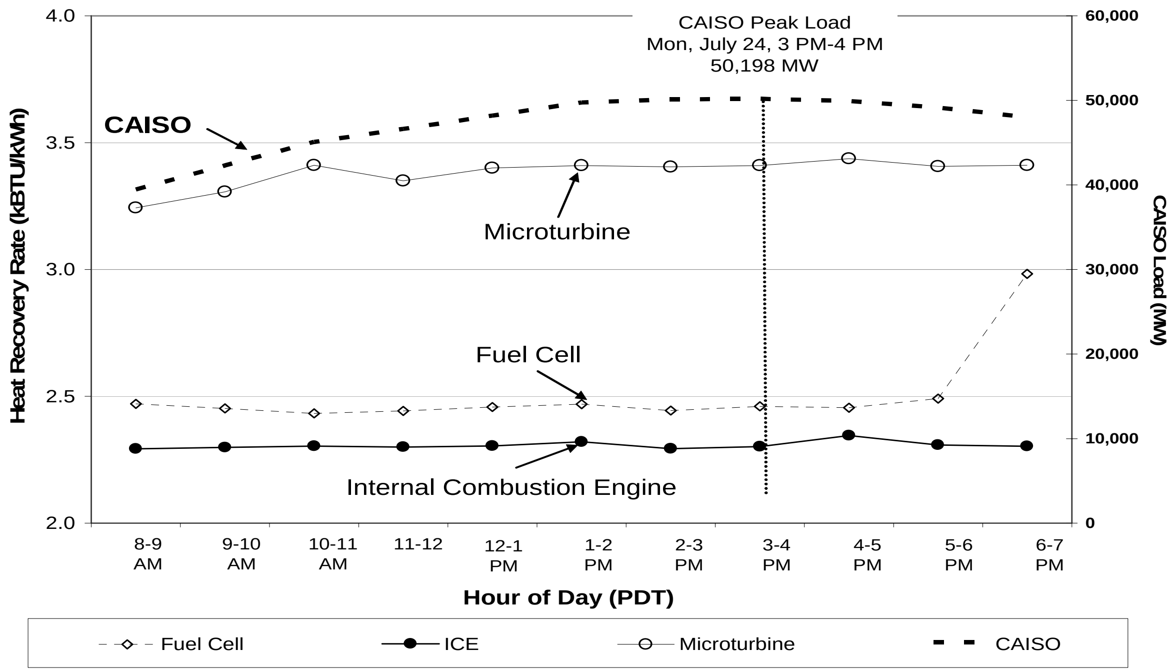


Figure 5-20: Heat Recovery Rate during PG&E Peak Day

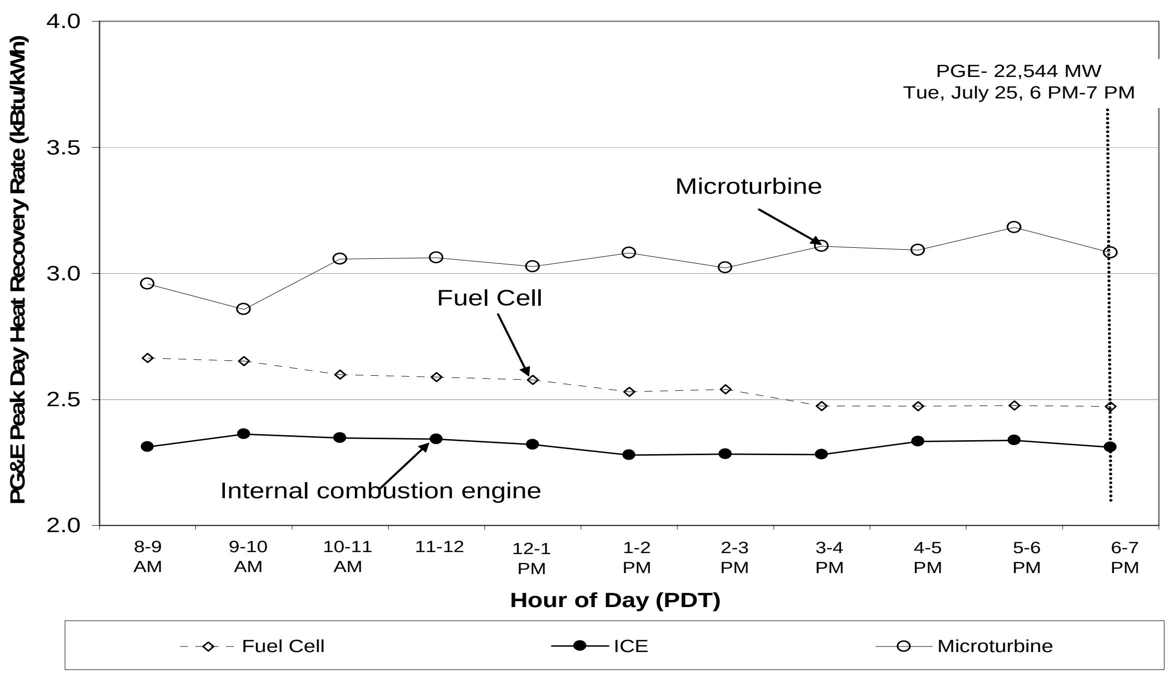


Figure 5-21: Heat Recovery Rate during SCE Peak Day

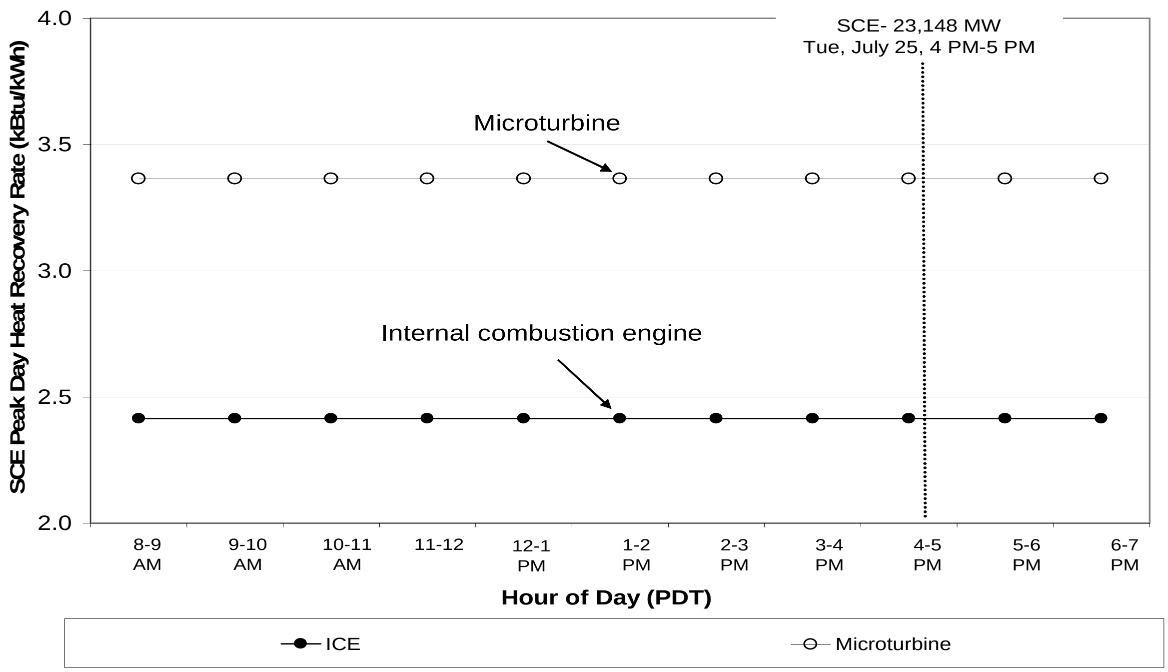
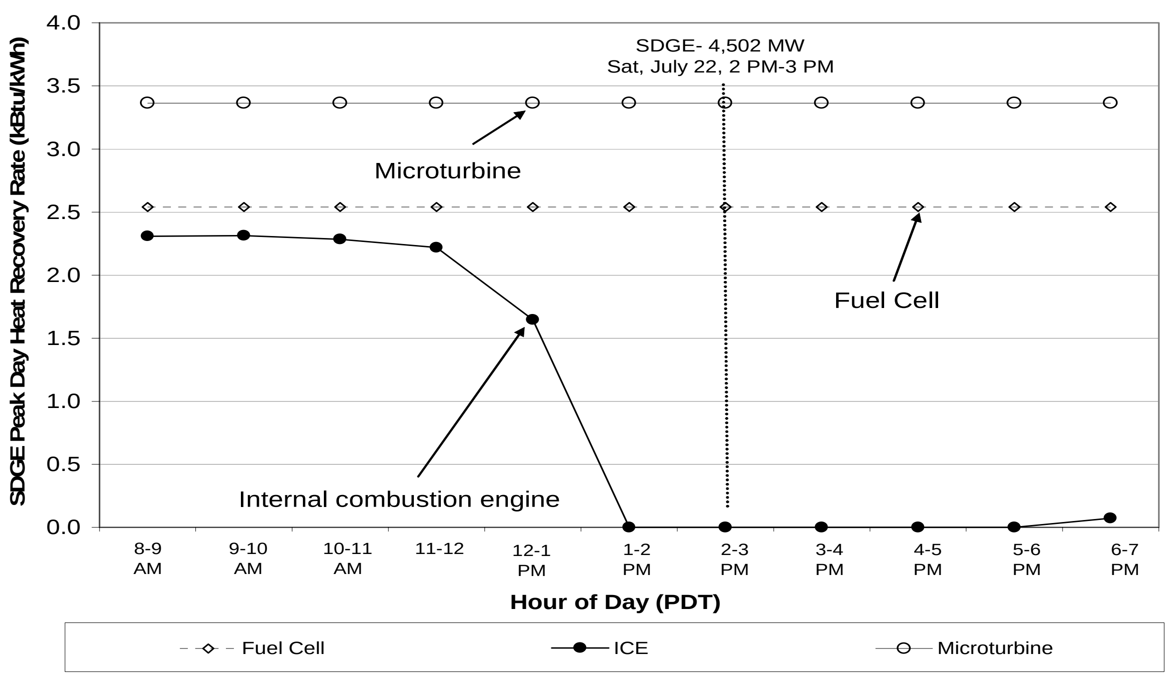


Figure 5-22: Heat Recovery Rate during CCSE Peak Day



Observations of interest from the above figures include:

- Microturbines recover more heat than fuel cells and ICEs. This is explained in part by the relatively lower electrical efficiency of microturbines. Lower electrical efficiency leaves more potential heat available for recovery.
- Variability is not significant throughout the day

- There were no Fuel Cells active in SCE service territory during peak
- During SDG&E peak ICE heat recovery was unavailable. Combining this with the electrical production figure reveals that there was a decrease in capacity factor over the same time period, which corroborates the finding
- Straight lines imply estimated rather than metered heat recovery

California Air Resources Board (CARB) NOx Compliance

Beginning in 2005, in addition to meeting the waste heat utilization requirement, nonrenewable-fueled engine/turbine projects submitting applications to the SGIP also have to meet the 2005 CARB NO_x emission standard of 0.14 lbs/MW-hr. This standard can be met by using a fossil fuel combustion emission credit for waste heat utilization so long as the system meets the 60 percent minimum efficiency standard. The following formula is used to determine system efficiency:

$$SystemEfficiency = \frac{(E+T)}{F}$$

Where E is the generating system's rated electric capacity converted into equivalent Btu per hour, T is the generating system's waste heat recovery rate (Btu per hour) at rated capacity, and F is the generating system's higher heating value (HHV) fuel consumption rate (Btu per hour) at rated capacity.

The waste heat utilization credit is calculated by the following equation:

$$MW_{WH} = \frac{UtilizedWasteHeat\left(\frac{1}{3.4}\right)}{EFLH}$$

Where *UtilizedWasteHeat* is the annual utilized waste heat in MMBtu per year, 3.4 is the conversion factor from MWh to MMBtu, and *EFLH* is the system's annual equivalent full load hours of operation.

The following equation is used to determine if the system meets the NO_x requirement:

$$NO_x = \frac{NO_x emissionrate}{MW_r + MW_{WH}}$$

Where $NO_x emissionrate$ is the system's verified emissions in pounds per MWh without thermal credit, MW_r is the system's rated capacity in MW, and MW_{WH} is the waste heat utilization credit in MW. The result will be a NO_x emission rate (lbs per MWh) which utilizes the thermal credit. If this rate is less than 0.14 lbs per MWh then the system qualifies.

As of December 31, 2006, 20 nonrenewable-fueled engines/turbines have come online under this new program requirement. Of the 20 systems, seven are microturbines, two are gas turbines, and 11 are internal combustion engines. With the addition of the NO_x requirement it appears that less internal combustion projects are being completed due to the additional cost of installing NO_x controls, while more microturbine projects are being completed because microturbines have low NO_x emissions before using NO_x controls. All 20 systems have gone through NO_x emission tests and theoretically meet the CARB NO_x requirement. However it cannot be determined if these systems are meeting the standard under normal operating conditions because HEAT data is not yet available for any of these systems.

AB 1685 (60%) Efficiency Status

System efficiencies were calculated for each nonrenewable-fueled cogeneration technology active in 2006. Table 5-16 provides summary statistics for each technology at the program level.

Table 5-16: Overall System Efficiency

Summary Statistic	Fuel Cells (FC)	Internal Combustion Engines (ICE)	Microturbines (MT)
N	11	181	96
Min	57%	0%	0%
Max	71%	86%	50%
Median	70%	50%	37%
Mean	68%	48%	35%
Std Dev	4%	9%	7%

As shown, fuel cells are most successful in meeting the AB 1685 efficiency standard. In fact, only one of the eleven fuel cell systems failed to meet this standard. On the other hand, only four ICE systems met the standard and no MT systems met the standard. This result has important program design implications and should be examined periodically to assess improvement.

5.5 Greenhouse Gas Emission Reductions

Due to the continued interest and concern over the release of energy-related greenhouse gas (GHG) emissions, the impact of GHG emissions from SGIP projects during the 2006 program year was examined using a methodology similar to the one used to calculate the net change in GHG emissions in the SGIP Fifth Year Impact Evaluation Final Report[13]. While the basic approach remains the same, impacts presented in this report are refined to a greater level of detail. Instead of reporting net GHG emission reductions by incentive level (e.g., Level 1, 2, 3, 3-N, and 3-R) as they were before, impacts are presented in this report by technology and fuel group (e.g., renewable fueled microturbines, nonrenewable fueled gas turbines, renewable fueled fuel cells, etc.). This more detailed presentation allows for a deeper understanding of the type of cogeneration systems leading to the greatest net change in CO_2- and CH_4-specific GHG emissions.

GHG Analysis Approach

As in 2005, the net change in GHG emissions due to the operation of SGIP systems on-line during PY06 was based on metered electricity data. GHG emission reduction estimates derive from three sources:

1. Net differences in CO_2 emissions resulting from electricity supplied to utility customers from central station generation facilities versus electricity supplied by the customer's own SGIP generator;
2. Net CO_2 emission reductions due to electricity normally supplied from central station generation facilities to drive electrical chillers, but which instead is supplied by waste heat recovered from SGIP facilities and used to drive absorption chillers; and
3. Methane captured and used by biogas-fired SGIP facilities.

The only difference in the analysis approach used in the Fifth Year Impacts Evaluation Report and this Sixth Year Report is the waste heat recovery rates. Recovery and use of waste heat at cogeneration sites reduces reliance on electricity generated from conventional power plants. Rates of waste heat recovery are therefore an essential part of estimating reductions of GHG emissions due to the SGIP. Average waste heat recovery rates were used in the 2005 Impacts Evaluation Report. The 2006 analysis approach uses technology-specific waste heat recovery rates based upon actual and estimated data from SGIP projects.

[13] Itron, Inc. CPUC Self-Generation Incentive Program Fifth Year Impact Evaluation: Final Report. Submitted to Pacific Gas and Electric Company and the Self-Generation Incentive Program Working Group. March 1, 2007.

GHG Analysis Results

Due to their different GHG emission sources, results are broken down by wind and PV facilities; non-renewable cogeneration facilities; and renewable-fuel (i.e., biogas-fueled) SGIP facilities.

GHG Reductions from PV and Wind Projects

The only source of GHG reductions from PV and wind projects is due to direct displacement of electricity that would have otherwise been generated from natural gas fired central station power plants. As a result, GHG emission reductions are based on the amount of CO_2 that would have been generated by the mix of utility electricity generation sources. Table 5-17 shows the reduction of CO_2-specific GHG emissions for PV and wind turbine projects. PV projects have greater GHG reductions relative to wind turbines (62,000 tons compared to just over 1,200 tons), because PV projects generated a much larger quantity of energy in comparison to wind turbine projects (103,306 MWh versus 2,102 MWh).

Table 5-17: Reduction of CO_2 Emissions from PV and Wind Projects in 2006 (Tons of CO_2)

Technology	Tons of CO_2 Emissions Reduced	Annual Energy Impact (MWhr)	CO_2 Factor (Tons/MWhr)
Photovoltaics	62,253	103,306	0.60
Wind Turbines	1,265	2,102	0.60
Total	**63,518**	**105,408**	**0.60**

GHG Reductions from Non-renewable Cogeneration Projects

Unlike PV and wind projects, non-renewable cogeneration projects realize GHG reductions from more than just direct displacement of grid-based electricity. Non-renewable cogeneration facilities also realize GHG reductions due to displacement of natural gas burned in boilers to provide process heating. The natural gas is displaced through the use of waste heat recovery systems incorporated into the SGIP facilities. In addition, some of the non-renewable cogeneration SGIP facilities use recovered waste heat in absorption chillers to provide facility cooling. If the absorption chillers replaced electric chillers, then net CO_2 reductions can accrue from the displaced electricity that would otherwise have driven the electric chiller. Table 5-18 provides a breakdown of CO_2 emissions from the various CO_2 sources possible for non-renewable SGIP cogeneration facilities and the overall net CO_2 reduction. Review of the net overall CO_2 reductions for each technology illustrates the importance of waste heat recovery on CO_2 reduction. For example, CO_2 emissions from IC engines exceed the amount of CO_2 associated with the direct displacement of grid electricity. Without waste heat recovery, IC engines would show a net gain in CO_2. Instead, indirect displacement of CO_2 through waste heat recovery provided IC engines with a net overall reduction in CO_2.

Table 5-18: Reduction of CO_2 Emissions from Non-renewable Cogeneration Projects in 2006 Categorized by Direct/Indirect Displacement (Tons of CO_2)

Technology	Direct Displacement from Grid	Cogeneration Emissions Released	Indirect Displacement through Waste Heat Recovery	Indirect Displacement from Absorption Chillers	Net CO_2 Emission Reductions
Fuel Cells	14,623	-11,750	3,240	63	6,176
Microturbines	25,936	-42,600	5,808	550	-10,306
IC Engines	195,745	-230,815	30,038	5,104	72
Gas Turbines	30,414	-49,896	11,967	90	-7,425
Total	**266,718**	**-335,061**	**51,053**	**5,807**	**-11,483**

It is beneficial to have a net CO_2 reduction factor in assessing the overall GHG implications associated with SGIP DG facilities and making comparisons between DG technologies. Table 5-19 is a listing of net CO_2 factors (in tons of CO2 reduced per MW-hr of electricity generated) for non-renewable cogeneration technologies. Negative net CO_2 reduction factors represent a net increase in CO_2 relative to electricity generated from the mix of utility central station power plants. The CO_2 factors for non-renewable projects range from a high of 0.24 tons per MWh for fuel cells to a low of -0.22 tons per MWh for microturbines. The non-renewable cogeneration CO_2 reduction factors are much smaller than the 0.6 tons per MWh factor calculated for PV and wind turbines.

Table 5-19: Reduction of CO_2 Emissions from Non-renewable Cogeneration Projects in 2006 (Tons of CO_2)

Technology	Tons of CO_2 Emissions Reduced	Annual Energy Impact (MWhr)	CO_2 Factor (Tons/MWhr)
Fuel Cells	6,176	26,170	0.24
Microturbines	-10,306	47,202	-0.22
IC Engines	72	353,436	0.0002
Gas Turbines	-7,245	55,287	-0.13
Total	**-11,303**	**482,095**	**-0.024**

GHG Reductions from Renewable (Biogas) Projects

The last fuel and technology combinations considered in this GHG emission reduction impact analysis are fuel cells, microturbines, and IC engines fueled with renewable biogas. Some of the biogas powered SGIP facilities generate only electricity, but some are cogeneration facilities that use waste heat recovery to produce process heating or cooling. Consequently, biogas powered cogeneration facilities can reduce CO_2 emissions in the same way as non-renewable cogeneration facilities, but can also include GHG emission reductions due to captured methane (CH_4).

Table 5-20 provides a listing of CO_2 reductions occurring from biogas powered cogeneration facilities. Similar to the non-renewable cogeneration facilities, CO_2 reductions can accrue from direct displacement and indirect displacement sources.

Table 5-20: Reduction of CO_2 Emissions from Renewable Cogeneration Projects in 2006 Categorized by Direct and Indirect Displacement (Tons of CO2)

Technology	Direct Displacement from Grid	Cogeneration Emissions Released	Indirect Displacement through Waste Heat Recovery	Indirect Displacement from Absorption Chillers	Net CO_2 Emission Reductions
Fuel Cells	1,379	-1,121	328	0	586
Microturbines	5,109	-8,377	587	281	-2,400
IC Engines	5,600	-6,683	1,346	0	263
Total	**12,088**	**-16,180**	**2,261**	**281**	**-1,551**

As indicated earlier, biogas powered SGIP facilities not only realize GHG reductions due to CO_2 reductions, but also due to captured methane. In particular, this is methane that would have otherwise been emitted to the atmosphere. When reporting GHG emission reductions from different types of greenhouse gases, the convention is to report the GHG reductions in terms of tons of CO_2 equivalent. Methane has a GHG equivalence twelve times that of CO_2 and so methane reductions from biogas powered SGIP facilities can be converted to CO_2 equivalent through this conversion factor.

An analysis of the SGIP tracking data showed a list of 20 facilities that relied upon renewable biogas fuels during 2006. 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.[14] Table 5-21 presents the tons of CH_4 emissions avoided and tons of CO_2 equivalent[15] by renewable fuel technology type. The largest reduction of methane-specific GHG emissions comes from renewable fueled microturbines, which are responsible for almost 75% of the total methane emission reductions. Renewable fuel cells and renewable IC engine cogeneration systems are responsible for much smaller fractions of the total methane-specific GHG emission reductions. This difference in tons of emissions reduced by renewable fuel technology type stems from the number of facilities using each type of technology. Of the cogeneration

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

[15] 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

systems that rely upon renewable fuel sources, 15 are microturbine, 1 is fuel cell, and 4 are internal combustion engine facilities.

Table 5-21: Reduction of CH_4 Emissions from Renewable Cogeneration Projects in 2006 (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	224	4,699
Internal Combustion Engines	406	8,516
Microturbines	1,750	36,148
Total	**2,380**	**49,963**

Total Net Change in GHG Emissions

To determine the total net GHG impact of SGIP facilities during 2006, the net GHG reductions must be reported in units of CO_2 equivalent to allow a basis of comparison. Table 5-22 shows the tons of GHG emissions reduced in tons of CO_2 equivalent, broken down by the different SGIP fuel and technology combinations. [16] The total reduction of GHG emissions measured in CO_2 equivalent units is approximately 100,630 tons with the largest portions of this reduction coming from photovoltaic projects, followed by renewable fueled microturbines. During the 2005 program year, the total GHG emission reduction calculated for the SGIP projects was slightly less at 93,000 tons of CO_2 equivalent. Most of these reductions also came from PV projects as well. We can also see that the fuel/technology cogeneration group contributing the largest energy impact is non-renewable fueled IC engines.

The last column in Table 5-22 presents ratios of the tons of GHG emissions reduced per MWh generated by each fuel and technology category for the 2006 program year. Renewable fuel technologies have the highest ratios (mostly due to the potent CH_4 emission reductions), while non-renewable microturbines have the lowest. Unlike in the 2005 Impacts Report where a single ratio for the Level 3, 3-R, and 3-N projects was presented, we were able to disaggregate our results to the fuel/technology level because annual energy impacts were available at this level for this evaluation. The CO_2 factors range from a high of 3.70 for renewable fuel microturbines to a low of -0.22 for non-renewable fueled microturbines. It is interesting to note that the ratio of tons of CO_2 equivalent reduced per MWh is now positive for renewable fueled microturbines because methane reductions from this group of projects is considered in the table below. When only CO_2 emissions are considered, this project group emits more emissions than it reduces.

[16] Note that the results in Table 5-I can be developed by adding the equivalent CO_2 values in Table 5-H to the direct CO_2 values in Table 5-B, Table 5-D, and Table 5-F.

Table 5-22: Net Reduction of GHG Emissions from SGIP Systems Operating in Program Year 2006 (Tons of CO2 eq.) by Fuel and Technology and Ratios of Tons of GHG Reductions per MWh

Technology	Tons of CO_2 eq. Reduced	Annual Energy Impact (in MWh)	CO_2 eq. Factor (Tons/MWhr)
Photovoltaics	62,253	103,306	0.60
Wind turbines	1,265	2,102	0.60
Non-renewable fuel cells	6,176	26,170	0.24
Non-renewable MT	-10,306	47,202	-0.22
Non-renewable fueled ICE	72	353,436	0.0002
Non-renewable and waste gas fueled small gas turbines	-7,245	55,287	-0.13
Renewable fueled fuel cells	5,285	2,498	2.12
Renewable fueled MT	34,348	9,281	3.70
Renewable fueled IC Engines	8,779	10,233	0.86
TOTAL	**100,627**	**609,515**	**0.17**

Net Change in GHG Emissions by Program Administrator

Table 5-23 through Table 5-26 present the reduction of CO_2 emissions in 2006 by Program Administrator and fuel/technology group.[17] These tables also include the annual energy impact and the CO_2 factor for each group as well. A comparison of these tables show that the PA responsible for the largest reduction of CO_2 emissions is PG&E (28,884 tons) followed by SCE (10,901 tons), CCSE (9,192), and SCG (1,550 tons). In fact, PG&E projects reduce more than two times the amount of emissions than SCE. As far as energy impacts are concerned, PG&E's projects generate the most overall (268,480 MWh), followed by SCG (197,823 MWh), SCE (86,601 MWh), and CCSE (56,611).

[17] Note that the California Center for Sustainable Energy (CCSE) is the program administrator for San Diego Gas and Electric Company.

Table 5-23: Technology Specific CO_2 Reductions for PG&E

Technology	Tons of CO_2 Reduced	Energy Impact in MWh	CO_2 Factor (Tons/MWhr)
Photovoltaics	32,727	55,796	0.59
Wind turbines	-	-	-
Non-renewable fuel cells (6 projects)	3,377	14,893	0.23
Non-renewable MT (33 projects)	-3,239	15,250	-0.21
Non-renewable fueled ICE (73 projects)	-661	156,163	0.004
Non-renewable and waste gas fueled small gas turbines (2 projects)	-2,565	17,944	-0.14
Renewable fueled fuel cells	-	-	-
Renewable fueled MT (9 projects)	-882	3,549	-0.25
Renewable fueled ICE (6 projects)	87	4,885	0.11
TOTAL	**28,884**	**268,480**	**0.11**

Table 5-24: Technology Specific CO_2 Reductions for SCE

Technology	Tons of CO_2 Reduced	Energy Impact in MWh	CO_2 Factor (Tons/MWhr)
Photovoltaics	12,782	20,442	0.63
Wind turbines	1,265	2,102	0.60
Non-renewable fuel cells	134	493	0.27
Non-renewable MT	-2,597	11,821	-0.22
Non-renewable fueled ICE	1	38,543	0.00
Non-renewable and waste gas fueled small gas turbines	-	-	-
Renewable fueled fuel cells	586	2,498	0.23
Renewable fueled MT	-1,446	5,354	-0.27
Renewable fueled IC Engines	176	5,348	0.03
TOTAL	**10,901**	**86,601**	**0.13**

Table 5-25: Technology Specific CO_2 Reductions for SCG

Technology	Tons of CO_2 Reduced	Energy Impact in MWh	CO_2 Factor (Tons/MWhr)
Photovoltaics	8,063	13,093	0.62
Wind turbines	-	-	-
Non-renewable fuel cells	533	1,921	0.28
Non-renewable MT	-3,889	17,220	-0.22
Non-renewable fueled ICE	1,218	130,897	0.009
Non-renewable and waste gas fueled small gas turbines	-4,375	34,692	-0.13
Renewable fueled fuel cells	-	-	-
Renewable fueled MT	-	-	-
Renewable fueled IC Engines	-	-	-
TOTAL	**1,550**	**197,823**	**0.008**

Table 5-26: Technology Specific CO_2 Reductions for CCSE

Technology	Tons of CO_2 Reduced	Energy Impact in MWh	CO_2 Factor (Tons/MWhr)
Photovoltaics	8,681	13,976	0.62
Wind turbines	-	-	-
Non-renewable fuel cells	2,132	8,863	0.24
Non-renewable MT	-580	2,911	-0.20
Non-renewable fueled ICE	-484	27,833	-0.02
Non-renewable and waste gas fueled small gas turbines	-486	2,650	-0.18
Renewable fueled fuel cells	-	-	-
Renewable fueled MT	-71	378	-0.19
Renewable fueled IC Engines	-	-	-
TOTAL	**9,192**	**56,611**	**0.16**

The overall CO_2 factor is shown for each PA and is calculated by dividing the total emissions reduced by the total annual energy impact. A comparison of these factors show that CCSE has the highest ratio (0.17), followed by PG&E and SCE (both with ratios of 0.14). A more detailed examination of the CO_2 factors shows that the PA-specific ratios are highest for PV projects and tend to be lowest for renewable and non-renewable fueled microturbines.

The remaining three tables, Table 5-27 through Table 5-29, show the methane reductions by PA and renewable fuel technology group (the renewable fuel technologies are the only types to have measurable impacts on CH_4-specific GHG emissions). In this case, SCE reduces the largest quantity of emissions (1,149 tons), followed closely behind by PG&E (1,137 tons). The renewable fuel projects under CCSE are responsible for a much smaller fraction of CH_4 reductions at just under 100 tons. This is due to the fact that CCSE oversees only 3 microturbine projects while SCE oversees 1 fuel cell, 1 internal combustion engine, and 3 microturbine projects. It is interesting to not that PG&E oversees even more projects (9 microturbine and 3 internal combustion engine projects) but does not reduce more methane emissions than SCE.

Table 5-27: Technology Specific CH_4 Reductions for PG&E (in tons of CH_4 and tons of CO_2 eq.)

Technology	Tons of CH_4 Reduced	Tons of CO_2 eq. Reduced
Fuel Cells	-	-
Microturbines (9 projects)	872	18,312
IC Engines (3 projects)	265	5,565
TOTAL	**1,137**	**23,877**

Table 5-28: Technology Specific CH_4 Reductions for SCE (in tons of CH_4 and tons of CO_2 eq.)

Technology	Tons of CH_4 Reduced	Tons of CO_2 eq. Reduced
Fuel Cells (1 project)	224	4,7,04
Microturbines (3 projects)	785	16,485
IC Engines (1 project)	140	2,940
TOTAL	**1,149**	**24,129**

Table 5-29: Technology Specific CH_4 Reductions for CCSE (in tons of CH_4 and tons of CO_2 eq.)

Technology	Tons of CH_4 Reduced	Tons of CO_2 eq. Reduced
Fuel Cells	-	-
Microturbines (3 projects)	93	1,953
IC Engines	-	-
TOTAL	**93**	**1,953**